VERIFIED DIRECT TESTIMONY OF KEVIN J. BLISSMER

Q1. Please state your name, business address and title.

A1. My name is Kevin J. Blissmer. My business address is 801 E. 86th Avenue, Merrillville, Indiana 46410. I am Manager of Regulatory for NiSource Corporate Services Company ("NCSC").

Q2. On whose behalf are you submitting this direct testimony?

A2. I am submitting this testimony on behalf of Northern Indiana Public Service Company LLC ("NIPSCO").

Q3. Please describe your educational and employment background.

A3. I graduated from Purdue University with a Bachelor of Science Degree majoring in both Accounting and Finance. I was employed at Universal Access, a small public telecommunications company based in Chicago, Illinois for three years, where I progressed in my career to Assistant Controller before leaving to join NiSource Inc. ("NiSource"). I joined NiSource in 2003 as the Manager of SEC Reporting and Research until 2010, after which I held roles as Manager of Accounting Research and Manager of Corporate Finance before joining NIPSCO's Rates and Regulatory

Finance Department in 2014 as the Manager of Regulatory Accounting. On November 1, 2017, I accepted my current position as Manager of Regulatory.

Q4. What are your responsibilities as Manager of Regulatory?

A4. I am responsible for the preparation and coordination of many of NIPSCO's electric tracker filings, including NIPSCO's Fuel Adjustment Clause ("FAC") filings (Cause No. 38706-FAC-XXX), Electric Transmission, Distribution, and Storage Improvement Charge ("TDSIC") filings (Cause No. 44733-TDSIC-X), Electric Demand Side Management ("DSM") filings (Cause No. 43618-DSM-XX), Resource Adequacy tracker filings (Cause No. 44155-RA-XX), Regional Transmission Organization ("RTO") Adjustment tracker filings (Cause No. 44156-RTO-XX), and Green Power Rider ("GPR") filings (Cause No. 44198-GPR-XX). I am also responsible for the preparation and coordination of NIPSCO's annual Attachment O, GG, and MM postings to the Midcontinent Independent System Operator, Inc..

Q5. Have you previously testified before the Indiana Utility Regulatory Commission ("Commission") or any other regulatory commission?

A5. Yes. I previously submitted testimony before the Commission in NIPSCO's most recent electric rate case in Cause No. 45772 and in NIPSCO's request for a Certificate of Public Convenience and Necessity ("CPCN") for federally mandated projects in Cause Nos. 45700 and 45797. I also routinely file testimony before the Commission in support of various electric trackers, including NIPSCO's FAC filings (FAC-131 and FAC-136), TDSIC filings (TDSIC-4, TDSIC-5, TDSIC-6), DSM filings (DSM-15 through DSM-18), RTO filings (RTO-11 through RTO-19), and GPR filings (GPR-10 through GPR-15).

Q6. What is the purpose of your direct testimony in this proceeding?

A6. The purpose of my direct testimony is to support NIPSCO's request for a CPCN to construct a natural gas combustion turbine ("CT") peaker plant (the "CT Project") on available property at the R.M. Schahfer Generating Station ("Schahfer") site. Specifically, I support NIPSCO's request for authorization for financial incentives for the CT Project as a clean energy project, including timely cost recovery through construction work in progress ("CWIP") ratemaking, under Ind. Code § 8-8.8-11 ("Section 11"). I also support NIPSCO's request to implement a Generation Costs Tracker ("GCT") Mechanism to record and recover costs associated with NIPSCO's proposed CT Project. I provide: (1) an overview of the proposed GCT Mechanism; (2) a description of the proposed ratemaking treatment related to the GCT Mechanism; (3) an explanation of how the GCT Mechanism revenue requirement and the related factors will be calculated; (4) a description of the allocators NIPSCO proposes to use to allocate the various components of the GCT Mechanism; (5) a description of the depreciation rates for the CT Project; (6) the proposed timeline for NIPSCO's initial and future GCT Mechanism tracker filings; and (7) a description of the additional changes to NIPSCO's electric service tariff. I also provide the estimated monthly bill impact as a result of the CT Project for an average residential customer. Finally, I explain how NIPSCO is accounting for preliminary, survey and investigation planning costs related to this project.

Q7. Are you sponsoring any attachments to your direct testimony in this Cause?

A7. Yes. I am sponsoring Attachment 8-A through Attachment 8-C, all of which were prepared by me or under my direction and supervision.

Q8. Are NIPSCO's books and records kept in accordance with the Uniform System of Accounts and Generally Accepted Accounting Principles?

A8. Yes.

Q9. Please provide an overview of the proposed GCT Mechanism.

A9. NIPSCO is seeking authority to implement a semi-annual retail rate adjustment mechanism through which NIPSCO will timely recover costs associated with the CT Project.

Q10. Please describe the ratemaking treatment NIPSCO is requesting related to the GCT Mechanism.

A10. NIPSCO is requesting to recover on a timely basis its capital, depreciation, tax, and financing costs incurred during construction of the CT Project through CWIP ratemaking. This past legislative session, the Indiana General Assembly enacted House Enrolled Act 1421 ("HEA 1421"). Among other things, HEA 1421 amended the definition of "clean energy projects" in Ind. Code § 8-1-8.8-2 to include "[p]rojects to construct or repower a facility described in IC 8-1-37-4(a)(21)." NIPSCO Witness Walter explains how the proposed CT Project qualifies as a clean energy project. HEA 1421 also amended Ind. Code § 8-1-8.8-11(a)(1) limiting when CWIP ratemaking can be authorized for a clean energy project as a financial incentive.

Q11. Please describe the new requirement relating to the authorization of

CWIP ratemaking for a clean energy project as a financial incentive.

A11. HEA 1421, among other provisions, amends Section 11(a) concerning financial incentives to provide:

> The commission may not approve a financial incentive under this subdivision unless the commission finds that the eligible business has demonstrated that the timely recovery of costs and expenses incurred during the construction and operation of the project: (A) is just and reasonable; and (B) in the case of construction financing costs, will result in a gross financing savings over the life of the project.

NIPSCO's proposal satisfies both additional requirements.

Q12. Relating to Subpart (B) and the production of gross financing savings, how will CWIP ratemaking work under NIPSCO's proposal?

A12. NIPSCO proposes to implement CWIP ratemaking treatment related to the recovery of financing costs incurred during the construction of the CT Project. Under CWIP ratemaking treatment, NIPSCO would recover, through the GCT Mechanism, financing costs incurred during the construction period for the proposed CT Project. These costs would be recovered at NIPSCO's weighted average cost of capital ("WACC"). Under NIPSCO's proposal, the financing costs under CWIP ratemaking would be recovered on a forward looking basis as the capital costs are incurred while the project is under construction. Under NIPSCO's proposal, almost all accrual of allowance for funds used during construction ("AFUDC") will be eliminated. In connection with CWIP ratemaking, NIPSCO will cease accruing AFUDC on the earlier of the date in which such expenditures receive CWIP ratemaking treatment or the date the CT Project is placed in service. As such, the only AFUDC that will accrue is the AFUDC that either has already been accrued or will have been accrued by the time rates become effective in NIPSCO's first GCT Mechanism filing (currently estimated to be October, 2024).

Q13. What is the difference between CWIP ratemaking, AFUDC and post in service carrying charges ("PISCC")?

A13. CWIP ratemaking allows a utility to include its capital investment in its rate base during construction. This permits the utility to recover its financing costs during construction, rather than accruing those costs. The alternative to CWIP ratemaking is to capitalize the carrying cost of the capital investment as AFUDC while the asset is under construction. In contrast to CWIP, under AFUDC treatment, the financing costs are capitalized as part of plant during construction and included in rate base when the asset is placed in-service. Once the asset is placed in-service, PISCC on an asset such as the CT Project is accrued, as a regulatory asset, until the asset is reflected in rates. The PISCC regulatory asset is included in rate base and amortized over the life of the underlying asset, producing a result that is very similar to the effect of accruing AFUDC (increasing the cost of the asset reflected in rate base). Accruing AFUDC and PISCC results in a higher rate base amount included in a base rate case compared to CWIP ratemaking. Under CWIP ratemaking, customers avoid the compounding effects of accrued AFUDC and PISCC.

Q14. How does the use of CWIP ratemaking impact the revenue requirement?

A14. CWIP ratemaking is, in part, a timing mechanism. It does not change the amount of direct construction costs, but it eliminates the compounding of carrying costs, thereby producing a lower rate base, which results in a lower annual revenue requirement. Permitting an earlier cash flow than would otherwise be produced by AFUDC and PISCC treatments ultimately reduces customer rates.

Q15. Relating to Subpart 11(B), will the CWIP ratemaking that NIPSCO is proposing result in gross financing savings over the life of the project?

A15. Yes. As shown in <u>Attachment 8-A</u>, the construction financing costs will result in a gross financing savings over the life of the project. The Summary tab in Attachment 8-A includes the results from the data contained in the remaining tabs and presents two scenarios: (1) the top half presents the revenue requirement and financing costs portion of the revenue requirement under NIPSCO's proposed CWIP ratemaking treatment, and (2) the bottom half presents the same information under an alternative scenario where the asset is reflected in rates after being placed in service as part of a general rate case.[1] Under both scenarios, the CT is assumed to be placed in service in December, 2026, the general rate case test year is assumed to be calendar year 2027, and the Step 1 rates in that general rate case are assumed to become effective on a bills rendered basis commencing with the September 1, 2027 billing cycle. From that point forward, the sequence and timing of rate implementation under both scenarios is the same, as the CT Project under the GCT will have rolled into base rates. The only difference from September 2027 over the remaining life of the project

[1] As set forth in the Verified Petition in this Cause, NIPSCO seeks relief in the alternative under Section 11(a) to accrue PISCC and to defer depreciation from the date the CT Project is placed in service until the cost of the CT Project is reflected in NIPSCO's rates either through the GCT Mechanism or in a general rate case, all as described in the Verified Petition. The request for alternative relief would trigger in the event the proposed GCT is not approved as proposed, which could be either the denial of the GCT or rejection of the forward looking nature of the GCT. Either of these changes to NIPSCO's proposal would result in PISCC and the commencement of depreciation before rate recovery has commenced.

is the result of the higher accrued rate base (including regulatory asset) produced by the accrual of AFUDC and PISCC under the traditional model.

Q16. Please describe the first scenario in the top half of the Summary tab (the CWIP proposal) until September 1, 2027.

A16. The top half of the Summary tab shows the recovery of the financing costs through the proposed CWIP ratemaking until the CT Project is reflected as being in service and in base rates resulting from the assumed 2027 general rate case. Based upon the timing of this case, NIPSCO anticipates putting rates in effect under the GCT on a bills rendered basis commencing with the October 1, 2024 billing cycle.

Q17. On the top half of the Summary tab, what is included in the line item for Expense Tracker?

A17. Under its proposal, NIPSCO will reflect depreciation expense and property taxes on the CT Project in the GCT. These are the expenses reflected in the line item for Expense Tracker.

Q18. For both scenarios (the top half and the bottom half) why have property taxes been removed?

A18. Since property taxes are not financing costs, and Section 11 requires a comparison of gross financing costs, property taxes have been removed.

Q19. Why has depreciation expense not been removed under the same reasoning?

A19. Depreciation expense has not been removed because the regulatory asset resulting from the deferral of depreciation expense would be reflected in rate base. Depreciation results in differential financing costs under the two scenarios so depreciation expense should not be removed.

Q20. What is the conclusion of your analysis?

A20. The total financing costs over the life of the CT Project are set forth in the Revenue from Financing Costs line item. Under NIPSCO's CWIP proposal (the top half), the total revenue from financing costs is $1,594,896,529. Under the traditional general rate case scenario (the bottom half), the total revenue from financing costs is $1,744,668,836. The difference between these two amounts of $149,772,307 is the gross financing savings over the life of the CT Project.

Q21. Why is NIPSCO's proposed CWIP ratemaking forward looking?

A21. As described more fully below, NIPSCO's proposal is to reflect the CWIP financing costs projected to occur over the next respective six-month billing period in each tracker filing. So there will be no AFUDC reflected in the total cost of the CT Project except for the very limited AFUDC that has already been accrued and is expected to be accrued until rates take effect in October 2024 under the GCT. If the tracker were backward looking and reflected the CWIP financing costs that had been incurred over the previous six months, the overall gross financing savings would be reduced and produce ultimately higher rates for customers.[2] Although a backward looking CWIP proposal would produce gross financing savings over the life of the CT Project, the savings would be lower and the result would be more costs for customers.

Q22. Returning to the language in Section 11(a), is NIPSCO's proposed financial incentive of CWIP ratemaking just and reasonable?

A22. Yes. The gross financing savings produces lower rates for customers. Also, NIPSCO's proposal improves its cash flows and avoids rate shock to customers.

[2] See footnote 1.

Q23. Is there also a benefit to NIPSCO from utilizing CWIP ratemaking?

A23. Yes. The primary benefit for a utility from CWIP ratemaking, from a financial health standpoint, is that it will provide NIPSCO cash flow during a potentially lengthy construction period. Rating agencies believe CWIP ratemaking improves overall credit quality:

> [T]he inclusion of CWIP in rate base is supportive of utility credit quality. It helps moderate the financial pressure of the incremental construction related debt by providing a cash return during lengthy, sometimes uncertain, and potentially delayed construction periods. It also allows a project's costs to be gradually incorporated into rates rather than all at once at the conclusion of construction, when a large and unpopular one-time rate increase may be required. The resulting rate shock could lead to further delays in the recovery of these costs or political/legislative intervention aimed at limiting or denying utility cost recovery altogether. [3]

CWIP ratemaking improves near term cash flow and mitigates the negative effects of the significant additional debt taken on to construct the project.

Q24. How do customers otherwise benefit from recovery of CWIP in rate base?

A24. I have spent a considerable portion of my testimony explaining how CWIP ratemaking produces lower rates for customers so I will not repeat that here. In addition to the overall savings, it has long been recognized that

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[3] Moody's Global Infrastructure, Industry Outlook: US Investor-Owned Electric Utilities: Six-Month Industry Update, at 3 (July 2008).

CWIP ratemaking is a benefit to customers because it prevents so-called "rate shock."[4] For large capital projects, waiting until the project enters service to include costs in rate base can lead to a significant one-time increase in the rate base and, in return, rates. CWIP protects against that type of rate shock by phasing in the costs of the new facilities over the construction period.

Q25. Please describe the accounting treatment associated with CWIP ratemaking.

A25. A utility must discontinue the capitalization of AFUDC once it begins recovery of CWIP. Under NIPSCO's proposal, and except for the AFUDC currently being accrued and continuing to accrue until recovery of CWIP through the proposed tracker, NIPSCO will not accrue AFUDC in FERC Account 107, Construction Work in Progress for the CT Project. Moreover, NIPSCO will use the PowerPlant system to maintain its accounting records for CWIP electric plant assets during construction and after the CT Project

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[4] *See, e.g., Tucson Elec. Power Co.*, 174 FERC ¶ 61,223 at P 25 (2021) (stating that allowing transmission developers "to include 100% CWIP in rate base would result in greater rate stability for customers by reducing 'rate shock' when certain large-scale transmission projects come on line.") (citing 2012 Incentives Policy Statement, 141 FERC ¶ 61,129 at P 12 (2012) (citing *PJM Interconnection, L.L.C.*, 135 FERC ¶ 61,229 (2011)); *see also PPL Elec. Utils. Corp.*, 123 FERC ¶ 61,068, at P 43, *reh'g denied*, 124 FERC ¶ 61,229 (2008))).

is placed in service. The PowerPlant system has the capability to identify specific work orders or projects that should not be included in the calculation and capitalization of AFUDC. The work orders related to the CT Project will be identified in PowerPlant system, and no AFUDC will be calculated in their balances once CWIP ratemaking has begun.

<u>Proposed GCT Mechanism</u>

Q26. How does NIPSCO propose to recover the return on capital and other appropriate costs during construction and after the CT Project is placed in service but before inclusion in base rates should the Commission grant NIPSCO's request for CWIP ratemaking for the CT Project?

A26. NIPSCO proposes to recover these costs in a semi-annual forecasted capital tracker until such time as this project is included in base rates subsequent to it being placed in service. NIPSCO anticipates those filings will be made by June 1 (reflecting the forward looking period of October through March) and December 1 (reflecting the forward looking period of April through September). NIPSCO anticipates a 120-day procedural schedule from filing to Commission order and rate implementation (on a bills rendered basis). Any variance from the forecasted tracker revenue requirement and the amounts collected to the actual revenue requirement based on the final books and records would be captured in a reconciliation within each tracker filing as historical actual periods are available for each tracker filing. Attachment 8-B is an example of what the tracker schedules would most likely include.

Q27. Please describe how the capital costs associated with the CT Project will be incorporated into the GCT.

A27. The revenue requirement for capital costs included in the GCT will be calculated by first computing the monthly average CWIP, or net plant in service when appropriate, over the forecasted six-month period. NIPSCO would then multiply the weighted monthly average for the forecasted billing period by NIPSCO's monthly effective WACC which incorporates the Commission approved return on common equity and capital structure. These capital costs will be grossed up for all applicable taxes.

Q28. Please describe how all other costs, including depreciation and property tax expenses associated with the CT Project, will be incorporated into the GCT.

A28. Until and to the extent the CT Project is placed in service, there would be no depreciation expense. When and to the extent the CT Project is projected to be placed in service in a six-month forecast period, the GCT will commence recovery of the depreciation expense that would be reconciled when actual depreciation expense is recognized in a future tracker, which avoids any deferral of depreciation expense, producing lower rates for customers. If the GTC were historical, there would be deferral of depreciation until the depreciation expense is reflected in rates. Similarly, forecasted property taxes will be included in the GCT and reconciled when actual property tax expense is recognized in a future tracker.

Q29. Please describe the allocation factors NIPSCO proposes to use to allocate costs in the GCT Mechanism.

A29. NIPSCO proposes to allocate the costs associated with the CT Project based on NIPSCO's Commission approved demand allocators for the GCT Mechanism, whereby the demand allocators are based upon revenue attributable to each of NIPSCO's rate schedules used to establish NIPSCO's Commission approved electric base rates in Cause No. 45772. Additionally, NIPSCO will adjust its allocation percentages to reflect the significant migration of customers amongst the various rates for each semi-annual tracker filing, as it does with other tracking mechanisms. This adjustment is appropriate to prevent any unintended consequences of the migration of customers between rates and to properly allocate their share of the revenue requirement.

Q30. Please describe the depreciation rates that will apply to the CT project.

A30. Depreciation expense will be determined by utilizing the applicable depreciation rates approved in NIPSCO's most recent electric rate case in Cause No. 45772.

Q31. How does NIPSCO propose to treat the operating income associated with the capital costs associated with the CT Project for purposes of the earnings test in NIPSCO fuel adjustment clause ("FAC") proceedings?

A31. As part of the Section 11 financial incentive, NIPSCO proposes to include the operating income associated with the CT Project in the total electric Comparison of Electric Operating Income for purposes of the Ind. Code § 8-1-2-42(d) earnings test. This is also consistent with the treatment of earnings associated with both NIPSCO's Rider 588 – Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge initially approved in Cause No. 44371 and NIPSCO's Rider 587 – Adjustment of Charges for Federally Mandated Costs initially approved in Cause No. 44340.

Q32. Please describe NIPSCO's proposed timeline for future GCT filings.

A32. Based on NIPSCO's assumption that an order will be issued in this Cause in May, 2024, consistent with the 240-day period provided for Commission review under Ind. Code § 8-1-8.5-5(b), NIPSCO proposes to file its petition and case-in-chief by June 1 and December 1 each year with new rates becoming effective for bills rendered starting on October 1 and April 1, respectively. The petition filed on June 1 will be based on a forecast of the upcoming period of October through March. The petition filed on December 1 will be based on a forecast of the upcoming period April through September. A reconciliation of actual to forecasted expenses will be completed on a 12-month lag (*i.e.*, forecasted expenses from the GCT-1 tracker filing will be reconciled to actual expenses in the GCT-3 tracker filing).

Q33. Did NIPSCO include any actual or forecasted costs as part of this filing?

A33. No. Attachment 8-B contains illustrative schedules. In this filing, NIPSCO is proposing to file its first tracker petition on June 1, 2024 or within 30 days of a final order in this Cause, whichever is later. At that time, NIPSCO will include average projected CWIP balances from October 2024 through

March 2025 and actual and projected AFUDC through September 2024.[5] NIPSCO is proposing the first GCT factors to become effective for bills rendered by NIPSCO during the billing cycles of October 2024 through March 2025, or until replaced by different GCT factors that are approved in a subsequent filing. As noted above, these costs will be reconciled in NIPSCO's GCT-3 tracker filing.

Q34. Please explain the proposed changes to NIPSCO's electric service tariff relating to the proposed GCT Mechanism.

A34. As shown in Attachment 8-C, NIPSCO proposes the following changes to its electric service tariff relating to the proposed GCT Mechanism: (1) addition of Rider 595 – Generation Cost Tracker; (2) addition of Appendix L – Generation Cost Tracker Factors; (3) update to Appendix A to include Rider 595; and (4) update to the Table of Contents to add Rider 595 and Appendix L. Specifically, NIPSCO requests approval of the tariff pages attached hereto as Attachment 8-C.[6] Attachment 8-C includes a clean and redlined version.

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[5] This initial forecasted period exceeds the typical 6-month test period as NIPSCO is seeking recovery of forecasted amounts in addition to actual costs incurred.

[6] The changes also include a correction to the Sheet Nos. shown in the Table of Contents

Estimated Bill Impact

Q35. What is the estimated bill impact of the CT Project for an average residential customer?

A35. The exact impact will be dependent on a number of different factors. However, assuming issuance of a CPCN for the CT Project and approval of the proposed GCT Mechanism as described above, NIPSCO currently estimates that costs in the first GCT Tracker filing after approval would result in an incremental 2024 annualized charge of approximately $1.25 to a 668 kWh per month residential bill.

Planning Costs

Q36. Is NIPSCO incurring significant costs related to the planning and preparation of this proceeding and request?

A36. Yes. NIPSCO is currently carrying these preliminary, survey and investigation costs on its books and will record them to the cost of owned generating resources, a portion of which will be applied to the new CT Project. These costs are included in the best estimate of cost of construction of the CT Project presented by NIPSCO Witness Baacke.

(Sheet No. 4).

Q37. Does this conclude your prefiled direct testimony?

A37. Yes.

VERIFICATION

I, Kevin J. Blissmer, Manager of Regulatory of NiSource Corporate Services Company, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information, and belief.

Kevin J. Blissmer

Dated: September 12, 2023

Attachment 8-A

[See Excel document filed separately]

Attachment 1
Schedule 1

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC
Determination of Costs for Gas Costs Tracker
Estimates for the Six Month Billing Period October 2024 through March 2025

Line No.			
1	Total Net Capital (Att. 1, Sch. 2, Line 28)	$	187,316,256
2	Rate of Return (Att. 2, Schedule 1, Line 8)		6.88%
3	Annual Return on Net Capital (Line 1 x Line 2)	$	12,887,358
4	Adjusted Return for the billing period (Line 3 * 6/12)	$	6,443,679
5	Revenue Conversion Factor (Att 2, Sch 2, Line 12)		1.246846
6	Return on Net Capital Adjusted for Taxes (Line 4 x Line 5)	$	8,034,278
7	Total Expenses (Att, 1, Sch 3, line 16)	$	60,195
8	Prior Period Variance - Under / (Over) Collection (Att.1, Sch 4, p1)	$	-
9	Total Revenue Requirement for the Billing Period (Line 6 + Line 7 + Line 8)	$	8,094,473

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Rate Code	Demand Allocation Per Cause No.45772*	Demand Allocation % of Total	Total Demand Allocated Return Costs Col. c x Total Col. d	Total Demand Allocated Expense Costs Col. c x Total Col. e	Total Demand Allocated Variance Att. 1, Sch. 4, p1	Forecasted Semi-Annual kWh Sales	Rates ($/kWh) Col. [(d)+(e)+(f)] / (g)
10	511	$ 651,361,034	37.67%	$ 3,026,395	$ 22,674	$ -	1,628,032,748	$ 0.001873
11	520	1,173,276	0.07%	5,451	41	0	8,317,247	0.000660
12	521	301,700,945	17.45%	1,401,782	10,502	0	774,527,812	0.001823
13	522	1,097,669	0.06%	5,100	38	0	6,739,229	0.000762
14	523	166,962,652	9.66%	775,753	5,812	0	440,182,853	0.001776
15	524	219,613,694	12.70%	1,020,383	7,645	0	714,643,723	0.001439
16	525	9,298,955	0.54%	43,205	324	0	42,969,042	0.001013
17	526	189,829,558	10.98%	881,998	6,608	0	727,402,492	0.001222
18	531 - Tier 1	117,174,692	6.78%	544,425	4,079	0	628,621,155	0.000873
19	532	17,637,102	1.02%	81,947	614	0	79,118,659	0.001044
20	533	27,109,249	1.57%	125,957	944	0	107,942,845	0.001176
21	541	5,074,862	0.29%	23,579	177	0	13,740,581	0.001729
22	542	56,566	0.00%	263	2	0	171,985	0.001540
23	543	1,247,539	0.07%	5,796	43	0	2,235,850	0.002612
24	544	2,392,053	0.14%	11,114	83	0	7,250,600	0.001544
25	550	7,805,610	0.45%	36,267	272	0	18,458,507	0.001980
26	555	1,237,835	0.07%	5,751	43	0	3,078,697	0.001882
27	560	3,323,321	0.19%	15,441	116	0	8,064,033	0.001929
28	Interdpt	5,094,363	0.29%	23,670	177	-	10,657,147	0.002238
29	Total	$ 1,729,190,974	100.00%	$ 8,034,278	$ 60,195	$ -	5,222,155,205	

*As adjusted per Attachment 2, Schedule 3.

Attachment 1
Schedule 2

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC
Forecasted Net Capital for CT Project
Estimates for the Six Month Billing Period October 2024 through March 2025

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Construction Work in Process								
Line No.	**Capital Forecast Detail by Project**	Projected Capital Balance 9/30/2024	Projected Capital Balance 10/31/2024	Projected Capital Balance 11/30/2024	Projected Capital Balance 12/31/2024	Projected Capital Balance 1/31/2025	Projected Capital Balance 2/28/2025	Projected Capital Balance 3/31/2025	Weighted Average Capital Balance Oct '24 - Mar '25
1	Electric Interconnect	$ 3,252,203	$ 4,316,561	$ 5,380,918	$ 5,913,097	$ 6,622,669	$ 7,616,069	$ 8,751,384	$ 5,978,986
2	Gas Interconnect	104,734	182,536	260,338	299,239	351,606	424,919	508,706	304,582
3	Water Interconnect	102,369	178,415	254,461	292,484	343,669	415,327	497,223	297,707
4	Inside the Fence	70,228,858	86,567,817	102,906,776	111,076,256	120,858,132	134,552,760	150,203,762	110,913,480
5	Owners Cost	5,291,997	6,357,449	7,422,901	7,955,626	8,915,301	10,258,847	11,794,327	8,285,207
6	Project Contingency	13,367,433	16,715,183	20,062,933	21,736,808	23,747,067	26,561,431	29,777,846	21,709,814
7	Escalation	7,852,875	9,761,693	11,670,511	12,624,920	14,446,226	16,996,054	19,910,143	13,323,203
8	Total Directs	$ 100,200,470	$ 124,079,654	$ 147,958,838	$ 159,898,430	$ 175,284,670	$ 196,825,406	$ 221,443,391	$ 160,812,980
9									
10	AFUDC	$ 1,858,610	$ 2,468,449	$ 2,468,449	$ 2,468,449	$ 2,468,449	$ 2,468,449	$ 2,468,449	2,381,329
11	Capital Overhead	15,030,070	18,611,948	22,193,826	23,984,765	26,292,701	29,523,811	33,216,509	24,121,947
12	Total Indirects	$ 16,888,680	$ 21,080,397	$ 24,662,275	$ 26,453,214	$ 28,761,150	$ 31,992,260	$ 35,684,958	$ 26,503,276
13	**Total Direct and Indirect Cost**	**$ 117,089,150**	**$ 145,160,051**	**$ 172,621,113**	**$ 186,351,644**	**$ 204,045,820**	**$ 228,817,666**	**$ 257,128,348**	**$ 187,316,256**

	Gross Plant in Service								
	Utility Plant by FERC Account	Projected Capital Balance 9/30/2024	Projected Capital Balance 10/31/2024	Projected Capital Balance 11/30/2024	Projected Capital Balance 12/31/2024	Projected Capital Balance 1/31/2025	Projected Capital Balance 2/28/2025	Projected Capital Balance 3/31/2025	Weighted Average Capital Balance Oct '24 - Mar '25
14	34100 Structures and Improvments	-	-	-	-	-	-	-	-
15	34200 Fuel Holders	-	-	-	-	-	-	-	-
16	34300 Prime Movers	-	-	-	-	-	-	-	-
17	34400 Generators	-	-	-	-	-	-	-	-
18	34500 Accessory Electric Eq	-	-	-	-	-	-	-	-
19	34600 Misc Power Plant Eq	-	-	-	-	-	-	-	-
20	**Total Gross Plant**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

	Accumulated Depreciation								
	Accumulated Depreciation by FERC Account	Projected Capital Balance 9/30/2024	Projected Capital Balance 10/31/2024	Projected Capital Balance 11/30/2024	Projected Capital Balance 12/31/2024	Projected Capital Balance 1/31/2025	Projected Capital Balance 2/28/2025	Projected Capital Balance 3/31/2025	Weighted Average Capital Balance Oct '24 - Mar '25
21	34100 Structures and Improvments	-	-	-	-	-	-	-	-
22	34200 Fuel Holders	-	-	-	-	-	-	-	-
23	34300 Prime Movers	-	-	-	-	-	-	-	-
24	34400 Generators	-	-	-	-	-	-	-	-
25	34500 Accessory Electric Eq	-	-	-	-	-	-	-	-
26	34600 Misc Power Plant Eq	-	-	-	-	-	-	-	-
27	**Total Accumulated Depreciation**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
28	**Total Project Rate Base** (Line 13 + 20 - 27)	**$ 117,089,150**	**$ 145,160,051**	**$ 172,621,113**	**$ 186,351,644**	**$ 204,045,820**	**$ 228,817,666**	**$ 257,128,348**	**$ 187,316,256**

Attachment 1
Schedule 3

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC
Forecasted Expenses for CT Project
Estimates for the Six Month Billing Period October 2024 through March 2025

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Gross Plant in Service								
Line No.	**Utility Plant by FERC Account**		Projected Capital Balance 10/31/2024	Projected Capital Balance 11/30/2024	Projected Capital Balance 12/31/2024	Projected Capital Balance 1/31/2025	Projected Capital Balance 2/28/2025	Projected Capital Balance 3/31/2025	
1	34100 Structures and Improvments		-	-	-	-	-	-	
2	34200 Fuel Holders		-	-	-	-	-	-	
3	34300 Prime Movers		-	-	-	-	-	-	
4	34400 Generators		-	-	-	-	-	-	
5	34500 Accessory Electric Eq		-	-	-	-	-	-	
6	34600 Misc Power Plant Eq		-	-	-	-	-	-	
7	**Total Gross Plant**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Forecasted Depreciation Expense								
	Utility Plant FERC Account	Depreciation Rates	Projected Capital Balance 10/31/2024	Projected Capital Balance 11/30/2024	Projected Capital Balance 12/31/2024	Projected Capital Balance 1/31/2025	Projected Capital Balance 2/28/2025	Projected Capital Balance 3/31/2025	Projected Total Depreciation Expense Oct '24 - Mar '25
8	34100 Structures and Improvments	3.46%	-	-	-	-	-	-	-
9	34200 Fuel Holders	5.32%	-	-	-	-	-	-	-
10	34300 Prime Movers	1.73%	-	-	-	-	-	-	-
11	34400 Generators	1.89%	-	-	-	-	-	-	-
12	34500 Accessory Electric Equipment	6.06%	-	-	-	-	-	-	-
13	34600 Misc Power Plant Equipment	3.10%	-	-	-	-	-	-	-
14	**Total Gross Plant**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Forecasted Property Taxes								
	Utility Plant FERC Account		Projected Capital Balance 10/31/2024	Projected Capital Balance 11/30/2024	Projected Capital Balance 12/31/2024	Projected Capital Balance 1/31/2025	Projected Capital Balance 2/28/2025	Projected Capital Balance 3/31/2025	Projected Total Depreciation Expense Oct '24 - Mar '25
15	Forecasted Property Tax Expense		$ 588	$ 588	$ 588	$ 19,477	$ 19,477	$ 19,477	$ 60,195
16	**Total Projected Expenses** (Line 14 + 15)		**$ 588**	**$ 588**	**$ 588**	**$ 19,477**	**$ 19,477**	**$ 19,477**	**$ 60,195**

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC
Reconciliation of Costs for Gas Costs Tracker
For the Six Month Reconciliation Period

Line No.			
1	Total Actual Net Capital (Att. 1, Sch. 2, Line 37)	$	-
2	Actual Rate of Return for the Reconciliation Period		6.88%
3	Annual Return on Net Capital (Line 1 x Line 2)	$	0
4	Adjusted Return for the billing period (Line 3 * 6/12)	$	0
5	Revenue Conversion Factor (Att 2, Sch 2, Line 12)		1.246846
6	Return on Net Capital Adjusted for Taxes (Line 4 x Line 5)	$	0
7	Return collected during the reconciliatoion period		-
8	Return on Capital Variance (Line 6 - Line 7)	$	60,195
9	Expense Variance - Under / (Over) Collection (Sch 4, Page 3, Line 28)	$	-
10	Total Variance for the Reconciliation Period (Line 8 + Line 9)	$	60,195

	(a)	(b)	(c)	(d)
	Rate Code	Demand Allocation Per Cause No.45772*	Demand Allocation % of Total	Total Demand Allocated Variance Col. c x Total Col. d
11	511	$ 651,361,034	37.67%	$ 0
12	520	1,173,276	0.07%	0
13	521	301,700,945	17.45%	0
14	522	1,097,669	0.06%	0
15	523	166,962,652	9.66%	0
16	524	219,613,694	12.70%	0
17	525	9,298,955	0.54%	0
18	526	189,829,558	10.98%	0
19	531 - Tier 1	117,174,692	6.78%	0
20	532	17,637,102	1.02%	0
21	533	27,109,249	1.57%	0
22	541	5,074,862	0.29%	0
23	542	56,566	0.00%	0
24	543	1,247,539	0.07%	0
25	544	2,392,053	0.14%	0
26	550	7,805,610	0.45%	0
27	555	1,237,835	0.07%	0
28	560	3,323,321	0.19%	0
29	Interdpt	5,094,363	0.29%	0
30	Total	$ 1,729,190,974	100.00%	$ 0

*Demand Allocation per Cause No. 45772 as adjusted and effective for the reconciliation period

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC
Reconciliation of Net Capital for CT Project
For the Six month Reconciliation Period

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Construction Work in Process								
Line No.	**Capital Forecast Detail by Project**	Actual Capital Balance mm/dd/yyyy	Actual Capital Balance mm/dd/yyyy	Actual Capital Balance mm/dd/yyyy	Actual Capital Balance mm/dd/yyyy	Actual Capital Balance mm/dd/yyyy	Actual Capital Balance mm/dd/yyyy	Actual Capital Balance mm/dd/yyyy	Weighted Average Capital Balance mm/dd/yyyy range
1	Electric Interconnect	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Gas Interconnect	-	-	-	-	-	-	-	-
3	Water Interconnect	-	-	-	-	-	-	-	-
4	Inside the Fence	-	-	-	-	-	-	-	-
5	Owners Cost	-	-	-	-	-	-	-	-
6	Project Contingency	-	-	-	-	-	-	-	-
7	Escalation	-	-	-	-	-	-	-	-
8	Total Directs	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9									
10	AFUDC	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-
11	Capital Overhead	-	-	-	-	-	-	-	-
12	Total Indirects	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	**Total Direct and Indirect Cost**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

	Gross Plant in Service								
	Utility Plant by FERC Account	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Weighted Average Capital Balance mm/dd/yyyy range
14	34100 Structures and Improvments	-	-	-	-	-	-	-	-
15	34200 Fuel Holders	-	-	-	-	-	-	-	-
16	34300 Prime Movers	-	-	-	-	-	-	-	-
17	34400 Generators	-	-	-	-	-	-	-	-
18	34500 Accessory Electric Eq	-	-	-	-	-	-	-	-
19	34600 Misc Power Plant Eq	-	-	-	-	-	-	-	-
20	**Total Gross Plant**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

	Accumulated Depreciation								
	Accumulated Depreciation by FERC Account	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Weighted Average Capital Balance m/dd/yyyy range
21	34100 Structures and Improvments	-	-	-	-	-	-	-	-
22	34200 Fuel Holders	-	-	-	-	-	-	-	-
23	34300 Prime Movers	-	-	-	-	-	-	-	-
24	34400 Generators	-	-	-	-	-	-	-	-
25	34500 Accessory Electric Eq	-	-	-	-	-	-	-	-
26	34600 Misc Power Plant Eq	-	-	-	-	-	-	-	-
27	**Total Accumulated Depreciation**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
28	**Total Actual Project Rate Base** (Line 13 + 20 - 27)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC
Reconciliation of Actual Expenses for CT Project
For the Six month Reconciliation Period

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
	Actual Gross Plant in Service								
Line No.	**Utility Plant by FERC Account**		Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	
1	34100 Structures and Improvments		-	-	-	-	-	-	
2	34200 Fuel Holders		-	-	-	-	-	-	
3	34300 Prime Movers		-	-	-	-	-	-	
4	34400 Generators		-	-	-	-	-	-	
5	34500 Accessory Electric Eq		-	-	-	-	-	-	
6	34600 Misc Power Plant Eq		-	-	-	-	-	-	
7	**Total Gross Plant**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	
	Actual Depreciation Expense								
	Utility Plant FERC Account	Depreciation Rates *	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Total Depreciation Expense mm/dd/yyyy range
8	34100 Structures and Improvments	3.46%	-	-	-	-	-	-	-
9	34200 Fuel Holders	5.32%	-	-	-	-	-	-	-
10	34300 Prime Movers	1.73%	-	-	-	-	-	-	-
11	34400 Generators	1.89%	-	-	-	-	-	-	-
12	34500 Accessory Electric Eq	6.06%	-	-	-	-	-	-	-
13	34600 Misc Power Plant Eq	3.10%	-	-	-	-	-	-	-
14	**Total Depreciation Expense**		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
	Actual Property Taxes								
	Utility Plant FERC Account		Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Total Property Tax Expense mm/dd/yyyy range
15	Actual Property Tax Expense		$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Expense Reconciliation								
	Utility Plant FERC Account		Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Actual Capital Balance m/dd/yyyy	Expense Totals mm/dd/yyyy range
16	Total Actual Expenses (Line 14 + 15)		$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	Forecasted Expenses Collected		$ -	$ -	$ -	$ -	$ -	$ -	$ -
18	**Expense Variance** (Line 16 - 17)		**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

*Depreciation Rates per Cause No. 45772

Attachment 2
Schedule 1

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC
Calculation of Electric Weighted Cost of Capital
As of July 2023 using the approved methodology and ROE per Cause No. 45772

	(A)	(B)	(C)	(D)	(E)
Line No.	**Description**	**Amount ($000)**	**Percent of Total**	**Cost in Percent**	**Weighted Average Cost in Percent**
1	Common Equity	$ 4,855,494	52.00%	9.80%	5.10%
2	Long-Term Debt	3,408,944	36.51%	4.76%	1.74%
3	Deferred Income Taxes	1,413,875	15.14%	0.00%	0.00%
4	Post-Retirement Benefits	18,876	0.20%	0.00%	0.00%
5	Prepaid Pension Asset	(427,903)	-4.58%	0.00%	0.00%
6	Customer Deposits	66,990	0.72%	5.63%	0.04%
7	Post-1970 ITC	721	0.01%	7.69%	0.00%
8	Total	$ 9,336,996	100.00%		6.88%

Attachment 2
Schedule 2

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC
Calculation of Revenue Conversion Factor

	(A)	(B)	(C)	(D)
Line No.	**Description**	**Statutory Rate**	**Debt**	**Equity**
1	Gross Revenue Change		100.000000%	100.000000%
2	Public Utility Fee (PUF Rate x Line 1)	0.1163372%	0.1163372%	0.1163372%
3	Subtotal (Line 1 - Line 2)		99.883663%	99.883663%
4	Utility Receipts Tax on Retail Sales (URT Rate x Line 1)	0.000000%	0.000000%	0.000000%
5	Subtotal (Line 3 - Line 4)		99.883663%	99.883663%
6	State Income Tax (see below)	4.900000%	0.000000%	4.894299%
7	Subtotal (Line 5 - Line 6)		99.883663%	94.989363%
8	Federal Income Tax (Federal Income Tax Rate x Line 7) *	21.000000%	0.000000%	19.947766%
9	Subtotal (Line 7 - Line 8)		99.883663%	75.041597%
10	Revenue Conversion Factor (Line 1 / Line 9)		1.001165	1.332594
11	Cost of Capital (Att. 2, Sch.1, Col. E)		1.78%	5.10%
12	Weighted Average Revenue Conversion Factor			1.246846
13	State Income Tax calculations:			
14	Debt:	(Line 4 divided by (1 minus State Income Tax Rate)) minus Line 4		
15	Equity:	State Income Tax Rate x Line 3		

***** Federal income taxes are not applied to the calculation of the Debt component for the Revenue Conversion Factor as Federal income taxes is only inclusive of net income after all costs, including interest.

Attachment 2
Schedule 3

NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC
Estimates for the Six Month Billing Period October 2024 through March 2025

	Demand Allocation					
Line No.	Rate	% Allocation on Revenue*	Demand - Total Revenue	Customer Migration or Other Adjustments	Adjusted Demand - Total Revenue	Adjusted % Allocation on Total Revenue
	Rate 511	37.67%	$ 651,361,034	$ -	$ 651,361,034	37.67%
1	Rate 520	0.07%	1,173,276	-	1,173,276	0.07%
2	Rate 521	17.45%	301,700,945	-	301,700,945	17.45%
3	Rate 522	0.06%	1,097,669	-	1,097,669	0.06%
4	Rate 523	9.66%	166,962,652	-	166,962,652	9.66%
5	Rate 524	12.70%	219,613,694	-	219,613,694	12.70%
6	Rate 525	0.54%	9,298,955	-	9,298,955	0.54%
7	Rate 526	10.98%	189,829,558	-	189,829,558	10.98%
8	Rate 531 - Tier 1	6.78%	117,174,692	-	117,174,692	6.78%
9	Rate 532	1.02%	17,637,102	-	17,637,102	1.02%
10	Rate 533	1.57%	27,109,249	-	27,109,249	1.57%
11	Rate 541	0.29%	5,074,862	-	5,074,862	0.29%
12	Rate 542	0.00%	56,566	-	56,566	0.00%
13	Rate 543	0.07%	1,247,539	-	1,247,539	0.07%
14	Rate 544	0.14%	2,392,053	-	2,392,053	0.14%
15	Rate 550	0.45%	7,805,610	-	7,805,610	0.45%
16	Rate 555	0.07%	1,237,835	-	1,237,835	0.07%
17	Rate 560	0.19%	3,323,321	-	3,323,321	0.19%
18	Interdepartmental	0.29%	5,094,363	-	5,094,363	0.29%
19	**Total**	**100.00%**	**$ 1,729,190,974**	**$ -**	**$ 1,729,190,974**	**100.00%**

*Demand Allocation per Cause No. 45772

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RIDER 595
GENERATION COSTS TRACKER

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as identified in Appendix A.

ADJUSTMENT OF CHARGES FOR GENERATION COSTS

Energy Charges in the Rate Schedules are subject to adjustment to reflect the recovery of costs incurred in connection with the approved construction of a clean energy project. Such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per kWh in accordance with the following:

GCT Factor = (R x D) / S

Where:

"GCT Factor"	is the rate adjustment for each Rate Schedule.
"R"	equals the six (6) month revenue requirement based upon the costs approved by the Commission in a GCT proceeding.
"D"	represents the applicable demand allocation percentage(s) for each Rate Schedule.
"S"	is the six (6) month kWh sales forecast for each Rate Schedule.

GCT FACTOR

The Rate Schedules identified in Appendix A are subject to a GCT Factor. The GCT Factors in Appendix L are applicable hereto and is issued and effective at the dates shown on Appendix L.

The GCT Factors as computed above shall be further modified to allow for the recovery of the GCT revenue requirement reconciled with actual sales and revenues. The GCT Factors per kWh charge for each Rate Schedule are shown on Appendix L.

APPENDIX A
APPLICABLE RIDERS

Rider	Code	Rider Name	Applicable Tariffs
Rider 581	DRR 1	Demand Response Resource Type 1 (DRR 1) – Energy Only	523, 524, 525, 526, 531, 532, 533
Rider 582	EDR-1	Emergency Demand Response Resource (EDR) – Energy Only	523, 524, 525, 526, 531, 532, 533
Rider 583	DSMA	Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA)	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 543, 544, Rider 576
Rider 586	GPR	Green Power Rider	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, and Rider 576
Rider 587	FMCA	Adjustment of Charges for Federally Mandated Costs	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 588	TDSIC	Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 589	EDG	Excess Distributed Generation	511, 520, 521, 522, 523, 524, 525, 526, 532, 533, 541
Rider 594		Adjustment of Charges for Environmental Cost Tracker	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 595	GCT	Generation Costs Tracker	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576

APPENDIX L
GENERATION COSTS TRACKER FACTORS

Sheet No. 1 of 1

As shown in Appendix A, the Generation Costs Tracker ("GCT") Factors in Rates 511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560 and Rider 576, shall be computed in accordance with Rider 595 – Generation Costs Tracker.

Effective for bills rendered during the ________ through ________ 202_ billing cycles, or until a new GCT Factor is approved by the Commission, the GCT Factor shall be:

RATE SCHEDULES

Rate	Charge
Rate 511	A charge of $0.000000 per kWh used per month
Rate 520	A charge of $0.000000 per kWh used per month
Rate 521	A charge of $0.000000 per kWh used per month
Rate 522	A charge of $0.000000 per kWh used per month
Rate 523	A charge of $0.000000 per kWh used per month
Rate 524	A charge of $0.000000 per kWh used per month
Rate 525	A charge of $0.000000 per kWh used per month
Rate 526	A charge of $0.000000 per kWh used per month
Rate 531 Tier 1	A charge of $0.000000 per kWh used per month
Rate 532	A charge of $0.000000 per kWh used per month
Rate 533	A charge of $0.000000 per kWh used per month
Rate 541	A charge of $0.000000 per kWh used per month
Rate 542	A charge of $0.000000 per kWh used per month
Rate 543	A charge of $0.000000 per kWh used per month
Rate 544	A charge of $0.000000 per kWh used per month
Rate 550	A charge of $0.000000 per kWh used per month
Rate 555	A charge of $0.000000 per kWh used per month
Rate 560	A charge of $0.000000 per kWh used per month
Rider 576	See note below

The GCT Factor for Rider 576 will be the GCT Factor associated with the firm service under Rate Schedule 531 Tier 1 being used in conjunction with this Rider.

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Issued Date
__/__/2024~~08/02/2023~~

Effective Date
__/__/2024~~08/04/2023~~

NIPSCO

RIDER 595
GENERATION COSTS TRACKER

TO WHOM AVAILABLE

This Rider shall be applicable to the Rate Schedules as identified in Appendix A.

ADJUSTMENT OF CHARGES FOR GENERATION COSTS

Energy Charges in the Rate Schedules are subject to adjustment to reflect the recovery of costs incurred in connection with the approved construction of a clean energy project. Such charges shall be increased or decreased to the nearest 0.001 mill ($.000001) per kWh in accordance with the following:

GCT Factor = (R x D) / S

Where:

"GCT Factor"	is the rate adjustment for each Rate Schedule.
"R"	equals the six (6) month revenue requirement based upon the costs approved by the Commission in a GCT proceeding.
"D"	represents the applicable demand allocation percentage(s) for each Rate Schedule.
"S"	is the six (6) month kWh sales forecast for each Rate Schedule.

GCT FACTOR

The Rate Schedules identified in Appendix A are subject to a GCT Factor. The GCT Factors in Appendix L are applicable hereto and is issued and effective at the dates shown on Appendix L.

The GCT Factors as computed above shall be further modified to allow for the recovery of the GCT revenue requirement reconciled with actual sales and revenues. The GCT Factors per kWh charge for each Rate Schedule are shown on Appendix L.

APPENDIX A
APPLICABLE RIDERS

Rider	Code	Rider Name	Applicable Tariffs
Rider 581	DRR 1	Demand Response Resource Type 1 (DRR 1) – Energy Only	523, 524, 525, 526, 531, 532, 533
Rider 582	EDR-1	Emergency Demand Response Resource (EDR) – Energy Only	523, 524, 525, 526, 531, 532, 533
Rider 583	DSMA	Adjustment of Charges for Demand Side Management Adjustment Mechanism (DSMA)	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 543, 544, Rider 576
Rider 586	GPR	Green Power Rider	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, and Rider 576
Rider 587	FMCA	Adjustment of Charges for Federally Mandated Costs	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 588	TDSIC	Adjustment of Charges for Transmission, Distribution and Storage System Improvement Charge	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 589	EDG	Excess Distributed Generation	511, 520, 521, 522, 523, 524, 525, 526, 532, 533, 541
Rider 594		Adjustment of Charges for Environmental Cost Tracker	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576
Rider 595	GCT	Generation Costs Tracker	511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560, Rider 576

APPENDIX L
GENERATION COSTS TRACKER FACTORS

Sheet No. 1 of 1

As shown in Appendix A, the Generation Costs Tracker ("GCT") Factors in Rates 511, 520, 521, 522, 523, 524, 525, 526, 531 Tier 1, 532, 533, 541, 542, 543, 544, 550, 555, 560 and Rider 576, shall be computed in accordance with Rider 595 – Generation Costs Tracker.

Effective for bills rendered during the ________ through ________ 202_ billing cycles, or until a new GCT Factor is approved by the Commission, the GCT Factor shall be:

RATE SCHEDULES

Rate	Charge
Rate 511	A charge of $0.000000 per kWh used per month
Rate 520	A charge of $0.000000 per kWh used per month
Rate 521	A charge of $0.000000 per kWh used per month
Rate 522	A charge of $0.000000 per kWh used per month
Rate 523	A charge of $0.000000 per kWh used per month
Rate 524	A charge of $0.000000 per kWh used per month
Rate 525	A charge of $0.000000 per kWh used per month
Rate 526	A charge of $0.000000 per kWh used per month
Rate 531 Tier 1	A charge of $0.000000 per kWh used per month
Rate 532	A charge of $0.000000 per kWh used per month
Rate 533	A charge of $0.000000 per kWh used per month
Rate 541	A charge of $0.000000 per kWh used per month
Rate 542	A charge of $0.000000 per kWh used per month
Rate 543	A charge of $0.000000 per kWh used per month
Rate 544	A charge of $0.000000 per kWh used per month
Rate 550	A charge of $0.000000 per kWh used per month
Rate 555	A charge of $0.000000 per kWh used per month
Rate 560	A charge of $0.000000 per kWh used per month
Rider 576	See note below

The GCT Factor for Rider 576 will be the GCT Factor associated with the firm service under Rate Schedule 531 Tier 1 being used in conjunction with this Rider.