STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

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

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

PUBLIC'S EXHIBIT NO. 4

TESTIMONY OF OUCC WITNESS CYNTHIA M. ARMSTRONG

JANUARY 20, 2023

Respectfully submitted,

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TESTIMONY OF OUCC WITNESS CYNTHIA M. ARMSTRONG
CAUSE NO. 45772
NORTHERN INDIANA PUBLIC SERVICE COMPANY

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is Cynthia M. Armstrong, and my business address is 115 W. Washington St., Suite 1500 South, Indianapolis, IN, 46204.

Q: By whom are you employed and in what capacity?

A: I am employed as a Chief Technical Advisor in the Electric Division for the Indiana Office of Utility Consumer Counselor ("OUCC"). A summary of my qualifications can be found in Appendix A.

Q: Have you previously provided testimony to the Indiana Utility Regulatory Commission ("Commission")?

A: Yes.

Q: What have you done to evaluate issues presented in this Cause?

A: I read and reviewed materials presented in this docket, including Northern Indiana Public Service Company's ("NIPSCO," "Company," or "Petitioner") petition, pre-filed verified direct testimony and exhibits, and responses to data requests. I also reviewed materials NIPSCO presented in Cause Nos. 45700 and 45797 regarding ash pond closures at the Michigan City and Schahfer Generating stations to comply with the Coal Combustion Residuals ("CCR") Rule and the Resource Conservation and Recovery Act ("RCRA").

Q: What is the purpose of your testimony in this proceeding?

A: The purpose of my testimony is to address NIPSCO's request for a Variable Cost

Tracker ("VCT"), exclusion of CCR closure costs from demolition costs and depreciation, and to modify accounting for joint venture reserves.

Q: How is your testimony organized?

A: First, I describe NIPSCO's request for the VCT, provide a regulatory background for similar utility requests, identify issues with NIPSCO's estimate of VCT costs, and explain why the VCT is unnecessary and should be denied. Next, I explain the OUCC's position that NIPSCO's costs to close CCR disposal units should be recovered through traditional means instead of in a tracking mechanism. Finally, I explain the OUCC's agreement with NIPSCO's request to consolidate the reserve amounts held at each individual joint venture into one reserve account at the Company level. My testimony supports the testimonies of OUCC witnesses Michael Eckert, Brian Latham, David Garrett, Wes Blakley, Kaleb Lantrip, and Mark Garrett.

Q: To the extent you do not address a specific item or adjustment, should that be construed to mean you agree with NIPSCO's proposal?

A: No. Excluding any specific adjustments or amounts proposed by NIPSCO from my testimony does not indicate my approval of those adjustments or amounts, but rather that the scope of my testimony is limited to the specific items addressed herein.

II. VARIABLE COST TRACKER

Q: Please summarize NIPSCO's request for the VCT.

A: NIPSCO proposes a new rider, Rider 594, to track the non-labor variable costs of its coal-fired generation. The VCT, as proposed, would be filed on a semi-annual basis and based on actual expenses, with the first filing to occur in March 2024.

The expenses included in the VCT include six categories of O&M expenses. NIPSCO removed these costs from the test year for the purposes of calculating the revenue requirement in this Cause, instead proposing 100% of these costs should be tracked in the VCT. The six categories to be recovered via the VCT and their associated estimated costs are:

- Generation maintenance activity: $34,094,580;
- Planned outages: $11,893,401;
- Forced outages: $4,648,497;
- Variable chemicals: $21,365,434;
- Nontrackable fuel handling: $19,714,059; and
- NOx allowances: $9,960,000.

NIPSCO's proposed VCT is estimated to recover $101,675,971 in non-labor O&M expenses during its first year.[1]

Q: Is NIPSCO's request for a VCT reasonable?

A: No. First, allowing NIPSCO to track these costs discourages it from efficiently managing costs. Second, the proposed VCT tracks costs that are likely to increase over the short term, while costs likely to decrease or increase revenues will not be tracked. Third, the expansive nature of the VCT shifts the risk of operating coal-fired generation from NIPSCO to its customers. OUCC witness Latham speaks to NIPSCO's reduction in risk if the VCT is approved. Finally, completely removing VCT costs from the test year hides the full impact of NIPSCO's requested rate increase from ratepayers.

[1] Direct Testimony of NIPSCO Witness Kevin J. Blissmer, pp. 34-35.

Q: Has the Commission previously approved similar trackers?

A: No. While the Commission has approved tracking of some of the cost categories NIPSCO includes in its proposed VCT, it has not approved a tracker as broad as the VCT. In Cause No. 43839, Vectren South Electric ("VSE") requested a Variable Production Cost ("VPC") tracker, including costs for ammonia and other chemicals, catalysts, ash and gypsum disposal, and fuel handling. The Commission denied this tracker. In its findings, the Commission stated:

> This Commission has previously allowed trackers for several types of expenses. These include the previously mentioned FAC process, environmental cost recovery trackers, demand side management ("DSM") trackers, and MISO cost trackers. Vectren South believes that the chemical and catalyst costs it that it has incurred are volatile, substantial, and largely outside of the control of the utility. These three qualities for an expense to be tracked are basic guidelines to follow, they are not rigid principles requiring the creation of a tracker. We believe the causes for determining if an expense or revenue is appropriate for tracking are often times situational. While we have approved a number of trackers in the past, we acknowledge Dr. Dismukes's warnings. Revenue or cost trackers tend to make utilities less accountable for their actions because they are less incented to streamline costs or operations. We are also concerned that the proliferation of trackers in the electric industry may result in utilities unreasonably extending the time between rate cases. If they can recover the majority of their variable costs through trackers, they have no incentive to come before the Commission and account for other, non-tracked, decreasing costs or increasing revenues.
>
> Based upon the discussion above, we do not find Vectren South's VPC tracker proposal to be reasonable. While we acknowledge the possibility that chemical and catalyst costs may be volatile in the future, we find it is reasonable to confirm that possibility before moving towards tracking such costs. As Vectren South has embedded an amount for this expense into its base rates it will receive timely recovery of a representative level of costs. We do not

> foreclose the future consideration of such a tracker should the potential volatility be realized and established with evidence.[2]

Since the Commission issued this order, Indiana Michigan Power Company ("I&M") and Duke Energy Indiana ("DEI") have requested and received approval to track environmental consumables and emission allowances. In both situations, the Commission ruled I&M and DEI had shown variability in these expenses and determined this volatility was based on factors outside the control of the utility.[3] In DEI's case, the Commission distinguished DEI's request from its finding in Cause No. 43839:

> The evidence presented established that DEI's reagent expense is and will continue to be variable, and there was no evidence offered to rebut that variability. The establishment of reagent expense variability distinguishes this from the rationale in the Commission's April 27, 2011 Order in Cause No. 43839, in which variability was uncertain.[4]

NIPSCO's proposed VCT includes some of the environmental expenses the Commission approved DEI and I&M to track. However, by including general maintenance, planned outage, and forced outage costs, the VCT is more expansive than Vectren's proposed VPC tracker the Commission rejected in Cause No. 43839. NIPSCO's VCT would track more than half of its total electric operations O&M

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[2] *In re S. Ind. Gas & Elect. Co. d/b/a Vectren Energy Deliv. of Ind., Inc.*, Cause No. 43839, Final Order, pp. 64-65. (Ind. Util. Regul. Comm'n Apr. 27, 2011).
[3] *In re Ind. Mich. Pwr. Co.*, Cause No. 45235, Final Order, pp. 99-100. (Ind. Util. Regul. Comm'n Mar. 11, 2020).
In re Duke Energy Ind., LLC, Cause No. 45253, Final Order, p. 140. (Ind. Util. Regul. Comm'n June 29, 2020).
[4] *Id.*

budgeted for 2023,[5] which significantly shifts the risk of increased O&M costs from NIPSCO to its ratepayers.

Q: Are all costs that NIPSCO proposed to track in the VCT volatile?

A: No, not all costs tracked in the VCT appear to be volatile. NIPSCO's actual and budgeted general maintenance and forced outage costs do not appear to vary materially from year to year.[6] Although planned outage costs appear to vary significantly when comparing actual 2021 expenditures to 2022 and 2023 budgeted costs, the cyclical nature of outage costs can be normalized by averaging these costs over a historical period.[7]

Q: How could the VCT discourage NIPSCO from managing its generating costs efficiently?

A: If NIPSCO can track most of its coal-fired generating O&M costs, it is less incentivized to undertake potentially cost-saving investments or activities that will reduce O&M.

Q: Do you have any examples where NIPSCO may be less incentivized to undertake potentially cost-saving investments or activities that reduces O&M costs?

A: Yes. In February 2022, the EPA proposed the Good Neighbor Plan to prevent downwind states contributing to upwind states' non-attainment of the 2015 revisions to the Ozone National Ambient Air Quality Standards ("NAAQS"). In addition to targeting other industrial sources not currently subject to the Cross State Air Pollution Rule ("CSAPR"), the rule significantly reduces NOx Seasonal emission budgets for fossil-fuel fired power plants in 25 states beginning in 2023.

[5] Petitioner's Exhibit No. 3, Attachment 3-C-S2, OM 2 Matrix, p.[.1].
[6] Petitioner's Confidential Exhibit No. 22-S2 (Redacted), Workpapers OM 2A and OM 2C.
[7] Petitioner's Confidential Exhibit No. 22-S2 (Redacted), Workpaper OM 2B.

These budgets will be further reduced in 2026 at a level that requires all units to install and continuously operate selective catalytic reduction ("SCR") controls during the Ozone Season.[8] The EPA finalized modifications to allowances allocated to existing coal-fired units in affected states in August 2022, which results in NOx emission allowance reductions beginning in the 2023 Ozone Season.[9] Due to these changes to the CSAPR trading programs, Seasonal NOx allowance prices have skyrocketed over the past year, reaching a record high of $48,000/ton.[10] While Seasonal NOx prices have decreased since this peak, they remain at elevated levels.

While proceeds from the sale of Annual NOx or SO_2 allowances will not generate the revenue necessary to completely offset other O&M costs, NIPSCO could sell excess Annual NOx or SO_2 allowances. As of the end of 2021, NIPSCO held over 17,000 NOx Annual allowances and 177,000 CSAPR SO_2 allowances in inventory.[11] However, finding a prospective buyer of allowances can take time and money, and NIPSCO would likely pay brokerage fees to complete such a sale. If NIPSCO can track coal-fired generation O&M, it has less incentive to exhaust company resources monetizing its excess emission allowances.

Q: Have you identified any costs that may decrease that will not be tracked in the VCT?

A: Yes. While the VCT would track materials and supplies expense related to coal-fired generation, NIPSCO does not plan to track changes in materials and supplies

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[8] 87 <u>Federal Register</u> 20036-20216.
See also, *Fact Sheet: Proposed Good Neighbor Plan for the 2015 Ozone NAAQS*. Available at: https://www.epa.gov/csapr/good-neighbor-plan-2015-ozone-naaqs.
[9] 87 FR 52473-52481.
[10] Martin, C. (Sept. 26, 2022) *Seasonal NOx prices fall after summer surge*. Argus. https://www.argusmedia.com/en/news/2374451-seasonal-nox-prices-fall-after-summer-surge.
[11] OUCC Attachment CMA-1, Response to OUCC DR 17-009.

inventory embedded in base rates related to the O&M costs it intends to track.[12] Since NIPSCO is planning to retire its coal-fired generation, the Company is likely to use the remaining parts and supplies without acquiring additional replacement parts or supplies. If O&M costs are tracked, decreases in inventory and the associated decreased return on inventory should also be tracked.

Another cost that could decrease as coal-fired generation shuts down is labor expense, as fewer employees are needed to run NIPSCO's replacement generation. To be clear, the OUCC is not advocating for NIPSCO to track labor expense, but I am noting this as a non-tracked expense that could decrease as coal-fired units are retired.

Q: Have you identified any problems with NIPSCO's estimate of VCT costs?

A: Yes. First, it appears NIPSCO is not following FERC accounting rules with respect to recording emission allowance costs and inventory. My second concern is that NIPSCO could be tracking O&M related to its gas generating units in the VCT. Finally, the OUCC has concerns that some costs NIPSCO proposes to track in the VCT are attributable to the early retirement of Schahfer Units 14 and 15 caused by the July 2020 fire at the Schahfer Generating Station.

Q: Please explain the problem of NIPSCO not recording monthly emission allowance costs according to FERC rules.

A: The FERC Uniform System of Accounts ("USoA") requires issuances from inventory included in Account 158.1 (Allowance Inventory) and 158.2 (Allowances Withheld) to be accounted for using a monthly weighted-average

[12] OUCC Attachment CMA-2, NIPSCO's Responses to OUCC DRs 17-005.

method of cost determination, and expensed monthly based on each month's emissions.[13] When I reviewed I&M's and DEI's emission allowance trackers in the past, both utilities have accounted for emission allowance expense based on the monthly weighted-average inventory cost.[14] When asked for its monthly inventory balance calculations for Annual NOx, Seasonal NOx, and SO_2 allowances, NIPSCO responded that it did not track inventory balances on a monthly basis, nor does it track the weighted average cost of the inventory ("WACI").[15] This has not been as much of an issue in the past, as NIPSCO could rely solely on the zero cost allowances allocated to its units for compliance. However, NIPSCO is likely to be short on seasonal NOx allowances for the next several years and will need to purchase allowances to cover its Ozone Season NOx emissions.

Without calculating monthly inventory costs and allowance consumption, it would be difficult to appropriately track allowance expense at the detail necessary to support NIPSCO's VCT calculation. Additionally, it is difficult to fairly allocate emission allowance costs to each generating unit, which is necessary because O&M attributed to NIPSCO's gas units would not be tracked in the VCT. If NIPSCO does not calculate the WACI and expense emission allowance consumption monthly, it is easier for the Company to allocate only zero-cost allowances to the gas units while charging purchased allowance costs to the coal-fired units. Finally, while NIPSCO may plan to only purchase enough allowances to cover annual emissions,

[13] 18 CFR Part 101, Instruction 21.
[14] For I&M, see Cause No. 43992 and its subsequent tracker filings. For DEI, see Cause No. 42061 ECR 10 and subsequent tracker filings. Please note emission allowance inventory calculations were Confidential exhibits and usually included in a Standard Audit Package.
[15] OUCC Attachment CMA-1, NIPSCO's Response to OUCC DR 17-009.

there will likely be some unused allowances that will carry over into the next year. In this situation, it would be inappropriate for the Company to charge the full cost of allowance purchases to that compliance year, as not all allowances would have been consumed during the year. Calculating monthly inventory costs and emission allowance consumption expense allows these costs to be tracked into the following compliance year until they are fully consumed.

Q: Why are you concerned NIPSCO could track gas unit costs in the VCT?

A: NIPSCO does not account for all VCT cost categories by unit. Generation maintenance activity, forced outages, and emission allowance costs are tracked at the station level.[16] The Schahfer Generating Station has two gas units, 16A and 16B. Although these units are smaller and have fewer O&M costs compared to Units 17 and 18, the VCT is likely to contain O&M costs associated with these units if NIPSCO accounts for these O&M categories at the station level. Further, it would be difficult for the IURC, the OUCC, and any interested parties to discern and verify these O&M costs are solely attributable to coal-fired generation when reviewing VCT filings.

NIPSCO has already informed the OUCC that it discovered 52 NOx Emission Allowances were included for Schahfer Units 16A and 16B and Sugar Creek in the VCT, amounting to $1,560,000. NIPSCO stated it will increase its base rate request and decrease its VCT by this amount in its rebuttal filing.[17]

Q: Why is the OUCC concerned that some VCT costs are linked to the early retirement of Schahfer Units 14 and 15?

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[16] OUCC Attachment CMA-3, NIPSCO's Response to OUCC Data Request 17-001.
[17] *Id.*

A: As indicated above, the EPA's modifications to the CSAPR trading program significantly reduces the cap on Seasonal NOx emissions and resulted in increased demand for NOx allowances. This increase in demand has led to a surge in Seasonal NOx allowance prices. Beginning in 2026, this cap will be further reduced to a level where units must either have SCR units installed or must significantly reduce operation. Schahfer Units 17 and 18 do not have SCR units, and they must rely on NIPSCO's other units with more stringent NOx controls for compliance. NIPSCO would not be incurring these increased NOx allowance costs if it was not continuing to operate Schahfer Units 17 and 18 past 2023 to address reliability concerns resulting from delays in constructing its new renewable generation projects.

On the other hand, Schahfer Units 14 and 15 had more efficient NOx removal controls. Schahfer Unit 14 had an SCR system installed, and Schahfer Unit 15 used Selective Non-Catalytic Reduction ("SNCR") to target NOx emissions. Had the July 2020 fire not occurred, Schahfer Units 14 and 15 would have been available to fill NIPSCO's reliability need after 2023, and NIPSCO would likely not need to purchase additional NOx Seasonal Allowances to comply with tightened CSAPR requirements. Additionally, due to the changes to the updated Steam Electric Generation Effluent Limitation Guidelines ("ELGs") I discuss below, there was a possibility that these units could have remained available for NIPSCO to operate until 2028 without installing an additional FGD wastewater treatment system as Schahfer Units 14 and 15 had closed-loop systems in place to address bottom ash transport water.

OUCC witness Michael Eckert discusses the OUCC's position that NIPSCO's imprudent actions lead to this fire and costs associated with them should be denied. In addition to Mr. Eckert's recommendation to deny certain costs associated with the Schahfer early retirement, I recommend denial of NIPSCO's recovery of NOx Seasonal allowance costs. This has the effect of reducing the OUCC's recommended amount of VCT-related costs embedded in in the test year by $9.96 million.

Q: OUCC Witness Brian Latham expresses a concern the VCT could encourage NIPSCO to delay retirement of its remaining coal units. Could NIPSCO operate its remaining coal-fired units past their current retirement dates?

A: Yes, but only with respect to Michigan City Unit 12. Schahfer Units 17 and 18 are unlikely to continue operation past 2025.

Q: Why are Schahfer Units 17 and 18 unlikely to operate past 2025?

A: They do not currently meet updated ELGs. NIPSCO would have to make substantial investments to treat Flue Gas Desulfurization ("FGD") wastewater and bottom ash ("BA") transport water from both units to continue operating in compliance with environmental regulations beyond 2025. ELG compliance was one of the main drivers for NIPSCO's previous plan to retire these units in 2023, as this was the latest compliance date possible for meeting effluent standards. Since NIPSCO's last rate case, the EPA finalized the 2020 Steam Electric Reconsideration Rule, which extended the date to comply with new effluent limitations to December 31, 2025.[18] The final rule also allowed units committing to permanently cease coal combustion by 2028 to avoid such investments if the unit

[18] 40 CFR §423.13.
85 Fed. Reg. 64717-64718.

met limitations for Total Suspended Solids ("TSS") in FGD wastewater and BA transport water. However, to qualify for the Permanent Cessation of Coal subcategory, NIPSCO was required to file a notice with the EPA and IDEM by October 13, 2021.[19] NIPSCO does not appear to have made such a filing regarding Schahfer. In fact, NIPSCO notified IDEM on October 13, 2021, that Schahfer Units 14 and 15 had been retired, but that continuation of its current NPDES permit was required to support operation of Units 17 and 18 until Schahfer's planned retirement in 2023.[20] The lead time necessary to design, permit, procure equipment for, and construct both dry BA handling and FGD wastewater treatment systems for Units 17 and 18 is insufficient to meet a December 31, 2025, compliance date.

Continuing to operate Units 17 and 18 beyond 2025 would also complicate Schahfer's compliance with the CCR Rule. The CCR Part A Rule requires all unlined CCR surface impoundments, CCR units showing groundwater exceedances for multiple constituents, and CCR units failing the aquifer location restriction to cease receiving CCR by April 11, 2021, unless a source is seeking a compliance extension.[21] A CCR impoundment may continue to receive CCR and non-CCR waste streams if the facility will cease operation of the coal-fired boilers and complete closure by no later than October 17, 2023, for impoundments 40 acres or smaller and by October 17, 2028, for impoundments larger than 40 acres.[22]

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[19] 40 CFR §423.19(f)(1).
85 Fed. Reg 64722.

[20] OUCC Attachment CMA-4, IDEM Virtual File Cabinet ("VFC") Document #83305291 (October 13, 2021). Document is available at https://vfc.idem.in.gov/DocumentSearch.aspx.

[21] 85 Fed. Reg., 53561-53563.

[22] 85 FR, 53564. 257 CFR §106(f)(2).

NIPSCO submitted its initial CCR Part A Demonstration on October 30, 2020, where it indicated Schahfer would permanently cease combusting coal by May 2023.[23] NIPSCO has since filed an addendum indicating it was necessary to continue operating Schahfer Unit 17 and 18 until 2025 for reliability purposes.[24] Even if NIPSCO was able to make the necessary wastewater retrofits in time to continue operating Units 17 and 18 beyond 2025, the Company would have to undertake additional studies and modify its CCR Part A extension request. NIPSCO could encounter logistical constraints with managing the closure of its remaining CCR impoundments while constructing new wastewater treatment facilities onsite.

Q: Why could Michigan City Unit 12 continue to operate past 2028?

A: Michigan City Unit 12 has pollution controls that favorably position it to comply with currently-known environmental compliance deadlines. Unit 12 has a dry FGD, which generates minimal wastewater and dry bottom ash handling, so the facility currently meets the updated ELGs. Unit 12 also has an SCR unit for NOx control, which allows it to comply with future NOx and ozone regulations. However, NIPSCO faces pressure from environmental groups and stakeholders to address its facilities' contribution to climate change. Future regulations targeting CO_2 emissions from fossil-fueled generation could impede Unit 12's ability to operate after its planned 2028 retirement date.

Q: What does the OUCC recommend regarding NIPSCO's request for the VCT?

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[23] https://www.epa.gov/coalash/coal-combustion-residuals-ccr-part-implementation.

[24] NIPSCO R.M. Schahfer Generating Station Demonstration of Site-Specific Alternative Deadline to Initiate Closure of CCR Surface Impoundment Due to Permanent Cessation of Coal-Fired Boilers by a Date Certain—Addendum 2. (August 2022.) https://www.nipsco.com/our-company/about-us/our-environment/ccr-rule-compliance.

A: For the reasons OUCC witness Latham and I provide, the OUCC recommends denial of NIPSCO's request for the VCT. The forecasted costs should be included in NIPSCO's overall rate request and adjusted once NIPSCO reconciles actual test year costs. When considering my recommendation to deny NIPSCO's recovery of $9.96 million in NOx Seasonal emission allowance costs, the OUCC's recommended test year amount to be embedded in base rates is $91,715,971. OUCC Witness Mark Garrett makes this adjustment in his schedules.

III. <u>CCR CLOSURE COSTS</u>

Q: Is NIPSCO seeking recovery of any ash pond closure costs in this Cause?

A: Yes, it is in the demolition costs used to determine its proposed depreciation rates, but only for units not subject to the CCR Rule. NIPSCO has excluded CCR-rule related pond closure costs in demolition costs.[25] The Company intends to seek recovery of CCR closure costs via Ind. Code ch. 8-1-8.4, the Federally Mandated Requirements statute ("the FMR statute"),[26] and currently has two pending cases before the Commission for CCR unit closures at the Michigan City Generating Station (Cause No. 45700) and the Schahfer Generating Station (Cause No. 45797). NIPSCO has included demolition costs for three non-CCR ponds at Michigan City that it is also requesting to recover as a federally mandated project in Cause No. 45700. NIPSCO acknowledges that if its relief in Cause No. 45700 is granted, it

[25] Blissmer Direct, pp. 9-10.
[26] Blissmer Direct, p. 9, ll. 10-15.

would need to remove these costs from decommissioning to avoid double counting.[27]

NIPSCO is also adjusting rate base to include the deferred 20% portion of the Federally Mandated Cost Adjustment ("FMCA") costs incurred in connection with the Ash Pond Compliance Project it is currently seeking approval for in Cause No. 45700. Adjustment RB-11 increases the regulatory asset balance by $398,949 to reflect the FMCA deferral.[28] Accordingly, NIPSCO also adjusts amortization expense to include annual amortization of the FMCA regulatory asset for the deferred 20% portion. AMTZ-6 increases amortization expense by $153,661.[29] OUCC Witness Kaleb Lantrip addresses the FMCA adjustments in his testimony.

Q: Does the OUCC agree with NIPSCO's exclusion of CCR-Rule related ash pond closures?

A: No. The OUCC's position is that these costs should be recovered in a traditional manner just like other costs of removal. There was always an expectation that NIPSCO's ash ponds would have to close, and the costs for plant retirement or asset closure activities have traditionally been accounted for in depreciation. The actual costs to close the ponds may increase as time progresses and regulations change, but the Company has the opportunity to adjust them with every rate case. It is an unnecessary and wasteful use of the Commission's and the OUCC's resources to track these costs when the Company can receive appropriate recovery of them by

[27] Blissmer Direct, p. 10, ll. 10-17, through p. 11, l. 1.
[28] Blissmer Direct, pp. 16-17.
[29] Direct Testimony of Petitioner's Witness Jennifer L. Shikany, pp. 71-72.

including them in base rates now. Ratepayers will also benefit from NIPSCO avoiding additional filing costs recovered in rates.

The OUCC presented significant issues with NIPSCO's requested recovery of CCR pond closures under the FMR statute in Cause No. 45700. These issues would be resolved if NIPSCO were to include the future closure costs in decommissioning costs and reflect previously incurred costs in accumulated depreciation in this Cause.

Q: What issues did the OUCC raise in Cause No. 45700 regarding NIPSCO's proposed recovery of the Michigan City Ash Pond Compliance Project under the FMR statute?

A: In Cause No. 45700, NIPSCO requested recovery of "federally mandated costs", historically recovered through depreciation, that NIPSCO omitted from demolition costs and the resulting depreciation rate calculation in Cause No. 45159. As I explained in my testimony in Cause No. 45700, NIPSCO cannot recover any costs or losses incurred prior to the Commission issuing an order approving the CPCN. The OUCC based its testimony on an Indiana Supreme Court decision regarding DEI's recovery of past CCR unit closure costs.

Q: Please explain the Supreme Court decision you are referring to.

A: In *Indiana Office of Utility Consumer Counselor v. Duke Energy Ind., LLC* ("*OUCC v. DEI*"),[30] the OUCC appealed the Commission's Final Order in DEI's rate case in Cause No. 45253, challenging the allowed recovery of DEI's past CCR closure costs as a regulatory asset included in DEI's rate base. DEI did not seek prior approval of CCR closure costs before they were incurred and recorded in a

[30] *Ind. Ofc. of Util. Consumer Couns. v. Duke Energy Ind., LLC*, 186 N.E.3d 266 (Ind. 2022), *reh'g denied*.

regulatory asset. DEI had also included ash pond closure costs in decommissioning studies used in setting depreciation rates in its previous rate case. The Court found recovery of coal ash costs incurred before the Commission issued its Cause No. 45253 order in June 2020 was unlawful because it constituted retroactive ratemaking.

> Applying here the principle that a utility cannot recover unforeseen past losses, we hold that the commission's order is retroactive ratemaking. This is so because the commission established Duke's rate in 2004, which governed the period from 2010 until the current order in June 2020. Duke acknowledges that the commission already adjudicated depreciation rates in its 2004 rate order. The actual costs turned out to be more than Duke expected. Duke then sought re-adjudication through its 2019 rate case. But we have already held that utilities may not re-adjudicate costs for a time period governed by a prior order…Here the commission violated the bar against retroactive ratemaking by re-adjudicating in 2020 coal-ash costs governed by its 2004 rate order.

OUCC v. DEI, 186 N.E.3d at 270.

When examining arguments regarding pre-authorization of CCR closure costs, the Court also discussed the Federal Mandate Statute (Ind. Code ch. §8-1-8.4).

> [H]ad Duke properly sought recourse under Indiana's federal mandate statute, I.C. ch. 8-1-8.4, the result may have been different, at least for the costs Duke incurred to comply with the EPA's 2015 rulemaking. This statute permits utilities to recover costs incurred due to changes in federal regulations. Although we have not yet interpreted the statute, we note it is framed in the future tense and speaks of "projected" costs for "proposed" projects, see *id.* §§ 8-1-8.4-6(a), 6(b), 6(b)(1), 7(b)(1), 7(b)(2), which would seem to require commission approval **before** a utility incurs the costs. Where another statute authorizes the commission's action, and specifically contemplates prior approval for certain types of expenses, the statutory prohibition against retroactive ratemaking may not apply. Here, however, Duke did not seek prior approval of its coal-ash costs. Thus what governs here is not the federal mandate statute but the prohibition against retroactive ratemaking.

Id. (emphasis in original).

Although the Court's decision did not center on the interpretation of the federal mandate statute, it indicated Commission approval was a prerequisite to recover federally mandated costs, and that the statute is "framed in the future tense and speaks of 'projected' costs for 'proposed' projects[.]" *Id.*

Q: Has NIPSCO recovered costs associated with CCR pond closures in past rate cases?

A: Yes. While they were not specifically tied to the CCR Rule, NIPSCO has included costs to close ash ponds in previous decommissioning cost studies in the following rate cases.

- Cause No. 43969: NIPSCO's depreciation witness John J. Spanos based the final net salvage of steam production units on decommissioning cost studies offered in Cause No. 43526.[31] The costs to restore the Schahfer, Bailly, and Michigan City Generating sites to industrial conditions included costs to drain, grade, and cap on-site ash settling ponds.[32] The final cover system described in these studies is identical to the final cover system required under "the closure in place" ("CIP") option under the CCR Rule. Environmental remediation costs (which included asbestos, lead paint, arsenic, and mercury removal alongside closing ash ponds and coal yards[33]) were $56,686,616 for Schahfer, $18,130,257 for Bailly, and $14,667,806 for Michigan City.[34] The Commission approved a Settlement Agreement between NIPSCO, the OUCC, and several Intervenors, where the parties agreed to Mr. Spanos' recommended depreciation accrual rates with a pro-forma depreciation expense reduction of $4.9 million.[35]

- Cause No. 44688: NIPSCO's depreciation witness John J. Spanos based the final net salvage of steam production units on decommissioning cost studies offered by witness Victor F. Ranaletta.[36] The costs to restore the Schahfer, Bailly, and Michigan City Generating sites to industrial conditions included

[31] Cause No. 43969, Direct Testimony of John J. Spanos, p. 11, ll. 10-16.
[32] Cause No. 43526, Direct Testimony of Victor F. Ranaletta, Petitioner's Exhibits VFR-2, pp. 3-4; VFR-3, pp. 3-4; and VFR-7, pp. 3-4.
[33] Cause No. 43526, Ranaletta Direct, p. 7, ll. 8-10.
[34] Cause No. 43526, Petitioner's Exhibits VFR-2, Table A.1., VFR-3, Table A.1., and VFR-7, Table A.1.
[35] Cause No. 43969, Final Order (Approved December 11, 2011), Settlement Agreement, pp. 5-6.
[36] Cause No. 44688, Direct Testimony of John J. Spanos, pp. 14-15.

costs to drain, grade, and cap on-site ash settling ponds.[37] The final cover system described in these studies is identical to the final cover system required under "the closure in place" ("CIP") option under the CCR Rule. Environmental remediation costs (which included asbestos, lead paint, arsenic, and mercury removal alongside closing ash ponds and coal yards[38]) were $87,511,804 for Schahfer, $35,155,557 for Bailly, and $26,008,438 for Michigan City.[39] The Commission approved a Settlement Agreement between NIPSCO, the OUCC, and several Intervenors, where the parties agreed to Mr. Spanos' recommended depreciation accrual rates with a pro-forma depreciation expense reduction of $17.3 million.[40]

In NIPSCO's rebuttal in Cause No. 45700, the Company estimated it had recovered approximately $2.9 million associated with general ash pond closure costs at Michigan City as of December 2021 and reduced the Ash Pond Compliance Project costs to reflect this estimated amount.[41]

Q: In Cause No. 45700, you testified that NIPSCO's recovery of any losses associated with closure costs prior to the Commission issuing a Federally Mandated CPCN constitutes retroactive ratemaking.[42] Why would retroactive ratemaking not apply to the OUCC's recommendations in this case?

A: This is a general rate case where the Commission can examine NIPSCO's costs and revenues to determine the appropriate rates that will allow the Company to safely and reliably operate while earning a reasonable return. Even if NIPSCO previously removed or omitted CCR closure costs in determining its depreciation rates, this is the appropriate forum to include these costs, adjust depreciation rates, and reduce accumulated depreciation for any expenditures NIPSCO has made to date on CCR unit closures. The OUCC's recommendation avoids retroactive ratemaking issues

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[37] Cause No. 44688, Direct Testimony of Victor F. Ranaletta, Attachment 9-A, p. 14, Attachment 9-B, pp. 12-13, and Attachment 9-C, pp. 13-14.
[38] *Id*., p. 11, ll. 6-9.
[39] *Id*., Attachment 9-A, p. 18; Attachment 9-B, p.16; and Attachment 9-C, p. 17.
[40] Cause No. 44688, Final Order (Approved July 18, 2016), Settlement Agreement, pp. 9-10.
[41] Cause No. 45700, Rebuttal testimony of NIPSCO Witness Gunnar J. Gode, p. 2.
[42] Cause No. 45700, Direct testimony of OUCC witness Cynthia M. Armstrong, p. 2, ll. 14-17.

by recognizing the status of NIPSCO's CCR disposal unit retirements as of the end of the test year without recovering their discrete impacts to NIPSCO's rate base in-between rate cases.

Q: Would the impact of the OUCC's recommendation for CCR closure costs increase depreciation expense?

A: Yes, but NIPSCO's customers will experience this impact whether it is in base rates or a federally mandated cost tracker. It is better to reflect these costs in base rates as it better aligns recovery from ratepayers receiving the benefits from CCR disposal facilities. Additionally, adjusting depreciation now to include CCR closure costs will avoid the additional regulatory costs associated with tracker filings.

Q: Are there other utilities that recover CCR closure costs through base rates and not through a Federally Mandated cost tracker?

A: Yes. Indiana Michigan Power Company ("I&M") and AES Indiana currently recover their CCR closure costs through base rates. I&M has recorded asset retirement obligations ("AROs") for the Rockport Generating Facility's ash ponds and recovers accretion expense on ash pond AROs through O&M.[43] AES Indiana[44] included the costs of ash pond closures in the decommissioning costs[45] to determine depreciation rates in its previous rate case, Cause No. 45029. [46]

Q: Does the OUCC take issue with NIPSCO's inclusion of deferred FMCA costs in Adjustments RB-11 and AMTZ-6?

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[43] Cause No. 45576, Direct Testimony of I&M Witness Jennifer C. Duncan, Attachment JCD-1, p. 11. I&M Witness Ross also sponsors RB-2, which removes non-cash assets and related accumulated depreciation for AROs.

[44] Indianapolis Power and Light Company ("IPL") has recently changed its name to AES Indiana.

[45] Cause No. 45029, Direct testimony of IPL Witness Paula M. Guletsky, pp. 5-6, 10-11, and PMG Attachment 1.

[46] Cause No. 45029, Direct testimony of John J. Spanos, pp. 11-12. With the exception of Eagle Valley CCGT depreciation expense, IPL and interested parties settled to accept IPL's originally proposed depreciation rates. (Cause No. 45029, Settlement Agreement, p. 3).

A: Yes, the OUCC has two concerns in relation to NIPSCO's Adjustments RB-11 and AMTZ-6. The first is that the Commission has yet to issue an order granting NIPSCO's request in Cause No. 45700. While the order is likely to be issued prior to the end of the test year, possible appeals of the order will likely not be resolved by the end of 2023. OUCC Witness Lantrip addresses the OUCC's recommendation regarding the FMCA adjustments in his testimony.

The second issue is that NIPSCO is not including the entire Michigan City Ash Pond Compliance Project costs in this case. NIPSCO plans to continue tracking 80% of these costs through its FMCA, even though the Ash Pond Compliance Project will be complete by the end of the test year. Typically, once projects tracked through the FMCA are complete, they are included in base rates in the next rate case following completion and therefore cease to be tracked. I am not aware of any utility that has been permitted to continue tracking the costs of a federally mandated project beyond the subsequent rate case after its completion. I&M and DEI are permitted to continue tracking O&M costs related to federally mandated projects, but the completed projects have been included in rate base and are no longer tracked.[47]

Q: Does I.C. ch. 8-1-8.4 offer guidance on when the federally mandated project costs are no longer tracked?

A: Yes. I.C. § 8-1-8.4-7(c) states:

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[47] Cause No. 45235, Final Order, pp. 99-100; and Cause No. 45253, Final Order, p. 140.
Note: I&M and DEI have embedded O&M associated with federally mandated costs in base rates, but track increases or decreases in annual O&M through Environmental Cost Riders (ECRs).

> If the commission approves under subsection (b) a proposed compliance project and the projected federally mandated costs associated with the proposed compliance project, the following apply:
>
> (1) Eighty percent (80%) of the approved federally mandated costs shall be recovered by the energy utility through a periodic retail rate adjustment mechanism that allows the timely recovery of the approved federally mandated costs. The commission shall adjust the energy utility's authorized net operating income to reflect any approved earnings for the purposes of IC 8-1-2-42(d)(3) and IC 8-1-2-42(g)(3).
>
> (2) Twenty percent (20%) of the approved federally mandated costs, including depreciation, allowance for funds used during construction, and post in service carrying costs, based on the overall cost of capital most recently approved by the commission, shall be deferred by the energy utility as part of the next general rate case filed by the energy utility with the commission.
>
> (3) Actual costs that exceed the projected federally mandated costs of the approved compliance project by more than twenty-five percent (25%) shall require specific justification by the energy utility and specific approval by the commission before being authorized in the next general rate case filed by the energy utility with the commission.

Although I.C. § 8-1-8.4(c)(1) does not indicate when the 80% portion of federally mandated costs would stop being recovered through a periodic retail rate adjustment mechanism, (c)(3) implies recovery through a general rate case. It does not make sense for only a portion of the completed federally mandated project's costs to be included in base rates while the remaining portion continues to be tracked. Therefore, it is reasonable to conclude that the relief afforded under the FMR statute is meant to serve as a bridge for the utility to recover new federal compliance costs incurred between rate cases. Once the utility files a rate case after completing a federally mandated project, there is no need to continue tracking the project's costs.

Q: What does the OUCC recommend regarding NIPSCO's CCR unit closures?

A: The OUCC recommends NIPSCO include all estimated costs to close CCR ponds and landfills in decommissioning costs and make the appropriate adjustments to depreciation expense, accumulated depreciation, and rate base to incorporate these costs. The OUCC also recommends NIPSCO withdraw its requests in Cause Nos. 45700 and 45797, as these costs would be appropriately recovered through base rates. OUCC witness David Garrett has included $25,946,000 associated with the Michigan City Ash Pond Compliance Project and $46,458,000 associated with the Schahfer Pond Compliance Project in demolition costs.[48]

As OUCC witness Wes Blakley testifies, it is not clear that NIPSCO has removed costs associated with these projects from its forecasted test year, but NIPSCO has debited Account 108 (Accumulated Depreciation) with incurred CCR removal costs of $29,249,829 as of November 2022.[49] If NIPSCO has not included debits to accumulated depreciation associated with the Michigan City and Schahfer CCR pond closures in its forecasted test year, the OUCC recommends NIPSCO charge accumulated depreciation for any expenditures on both projects made as of the end of the test year. As Mr. Blakley discusses, this will have the effect of

[48] Michigan City Ash Pond Compliance Project costs are based on the $40,044,000 cost estimate NIPSCO presented in Cause No. 45700, Petitioner's Attachment 3-A, subtracting $10,797,000 for Michigan City Non-CCR Rule Pond Closure costs included in demolition costs as shown in NIPSCO Witness Jeffrey T. Kopp's Attachment 14-B, p. 36. Schahfer Pond Compliance Project costs are based on the $53,025,000 cost estimate NIPSCO presented in Cause No. 45797, Petitioner's Attachment 3-A. OUCC witness David Garrett also removes contingency and escalation costs associated with both projects.

[49] As Mr. Blakley states in his testimony, this breaks down to $25,468,752 for Michigan City and $3,781,072 for Schahfer.

increasing rate base. Based on the projected costs of the Michigan City Ash Pond Compliance Project and the costs NIPSCO has incurred on the Schahfer Ash Pond Project as of November 2022, the OUCC recommends decreasing test year accumulated depreciation by $40,524,072.[50] OUCC Witness Mark Garrett makes this adjustment in his schedules. As Mr. Lantrip addresses in his testimony, the portion of NIPSCO's test year adjustments for FMCA deferrals associated with an assumed Commission approval in Cause No. 45700 (AMTZ-6 and RB-11) should be denied.

If the Commission allows NIPSCO to exclude CCR costs from decommissioning costs and allows the cost recovery NIPSCO requested in Cause No. 45700, then the OUCC recommends NIPSCO be required to stop tracking the Michigan City Ash Pond Compliance Project through its FMCA and to include its full cost in determining NIPSCO's revenue requirement in this Cause.

IV. JOINT VENTURE RESERVE ACCOUNT

Q: Please explain NIPSCO's request regarding its renewable generation joint ventures.

A: When NIPSCO sought approval to enter into a joint venture for the Rosewater Wind, Indiana Crossroads Wind, Dunn's Bridge I Solar, and Indiana Crossroads Solar, NIPSCO made a commitment to not record and accumulate project revenues

[50]This adjustment assumes, $36,743,000 for Michigan City's costs, which excludes contingency, and $3,781,000 for Schahfer's costs. Mr. Blissmer discusses adjusting decommissioning costs to remove non-CCR pond closures in his direct testimony but does not discuss any charges to accumulated depreciation for these ponds (See Blissmer Direct, pp. 8-11.) Therefore, the OUCC includes the non-CCR pond closure costs in its adjustment to accumulated depreciation. Since these costs are currently included in NIPSCO's decommissioning costs, Mr. David Garrett's adjustment to decommissioning costs would reflect the difference between the estimated Michigan City Pond Compliance Project and the non-CCR costs included in NIPSCO's decommissioning study.

or joint venture expenses on NIPSCO's books and records. All revenues and expenses are to be maintained by the joint venture, tracked and reviewed by NIPSCO and the OUCC, and subject to an independent audit. When the proceeds from the power purchase agreement between NIPSCO and the applicable joint venture exceed the joint venture's operating costs plus a certain amount of contingency ("reserve"), NIPSCO credits the excess funds to its customers through the FAC.

NIPSCO requests to allow the reserve amounts held at each individual joint venture to be consolidated into one reserve account at the NIPSCO level. This modification will allow NIPSCO to hold a lower total contingency amount, which will permit it to pass back excess cash to customers in a timelier manner. As each project comes online, a project-specific "reserve" would not need to be built up for each project. Currently, the overall reserve amount for each project is between $2 million and $7 million, depending on the project size, or $15 million for the four renewable projects rolling into base rates in this Cause. If this change is approved, NIPSCO states the reserve amount could be reduced by about $7.5 million.[51]

Q: Does the OUCC take issue with NIPSCO's request to consolidate individual joint venture reserve accounts into one company-level reserve account?

A: No. This aspect of NIPSCO's proposal appears to provide benefits to ratepayers, as NIPSCO will be able to pass back excess cash distributions from joint ventures more quickly to customers through the FAC. The OUCC recommends approval of NIPSCO's request to consolidate joint venture reserve accounts.

[51] Direct Testimony of NIPSCO Witness Erin E. Whitehead, pp. 29-31.

V. CONCLUSION

Q: Please summarize your recommendations:

A: My recommendations are:

1. NIPSCO's request for the VCT should be denied.
2. $91,715,971 of forecasted O&M costs for coal-fired generation should be embedded in base rates.
3. NIPSCO's estimated $9.96 million in Seasonal Allowance Costs should be denied, and this denial should be reflected in the OUCC's recommended amount embedded in rates for VCT related costs.
4. NIPSCO should include all estimated costs to close CCR ponds and landfills in decommissioning costs and adjust depreciation expense to incorporate these costs. Any closure costs the Company has incurred to date should be recorded to accumulated depreciation.
5. NIPSCO's request to consolidate the reserve amounts held at each individual joint venture into one reserve account at the NIPSCO level should be approved.

Q: Does this conclude your testimony?

A: Yes.

APPENDIX A

Q: Summarize your professional background and experience.

A: I graduated from the University of Evansville in 2004 with a Bachelor of Science degree in Environmental Administration. I graduated from Indiana University, Bloomington in May 2007 with a Master of Public Affairs degree and a Master of Science degree in Environmental Science. I have also completed internships with the Environmental Affairs Department at Vectren in the spring of 2004, with the U.S. Environmental Protection Agency in the summer of 2005, and with the U.S. Department of the Interior in the summer of 2006. During my final year at Indiana University, I served as a research and teaching assistant for a Capstone course offered at the School of Public and Environmental Affairs. I also have obtained my OSHA Hazardous Operations and Emergency Response ("HAZWOPER") Certification. I have been employed by the OUCC since May 2007, and I was promoted to my current position of Chief Technical Advisor in June 2022. As part of my continuing education at the OUCC, I attended both weeks of the National Association of Regulatory Utility Commissioners' ("NARUC") seminar in East Lansing, Michigan, completed 8-hour OSHA HAZWOPER refresher courses, and attended the Indiana Chamber of Commerce's Environmental Permitting Conference and annual Environmental Conferences.

Q: Describe some of your duties at the OUCC.

A: I review and analyze utilities' requests and file recommendations on behalf of consumers in utility proceedings. Depending on the case at hand, my duties may also include analyzing state and federal regulations, evaluating rate design and tariffs, examining books and records, inspecting facilities, and preparing various studies. Since my expertise lies in environmental science and policy, I assist in many cases where environmental compliance is an issue.

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OUCC Request 17-009:
Please provide the monthly inventory balance calculations for NIPSCO's Annual NOx, Seasonal NOx, and SO_2 allowance inventories for the past four (4) years. As part of these calculations, please include: beginning balance, allowance additions, allowance sales, allowance consumption, the weighted average cost of inventory, and any other adjustments influencing inventory costs.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation, or compilation which has not already been performed and which NIPSCO objects to performing. NIPSCO is providing responsive information in the manner in which it is kept in the ordinary course of business.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO's annual allowance inventory calculations are included in OUCC Request 17-009 Attachment A. NIPSCO does not track inventory balances on a monthly basis, nor does it track the weighted average cost of the inventory. Beginning balance, allowance additions, allowance sales, allowances consumption, and other adjustments have been included.

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Annual CSAPR NOx Allowance Inventory

	2018	2019	2020	2021
Beginning Inventory Balance	2,363	5,377	8,739	11,973
Initial Allocations	13,178	13,178	13,178	13,026
Total Beginning Balance	15,541	18,555	21,917	24,999
Allowance Reallocation from State of IN	311	309	975	377
Purchase/(Sale) of Allowances	-	-	-	-
Total Allowances in Inventory	15,852	18,864	22,892	25,376
Less: Emissions	(7,376)	(5,635)	(3,620)	(4,690)
End of year balance before Surrender	8,476	13,229	19,272	20,686
Less: Surrender to EPA*	(3,099)	(4,490)	(7,299)	(3,547)
End of year balance after Surrender	**5,377**	**8,739**	**11,973**	**17,139**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Seasonal CSAPR NOx Allowance Inventory

	2018	2019	2020	2021**
Beginning Inventory Balance	430	534	1,403	-
Initial Allocations	3,321	3,321	3,321	2,421
Total Beginning Balance	3,751	3,855	4,724	2,421
Allowance Reallocation from State of IN	62	62	56	35
Purchase/(Sale) of Allowances	-	-	-	96
Total Allowances in Inventory	3,813	3,917	4,780	2,552
Less: Emissions	(3,279)	(2,387)	(1,561)	(2,488)
End of year balance before Surrender	534	1,530	3,219	64
Less: Surrender to EPA*	-	(127)	(1,101)	-
End of year balance after Surrender	**534**	**1,403**	**2,118**	**64**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Annual CSAPR SO2 Allowance Inventory

	2018	2019	2020	2021
Beginning Inventory Balance	81,340	103,038	125,618	149,348
Initial Allocations	23,522	23,522	23,522	28,998
Total Beginning Balance	104,862	126,560	149,140	178,346
Allowance Reallocation from State of IN	700	718	1,671	893
Purchase/(Sale) of Allowances	-	-	-	-
Total Allowances in Inventory	105,562	127,278	150,811	179,239
Less: Emissions	(2,524)	(1,660)	(1,463)	(1,684)
End of Year Balance	**103,038**	**125,618**	**149,348**	**177,555**

NORTHERN INDIANA PUBLIC SERVICE COMPANY
Annual Acid Rain SO2 Allowance Inventory

	2018	2019	2020	2021
Beginning Inventory Balance	263,396	289,118	302,003	315,086
Initial Allocations	50,706	50,706	50,706	50,706
Total Beginning Balance	314,102	339,824	352,709	365,792
Allowance Reallocation from State of IN	-	-	-	-
Purchase/(Sale) of Allowances	-	-	-	-
Total Allowances in Inventory	314,102	339,824	352,709	365,792
Less: Emissions	(2,523)	(1,660)	(1,463)	(1,684)
End of year balance before Surrender	311,579	338,164	351,246	364,108
Less: Surrender to EPA*	(22,461)	(36,161)	(36,160)	(36,162)
End of year balance after Surrender	**289,118**	**302,003**	**315,086**	**327,946**

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OUCC Request 17-005:
Does NIPSCO plan to track changes to materials and supplies inventory in the VCT? If so, please explain how this will be reflected. If not, please explain why not.
Objections:
Response:
No. The VCT is meant to capture O&M expenses directly tied to generating units.

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OUCC Request 17-001:
Please refer to p. 34, lines 17-18, through p. 35, lines 1-3, of Kevin Blissmer's testimony. a. Please provide supporting documentation, calculations, and assumptions in electronic format for the cost estimates provided for each of the six categories of costs to be tracked via the VCT. b. Please provide a breakdown of these costs by unit. c. Please provide the annual historical expenditures for each of these six categories over the past four (4) calendar years. d. Please provide the current unit outage and maintenance schedule for Schahfer Units 17 and 18 and Michigan City Unit 12. e. For each scheduled outage listed in (d) above, please list the components or major projects to be completed and their associated estimated cost. f. For each component or project listed in (e) above, please indicate the last time NIPSCO performed this work on this unit and how often this work or replacement generally occurs. g. Please provide a detailed description and breakdown of the types of activities or costs included in Planned Outage and Forced Outage cost categories. h. Please list all chemicals that will be tracked in the Variable Chemicals category. i. Please provide a detailed description and breakdown of activities or work included in the Non-trackable Fuel Handling category. j. Do any of these six cost categories contain NiSource Corporate Service Fees? If so, please provide the amount of Corporate Service fees that will be collected in each cost category and by generating unit. k. Please provide the number of SO_2, Annual NOx, and Seasonal NOx allowances allocated annually to NIPSCO's units for compliance with the Acid Rain Program and the Cross State Air Pollution Rule (CSAPR). If NIPSCO continues to receive allowances for previously retired units, please also provide those allowance allocations. l. Please provide the unit monthly SO_2 and NO_x emissions for Schahfer Units 17 and 18 and Michigan City Unit 12 for the past five years. m. Are there any labor costs allocated to and included in the amounts for any of the six categories of O&M costs to be tracked via the VCT?
Objections:

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Response:

a. Please see Petitioner's Confidential Exhibit No. 22-S2 as detailed in the table below for support for each of the six categories of costs to be tracked by the Variable Cost Tracker ("VCT"):

Workpaper	Description	Page	Line No(s).	OM-2K Page 2 Amount
OM 2A	Generation Maintenance Activity	4	9 less 5-6	$34,094,580
OM 2B	Planned Outages	13	5 less 3-4	$11,893,401
OM 2C	Forced Outages	4	8 less 5	$4,648,497
OM 2D	Variable Chemicals	4	36	$21,365,434
OM 2E	Non-Trackable Fuel Handling	4	N/A	$19,714,059
OM 2H	NOx Emission Allowances	4	3	$9,960,000

b. NIPSCO accounts for some, although not all, VCT cost categories by unit. The costs categories that are not accounted for by unit are accounted for by station. For a detail of costs associated with the VCT cost categories, please see Petitioner's Confidential Exhibit No. 22-S2 as detailed in the table below:

Workpaper	Description	Page(s)	Costs by Unit/Station
OM 2A	Generation Maintenance Activity	2, 3A, & 4	Station
OM 2B	Planned Outages	2 & 5-13	Unit
OM 2C	Forced Outages	4	Station

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OM 2D	Variable Chemicals	4	Unit
OM 2E	Non-Trackable Fuel Handling	4	Unit
OM 2H*	NOx Emission Allowances	4	Station

* Additionally, please see OUCC Request 17-001 Confidential Attachment A for the unit costs associated with NOx Emission allowances. In preparing this response NIPSCO discovered 52 NOx Emission Allowances were included for Schahfer Unit 16A and 16B and Sugar Creek in the Variable Cost Tracker in error amounting to $1,560,000. NIPSCO will increase its base rate request and decrease its Variable Cost Tracker by this amount in its rebuttal filing.

c. Please see OUCC Request 17-001 Attachment B for the four most recent calendar years of expense activity associated with base maintenance, planned outages, forced outages, variable chemicals, and non-trackable fuel. There is no expense activity in the four most recent calendar years associated with NOx emissions allowances. NIPSCO notes that OUCC Request 17-001 Attachment B includes costs associated with all generation assets.

d. For the current unit outage and maintenance schedule for Schahfer Units 17 and 18 and Michigan City Unit 12, please see Petitioner's Confidential Exhibit No. 22-S2, Workpaper OM 2B, pages 5-12.

e. Please see NIPSCO's response to subpart d for the components or major projects to be completed and their associated estimated costs.

f. Please see table below:

	Standard Outage Package	Continuous Improvement	High Energy Piping
Schahfer Units 17/18	OUCC 15-4 OM2B page [.5]	OUCC 15-7 OM2B page [.6]	OUCC 15-10 OM2B page [.7]

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	OUCC 15-14 OM2B page [.10]	OUCC 15-16 OM2B page [.11]	OUCC 15-19 OM2B page [.12]
Michigan City U12	OUCC 15-3 OM2B page [.5]	OUCC 15-6 OM2B page [.6]	OUCC 15-9 OM2B page [.7]
	OUCC 15-13 OM2B page [.10]	OUCC 15-17 OM2B page [.11]	OUCC 15-18 OM2B, page [.12]

g. Detailed work scope is developed based on service requests submitted while unit is operating in addition to physical inspections performed at the start of each outage. The areas included are specified in Petitioner's Confidential Exhibit No. 22-S2, Workpaper OM 2B, pages 5-12. Costs associated with scope are managed within the budgets listed within the noted workpapers.

h. For a list of chemicals NIPSCO is currently proposing to be tracked through the VCT, please see Petitioner's Confidential Exhibit 22-S2, Workpaper OM 2D. To the extent NIPSCO would require the use of chemicals not currently within the scope of the chemicals detailed in the workpaper referenced above, NIPSCO would subsequently propose to recover the additional costs associated with those additional chemicals necessary to operate the coal fired generation units through the VCT.

i. Non-Trackable Fuel Handling includes costs associated with the unloading of fuel from the shipping medium and the handling thereof prior to its use. The FERC Uniform System of Accounts describes the types of costs included in Fuel Handling: Labor associated with (1) procuring and handling of fuel, (2) routine fuel analyses, (3) unloading from shipping facility and putting in storage, (4) moving of fuel in storage and transferring from one station to another, (5) handling from storage or shipping facility to first bunker, hopper, bucket, tank or holder of boiler house structure, (6) operation of mechanical equipment, such as locomotives, trucks, cars, boats, barges, cranes, etc. and Supplies and Expenses associated with: (7) tools, lubricants and other supplies, (8) operating supplies for mechanical equipment, (9) transportation and other expenses in moving fuel, and (10) stores expenses applicable to fuel. The FERC Uniform System of Accounts requires recording of these costs to account 152 Fuel stock expense when incurred and subsequently recording to Fuel Handling expense as the fuel is used in

Cause No. 45772
Northern Indiana Public Service Company LLC's
Objections and Responses to
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production. These costs need to be sufficiently significant in amount to warrant being treated as part of the cost of fuel inventory; otherwise, they are expenses as incurred. Labor included in Non-Trackable Fuel Handling is not recorded to a labor account in accordance with the guidance noted above.

j. No.

k. NIPSCO has been allocated the following allowances from the EPA (values in tons)

	CSAPR Annual NOx Program	CSAPR Seasonal NOx Program	CSAPR SO2 Program	Acid Rain Program
2022	13,026	1,579	28,998	
2023	13,026		28,998	
2024	12,178		21,725	
2022-2052				50,706 annually

l. Please see OUCC Request 17-001 Confidential Attachment C.

m. There is no labor expense in the proposed VCT. The VCT includes Non-Trackable Fuel Handling. Please see response to subpart i for a description of Non-Trackable Fuel Handling.

[redacted]

[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

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[redacted]		[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2021
Generation Base Maintenance Expense - Non-labor

Line No.	Segment	Description	Cost Element	2021 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2021
1	Electric	Base Maintenance	Dues & Donations	40,450	12,850	(8,800)	12,803	2,400	-	40,000	43,568	1,200	-	3,650	1,200	149,320
2			Employee Expenses	21,495	59,264	47,467	27,902	27,339	28,710	30,123	54,833	35,690	35,937	61,373	60,058	490,191
3			Materials and Supplies	1,987,458	1,779,825	2,022,338	1,367,420	1,129,374	1,969,447	1,604,874	530,366	1,832,227	1,193,391	901,764	1,270,675	17,589,158
4			Misc and Other Expenses	111,465	56,068	56,584	22,675	74,712	45,043	77,867	84,937	79,393	47,244	108,125	155,332	919,445
5			Outside Services	1,555,955	2,706,317	3,409,057	1,126,404	1,924,566	1,894,932	1,729,353	3,474,799	1,215,310	1,922,622	2,309,638	1,959,739	25,228,694
6			Rents & Leases	325,592	33,334	205,067	(15,633)	65,967	45,867	20,353	(2,503)	33,117	(51,075)	249,692	(60,604)	849,174
7			Vehicle & Tools Costs	8	672	1,737	(0)	(0)	0	-	40	350	-	-	12	2,819
8			Subtotal	$ 4,042,424	$ 4,648,329	$ 5,733,451	$ 2,541,570	$ 3,224,357	$ 3,983,999	$ 3,502,571	$ 4,186,039	$ 3,197,286	$ 3,148,120	$ 3,634,242	$ 3,386,412	$ 45,228,801
9			Less : Unit 14/15 Spend													(5,814,372)
10			Total Base Maintenance for 2021													39,414,429

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2020
Generation Base Maintenance Expense - Non-labor

Line No.	Segment		Cost Element	2020 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2020
1	Electric	Base Maintenance	Dues & Donations	-	-	-	-	-	-	-	-	-	-	-	-	-
2			Employee Expenses	16,984	20,304	12,921	5,136	2,357	5,113	7,419	5,387	4,163	6,796	4,046	7,597	98,224
3			Materials and Supplies	847,687	563,227	666,268	806,331	1,092,867	910,651	396,392	714,823	879,911	667,487	460,510	576,551	8,582,704
4			Misc and Other Expenses	2,972,741	1,256,941	1,710,567	2,357,195	1,375,619	1,410,423	2,213,348	2,111,404	1,046,982	3,022,244	1,065,109	2,454,697	22,997,269
5			Outside Services	350,649	1,873,932	1,764,075	478,526	281,336	724,040	397,230	734,116	1,904,303	1,072,744	2,488,004	2,073,191	14,142,147
6			Rents & Leases	278,330	142,984	67,159	75,002	8,779	146,985	271,228	209,902	341,043	(231,995)	556,664	328,908	2,194,988
7			Vehicle & Tools Costs	25	102	104	0	-	-	-	69	-	-	-	-	301
8			Subtotal	$ 4,466,416	$ 3,857,490	$ 4,221,094	$ 3,722,189	$ 2,760,958	$ 3,197,212	$ 3,285,618	$ 3,775,702	$ 4,176,402	$ 4,537,275	$ 4,574,332	$ 5,440,944	$ 48,015,633
9																
10			Total Base Maintenance for 2020													48,015,633

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2019
Generation Base Maintenance Expense - Non-labor

Line No.	Segment		Cost Element	2019 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2019
1	Electric	Base Maintenance	Dues & Donations	3,295	171,086	611	74,174	108,881	150	110,394	-	15,659	99,044	300	-	583,595
2			Employee Expenses	37,769	73,446	87,390	68,174	58,926	53,549	34,652	61,985	69,037	60,232	52,100	43,052	700,313
3			Materials and Supplies	2,084,387	1,609,973	798,182	274,932	842,757	1,188,683	1,163,962	1,561,475	1,004,017	508,981	860,557	1,314,517	13,212,422
4			Misc and Other Expenses	61,643	73,973	62,055	100,982	49,640	65,987	46,708	149,631	82,711	401,558	233,460	473,938	1,802,287
5			Outside Services	1,192,974	1,220,939	2,150,976	2,404,982	2,698,924	2,478,366	2,447,438	2,413,207	3,429,692	3,607,314	3,634,850	2,960,106	30,639,768
6			Rents & Leases	27,681	155,291	259,142	143,695	236,331	270,049	15,732	364,496	113,663	14,207	132,880	(4,634)	1,728,533
7			Vehicle & Tools Costs	16	(0)	-	65	9	8	8	5	5	25	10	-	151
8			Subtotal	$ 3,407,765	$ 3,304,708	$ 3,358,356	$ 3,067,004	$ 3,995,468	$ 4,056,794	$ 3,818,894	$ 4,550,799	$ 4,714,784	$ 4,691,361	$ 4,914,157	$ 4,786,979	$ 48,667,068
9																
10			Total Base Maintenance for 2019													48,667,068

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2018
Generation Base Maintenance Expense - Non-labor

Line No.	Segment		Cost Element	January 2018	February 2018	March 2018	April 2018	May 2018	June 2018	July 2018	August 2018	September 2018	October 2018	November 2018	December 2018	Twelve Months Ended December 31, 2018
1	Electric	Base Maintenance	Dues & Donations	183,255	190	372	180,339	318	2,503	180,294	560	(1,980)	180,681	139	4,770	731,441
2			Employee Expenses	32,250	53,012	85,112	73,704	50,843	57,964	54,230	89,263	69,046	58,422	64,730	66,856	755,431
3			Materials and Supplies	806,913	1,152,033	946,865	1,592,802	1,464,253	1,006,487	1,285,073	1,297,351	1,613,362	1,143,778	1,034,549	1,897,949	15,241,414
4			Misc and Other Expenses	196,397	208,558	69,304	67,377	100,730	106,207	55,048	858,650	97,924	402,308	248,850	85,907	2,497,261
5			Outside Services	4,370,013	3,475,096	2,620,960	3,665,315	2,992,366	3,007,370	3,027,189	2,406,596	2,329,144	2,469,438	2,281,198	3,250,980	35,895,664
6			Rents & Leases	411,271	221,849	146,504	213,085	101,636	52,952	321,154	354,419	144,985	31,894	113,523	139,686	2,252,957
7			Vehicle & Tools Costs	9	10	5	0	0	(0)	(0)	(0)	275	8	560	(0)	867
8			Subtotal	$ 6,000,107	$ 5,110,747	$ 3,869,123	$ 5,792,621	$ 4,710,146	$ 4,233,483	$ 4,922,987	$ 5,006,839	$ 4,252,756	$ 4,286,528	$ 3,743,550	$ 5,446,148	$ 57,375,035
9																
10			Total Base Maintenance for 2018													57,375,035

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2021
O&M Planned outage - non-labor

Line No.	Segment	Cost Element	2021 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2021
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O = C through N
1	E	Michigan City Gen Station	32,050	40,279	363,614	3,390,672	1,363,747	374,057	(53,442)	10,252	10,665	(7,486)	13,215	(9,549)	5,528,074
2	E	R M Schahfer Gen Station	(115,660)	(107,769)	(102,022)	(30,198)	(102)	(369,350)	189,639	(1,012,315)	116,040	11,101	3,032,779	333,843	1,945,988
3	E	Sugar Creek Gen Station	99,410	7,542	82,750	(97,754)	-	6,000	4,480	20,656	258,430	359,743	19,792	63,410	824,461
4	E	Other	-	-	-	-	-	-	-	-	-	-	-	-	-
5	E	Total Planned Outages	$ 15,801	$ (59,948)	$ 344,342	$ 3,262,720	$ 1,363,645	$ 10,707	$ 140,678	$ (981,408)	$ 385,135	$ 363,358	$ 3,065,786	$ 387,705	$ 8,298,522

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2020
O&M Planned outage - non-labor

Line No.	Segment	Cost Element	2020 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2020
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O = C through N
1	E	Michigan City Gen Station	(207,470)	-	41,600	3,664	(459)	-	-	-	-	-	-	96,353	(66,312)
2	E	R M Schahfer Gen Station	152,394	(109,559)	638,938	337,108	11,612	49,481	(17,330)	106,590	1,911,274	2,681,914	5,220,250	891,377	11,874,050
3	E	Sugar Creek Gen Station	140,452	-	48,123	19,192	4,223	20,422	(16,255)	57,451	142,875	893,341	1,163,259	(22,604)	2,450,478
4	E	Other	-	2,728	-	-	-	-	-	-	-	-	-	-	2,728
5	E	Total Planned Outages	$ 85,375	$ (106,831)	$ 728,660	$ 359,963	$ 15,376	$ 69,903	$ (33,585)	$ 164,041	$ 2,054,150	$ 3,575,255	$ 6,383,509	$ 965,126	$ 14,260,943

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2019
O&M Planned outage - non-labor

Line No.	Segment	Cost Element	2019 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2019
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O = C through N
1	E	Michigan City Gen Station	650,669	3,637,161	4,799,719	5,686,270	1,620,396	75,623	78,032	(94,608)	2,347	5,975	37,151	155,441	16,654,176
2	E	R M Schahfer Gen Station	(14,660)	66,506	(159,518)	43,522	121,566	(37,794)	68,996	201,349	626,421	5,512,260	3,416,389	867,269	10,712,307
3	E	Sugar Creek Gen Station	(7,925)	65,794	(10,727)	54,345	622,253	(68,041)	99,364	10,116	53,910	40,000	(57,068)	120,187	922,208
4	E	Other	28	-	1,004	10	-	-	1,013	37	-	1,250	2,642	8,501	14,485
5	E	Total Planned Outages	$ 628,113	$ 3,769,462	$ 4,630,479	$ 5,784,148	$ 2,364,215	$ (30,212)	$ 247,404	$ 116,894	$ 682,678	$ 5,559,486	$ 3,399,114	$ 1,151,398	$ 28,303,177

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2018
O&M Planned outage - non-labor

Line No.	Segment	Cost Element	2018 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2018
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O = C through N
1	E	Michigan City Gen Station	(13,792)	(12,596)	1,635	98,465	(97,381)	26,565	27,756	23,232	292,712	152,196	330,829	90,502	920,122
2	E	R M Schahfer Gen Station	(42,801)	169,139	3,887,152	4,362,064	920,246	91,563	20,972	150,881	1,707,205	3,246,548	927,570	51,220	15,491,760
3	E	Sugar Creek Gen Station	14,300	-	-	-	38,002	50,230	84,149	237,081	712,085	1,009,572	522,532	63,294	2,731,248
4	E	Bailly Gen Station	4,143	(15)	4,895	173	2,368	-	27	-	-	-	-	-	11,591
5	E	Other	26	-	58	(40)	356	377	-	75	-	-	-	450	1,302
6	E	Total Planned Outages	$ (38,124)	$ 156,528	$ 3,893,740	$ 4,460,663	$ 863,591	$ 168,735	$ 132,904	$ 411,269	$ 2,712,002	$ 4,408,316	$ 1,780,931	$ 205,467	$ 19,156,023

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2021
O&M: Forced outage - Non-Labor

Line No.	Segmen	Cost Element	2021 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2021
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O = C through N
1	E	Gen Ops & Maint Admin	$ -	$ -	$ -	$ -	$ 13,358	$ 3,277	$ (8,157)	$ 28,602	$ -	$ 8,079	$ (8,079)	$ (7,625)	$ 29,455
2	E	Michigan City Gen Station	295,939	(133,747)	(43,091)	-	-	0	48,161	101,996	253,987	50,560	176,583	716,886	1,467,274
3	E	R M Schahfer Gen Station	1,058,980	1,484,558	(1,087,008)	519,842	1,019,813	85,083	275,061	(194,063)	130,818	442,271	(443,072)	141,828	3,434,109
4	E	Sugar Creek Gen Station	54,100	4,397	54,799	174,868	(34,184)	41,077	6,483	(57,605)	-	(1,993)	-	-	241,943
5	E	Total Planned Outages	$ 1,409,019	$ 1,355,209	$ (1,075,301)	$ 694,710	$ 998,986	$ 129,437	$ 321,549	$ (121,070)	$ 384,805	$ 498,916	$ (274,568)	$ 851,088	$ 5,172,781
6		Less : Unit 14/15 Spend													(264,359)
7		Normalized Planned Outages for 2021													4,908,422

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2020
O&M: Forced outage - Non-Labor

Line No.	Segmen	Cost Element	2020 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2020
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O = C through N
1	E	Gen Ops & Maint Admin					$ -	$ -	$ -	$ 216,765	$ (216,765)	$ 462,605	$ -	$ 3,182	$ 465,787
2	E	Michigan City Gen Station	37,818	(2,804)	857,252	97,975	173,809	22,295	186,239	49,905	-	(5,153)	39,462	937,242	2,394,040
3	E	R M Schahfer Gen Station	353,800	493,662	(185,397)	26,514	(207,634)	(246,401)	2,833,044	4,975,066	1,805,586	723,335	1,094,538	831,574	12,497,686
4	E	Sugar Creek Gen Station	-	-	-	(34,360)	37,999	(23,776)	1,200	19,845	-	28,514	27,395	-	56,816
5	E	Other	-	-	-	-	-	-	48	456	565	1,138	87	-	2,294
5	E	Total Planned Outages	$ 391,617	$ 490,858	$ 671,855	$ 90,129	$ 4,174	$ (247,883)	$ 3,020,531	$ 5,262,036	$ 1,589,386	$ 1,210,440	$ 1,161,482	$ 1,771,998	$ 15,416,623

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2019
O&M: Forced outage - Non-Labor

Line No.	Segmen	Cost Element	2019 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2019
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O = C through N
1	E	Bailly Gen Station	$ 0	$ 19,844	$ (27,849)		$ (106,520)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (114,525)
2	E	Michigan City Gen Station	1,573	(1,492)	(7,937)	(8,846)	-	-	10,114	148,726	583,329	(11,695)	51,661	1,383,016	2,148,450
3	E	R M Schahfer Gen Station	231,720	940,664	442,828	1,047,348	1,066,180	1,226,400	354,513	662,996	(119,837)	(98,963)	110,945	1,681,703	7,546,498
4	E	Sugar Creek Gen Station	-	519	-	-	-	65,086	(2,693)	-	-	-	109,777	(35,309)	137,380
5	E	Total Planned Outages	$ 233,293	$ 959,536	$ 407,042	$ 1,038,502	$ 959,660	$ 1,291,486	$ 361,934	$ 811,722	$ 463,492	$ (110,657)	$ 272,382	$ 3,029,410	$ 9,717,803

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2018
O&M: Forced outage - Non-Labor

Line No.	Segmen	Cost Element	2018 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2018
	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O = C through N
1	E	Gen Ops & Maint Admin	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1	E	Bailly Gen Station	$ 955,447	$ (10,719)	$ 221,573	$ 107,006	$ 220,456	$ 370,765	$ (72,611)	$ 98,482	$ (45,115)	$ (62,060)	$ 26,043	$ (7,420)	$ 1,801,845
2	E	Michigan City Gen Station	(6,803)	344,565	19,602	902,294	104,728	27,146	670,549	746,153	347,134	(83)	(33,556)	(6,500)	3,115,229
3	E	R M Schahfer Gen Station	857,178	907,694	265,569	281,808	384,053	942,898	426,277	274,220	262,896	192,591	125,873	310,766	5,231,824
4	E	Sugar Creek Gen Station	-	-	-	-	-	-	21,737	16,343	(13,663)	(6,500)	-	-	17,917
5	E	Total Planned Outages	$ 1,805,821	$ 1,241,540	$ 506,744	$ 1,291,108	$ 709,237	$ 1,340,809	$ 1,045,952	$ 1,135,198	$ 551,251	$ 123,948	$ 118,360	$ 296,846	$ 10,166,816

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2021

Line No.	Station	Cost Element	2021 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2021
1	Michigan City Gen Station	27225 - AMMONIA EXPENSE	107,606	256,013	46,060	-	59,470	141,593	199,855	214,110	185,135	377,966	164,585	115,248	1,867,641
2		6944 - Pebble Lime	186,237	392,722	49,976	3,017	35,195	211,379	318,598	434,520	419,544	240,551	422,895	50,041	2,764,675
3		2001 - Chemicals (ACI)	89,473	-	-	-	-	14,365	138,981	6,334	(1,021)	84,451	-	92,031	424,615
4	R M Schahfer Gen Station	26940 - Purchase Ammonia	-	-	-	-	-	-	-	-	-	-	-	-	-
5		26957 - Purchase Dibasic Acid	123,736	(1,074)	120,644	87,576	88,846	104,939	108,371	108,931	108,335	161,882	106,414	84,087	1,202,686
6		26966 - Purchase Limestone	796,492	180,149	300,587	714,985	882,998	689,935	211,644	988,586	1,183,493	522,681	545,463	625,767	7,642,778
7		27225 - AMMONIA EXPENSE	-	17,896	-	61,875	(49,676)	94,637	36,080	64,317	(135,481)	-	-	-	89,647
8		2001 - Chemicals (ACI)	62,315	86,951	122,961	62,932	62,624	62,685	-	25,564	-	-		64,707	550,739
9		**Total**	**$ 1,365,858**	**$ 932,658**	**$ 640,227**	**$ 930,385**	**$ 1,079,456**	**$ 1,319,533**	**$ 1,013,530**	**$ 1,842,363**	**$ 1,760,005**	**$ 1,387,531**	**$ 1,239,356**	**$ 1,031,880**	**$ 14,542,781**
10		Less : Unit 14/15 Spend													(897,199)
11		**Normalized Planned Outages for 2021**													**$ 13,645,582**

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2020

Line No.	Station	Cost Element	2020 January	February	March	April	May	June	July	August	September	October	November	December	Actuals Twelve Months Ended December 31, 2020
1	Michigan City Gen Station	27225 - AMMONIA EXPENSE	226,528	198,066	40,550	(4,203)	-	31,207	90,560	223,332	179,883	175,686	104,107	-	1,265,717
2		6944 - Pebble Lime	376,534	371,670	154,597	(3,943)	-	20,547	95,056	254,019	341,770	303,320	312,340	(27,783)	2,198,128
3		2001 - Chemicals (ACI)	11,096	30,219	37,838	122,296	-	-	-	-	-	89,502	-	-	290,950
4	R M Schahfer Gen Station	26940 - Purchase Ammonia													-
5		26957 - Purchase Dibasic Acid	19,092	84,366	34,436	68,000	(32,779)	85,541	101,631	119,603	120,514	86,147	86,904	85,096	858,551
6		26966 - Purchase Limestone	430,401	714,106	945,046	374,961	295,498	505,349	811,164	666,771	750,650	462,063	511,143	520,550	6,987,702
7		27225 - AMMONIA EXPENSE	70,399	21,412	18,162	78,506	(8,097)	6,929	83,912	(1)	-	(2,753)	-	16,967	285,437
8		2001 - Chemicals (ACI)	123,691	61,436	61,772	181,973	62,000	-	124,000	(1,305)	(62,000)	-	-	-	551,568
9		**Total**	**$ 1,257,742**	**$ 1,481,275**	**$ 1,292,400**	**$ 817,591**	**$ 316,621**	**$ 649,573**	**$ 1,306,323**	**$ 1,262,420**	**$ 1,330,818**	**$ 1,113,966**	**$ 1,014,494**	**$ 594,830**	**$ 12,438,054**

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Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2019

Line No.	Station	Cost Element	2019 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2019
1	Michigan City Gen Station	27225 - AMMONIA EXPENSE	123,654	0	(0)	-	66,388	120,241	237,474	168,663	(2)	18,433	138,727	43,579	917,157
2		6944 - Pebble Lime	-	-	-	-	-	-	-		-	-	-	-	-
3		2001 - Chemicals (ACI)	-	-	-	-	-	-	-	-	-	-	-	-	-
4	R M Schahfer Gen Station	26940 - Purchase Ammonia	146,778	22,416	40,578	70,750	83,237	(3,014)	189,417	42,209	-	-	-	-	592,371
5		26957 - Purchase Dibasic Acid	175,630	131,008	119,666	65,421	228,656	31,653	66,906	132,451	99,524	115,121	97,888	147,091	1,411,015
6		26966 - Purchase Limestone	1,026,281	778,703	1,105,489	734,366	1,114,476	682,999	864,557	752,161	587,940	783,854	793,651	615,284	9,839,760
7		27225 - AMMONIA EXPENSE	(49,463)	141,209	167,222	97,978	56,594	208,908	66,581	148,851	247,149	(8,868)	(35,179)	57,783	1,098,766
8		2001 - Chemicals (ACI)	190,046	57,250	120,455	185,102	61,509	184,810	312	61,694	124,000	61,384	61,481	(126,926)	981,116
9		**Total**	**$ 1,612,925**	**$ 1,130,586**	**$ 1,553,409**	**$ 1,153,618**	**$ 1,610,859**	**$ 1,225,597**	**$ 1,425,246**	**$ 1,306,029**	**$ 1,058,611**	**$ 969,925**	**$ 1,056,568**	**$ 736,811**	**$ 14,840,185**
														Bailly Gen Station	(14 325)
															14,825,860

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2018

Line			2018												Twelve Months Ended
No.	Station	Cost Element	January	February	March	April	May	June	July	August	September	October	November	December	December 31, 2018
1	Bailly Gen Station	27225 - AMMONIA EXPENSE	56,759	48,825	35	-	-	-	-	-	-	-	-	-	105,619
2		26966 - Purchase Limestone	208,195	207,847	129,735	66,737	(472,866)	-	-	-	-	-	-	-	139,649
3	Michigan City Gen Station	27225 - AMMONIA EXPENSE	211,693	123,434	141,260	51,854	157,950	188,560	74,298	22,790	154,145	175,451	74,098	270,544	1,646,076
4		6944 - Pebble Lime	-	-	-	-	-	-	-	-	-	-	-	-	-
5		2001 - Chemicals (ACI)	-	-	-	-	-	-	-	-	-	-	-	-	-
6	R M Schahfer Gen Station	26940 - Purchase Ammonia	103,728	(0)	49,768	60,993	131,886	78,311	50,362	153,547	119,823	124,897	68,760	74,351	1,016,424
7		26957 - Purchase Dibasic Acid	126,000	187,275	33,109	94,593	79,137	142,583	204,012	139,297	127,270	124,160	116,001	100,879	1,474,316
8		26966 - Purchase Limestone	861,840	623,366	516,144	710,474	690,866	995,606	940,232	966,041	923,228	738,304	816,567	1,195,879	9,978,547
9		27225 - AMMONIA EXPENSE	94,894	79,154	-	77,672	99,298	127,692	180,182	134,809	54,265	4,759	68,481	83,653	1,004,860
10		2001 - Chemicals (ACI)	68,000	283	-	-	-	-	-	-	61,852	185,486	123,442	184,842	623,905
11		**Total**	**$ 1,731,109**	**$ 1,270,183**	**$ 870,052**	**$ 1,062,324**	**$ 686,270**	**$ 1,532,752**	**$ 1,449,085**	**$ 1,416,485**	**$ 1,440,583**	**$ 1,353,056**	**$ 1,267,349**	**$ 1,910,148**	**$ 15,989,396**

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2021
Nontrackable Fuel Handling - Account 50100000 - Fuel for Steam Production

Line No.	Segment	Cost Element	2021 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2021
1	E	3009 - Operations Services	$ 55,232	$ 227,412	$ 119,379	$ (462,853)	$ 1,695	$ 85,805	$ 145,142	$ 167,291	$ (131,656)	$ (14,294)	$ (116,229)	$ (100,150)	$ (23,225)
2	E	3021 - Env Health and Safety Services	-	-	-	507,184	44,399	46,094	-	131,899	447,084	153,324	298,382	182,154	1,810,520
3	E	3022 - Generation Constr Maint Svcs	-	-	-	-	-	20,150	-	6,503	-	-	-	-	26,653
4	E	3621 - Miscellaneous Revenue Billings	-	-	(67,415)	-	(48,170)	-	-	(6,707)	(19,029)	-	(3,398)	(11,549)	(156,269)
5	E	3861 - Non-Trackable	1,334,801	2,427,101	1,709,109	1,719,828	2,460,089	2,813,571	3,190,836	3,024,132	1,998,866	1,898,111	776,352	731,661	24,084,458
6	E	5010 - Facility Maint_Repair Svcs	105,229	-	-	-	-	-	-	-	-	-	-	-	105,229
7		**Total Nontrackable Fuel Handling**	$ 1,495,262	$ 2,654,513	$ 1,761,073	$ 1,764,159	$ 2,458,013	$ 2,965,620	$ 3,335,978	$ 3,323,118	$ 2,295,265	$ 2,037,141	$ 955,108	$ 802,116	$ 25,847,365
8															

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2020
Nontrackable Fuel Handling - Account 50100000 - Fuel for Steam Production

Line No.	Segment	Cost Element	January 2020	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended 12/31/200
1	E	3009 - Operations Services	$ 149,128	$ 203,083	$ 153,501	$ (671,615)	$ 34,049	$ 33,768	$ 22,543	$ 113,041	$ 242,243	$ (286,726)	$ 201,878	$ (278,017)	$ (83,124)
2	E	3021 - Env Health and Safety Services	-	-	-	-	-	-	-	-	-	-	-	-	-
3	E	3022 - Generation Constr Maint Svcs	-	-	-	-	-	-	-	-	-	-	-	-	-
4	E	3621 - Miscellaneous Revenue Billings	(11,827)			(22,273)	(19,569)	(50,914)			(61,111)	-	(19,592)	(19,911)	(205,196)
5	E	3861 - Non-Trackable	1,751,820	1,110,631	863,410	761,732	332,396	1,082,064	1,861,686	1,589,096	1,047,887	1,168,963	982,355	1,049,818	13,601,857
6	E	5010 - Facility Maint_Repair Svcs				802,101	158,863	(79,793)	135,421	120,223		468,093		383,240	1,988,147
7		**Total Nontrackable Fuel Handling**	$ 1,889,122	$ 1,313,714	$ 1,016,910	$ 869,945	$ 505,739	$ 985,124	$ 2,019,649	$ 1,822,360	$ 1,229,018	$ 1,350,330	$ 1,164,641	$ 1,135,130	$ 15,301,684
8															

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2019
Nontrackable Fuel Handling - Account 50100000 - Fuel for Steam Production

Line No.	Segment	Cost Element	2019 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2019
1	E	3009 - Operations Services	$ 184,697	$ (59,326)	$ (25,491)	$ 392,295	$ 76,048	$ 146,647	$ 53,109	$ 43,244	$ 39,631	$ 61,988	$ 134,488	$ 66,233	$ 1,113,563
2	E	3021 - Env Health and Safety Services	-	-	-	-	-	-	-	-	-	-	-	-	-
3	E	3022 - Generation Constr Maint Svcs	-	-	-	-	-	-	-	-	-	-	-	-	-
4	E	3621 - Miscellaneous Revenue Billings	(33,633)	(30,351)	(26,890)	(12,336)		(12,541)	(9,911)	(19,079)				(19,143)	(163,883)
5	E	3861 - Non-Trackable						(12,541)							(12,541)
6	E	5010 - Facility Maint_Repair Svcs	1,617,186	805,519	1,356,290	1,139,496	1,262,315	2,699,183	2,296,045	1,322,315	908,916	699,666	1,183,786	977,742	16,268,459
7		**Total Nontrackable Fuel Handling**	$ 1,768,251	$ 715,842	$ 1,303,909	$ 1,519,455	$ 1,338,363	$ 2,820,748	$ 2,339,243	$ 1,346,481	$ 948,547	$ 761,654	$ 1,318,274	$ 1,024,832	$ 17,205,599

Northern Indiana Public Service Company LLC
Twelve Months Ended December 31, 2018
Nontrackable Fuel Handling - Account 50100000 - Fuel for Steam Production

Line No.	Segment	Cost Element	2018 January	February	March	April	May	June	July	August	September	October	November	December	Twelve Months Ended December 31, 2018
1	E	3009 - Operations Services	$ 399,156	$ 239,956	$ 268,390	$ (40,501)	$ 147,584	$ 103,840	$ 138,344	$ 8,713	$ 14,075	$ 237,636	$ 448,309	$ 200,527	$ 2,166,029
2	E	3021 - Env Health and Safety Services	-	-	-	-	-	-	-	-	-	-	-	-	-
3	E	3022 - Generation Constr Maint Svcs	-	-	-	-	-	-	-	-	-	-	-	-	-
4	E	3621 - Miscellaneous Revenue Billings		(44,757)	(78,901)	(44,837)	(53,450)	(30,415)	(10,529)	(20,598)	(10,159)		(13,192)	(19,296)	(326,135)
5	E	3861 - Non-Trackable	2,946,170	1,525,571	2,244,003	1,818,279	3,306,750	2,297,284	2,203,436	2,339,729	2,036,703	1,757,694	1,692,806	2,465,162	26,633,586
6	E	5010 - Facility Maint_Repair Svcs	-	-	-	-	-	-	-	-	-	-	-	-	-
7		**Total Nontrackable Fuel Handling**	$ 3,345,326	$ 1,720,770	$ 2,433,492	$ 1,732,941	$ 3,400,885	$ 2,370,709	$ 2,331,250	$ 2,327,844	$ 2,040,619	$ 1,995,329	$ 2,127,924	$ 2,646,392	$ 28,473,480

[redacted]

[redacted]

From:	nconlon@nisource.com
To:	Gardner, Nicole
Cc:	Hamblin, Richard; Gavin, Brad
Subject:	NIPSCO Units 14 and 15 retirement
Date:	Wednesday, October 13, 2021 3:43:27 PM

**** This is an EXTERNAL email. Exercise caution. DO NOT open attachments or click links from unknown senders or unexpected email. ****

Ms. Gardner,

I've cc'd your peers since you are out of the office this week

This communication hereby informs the IDEM OWQ Industrial Permitting office that, effective 1-October-2021 Units 14 and 15 located at the R.M. Schahfer Generating Station (Station) with NPDES permit IN0053201 have been officially retired. This is simply a courtesy notification so IDEM can update their files regarding the change at RSMGS.

Units 17 and 18 at the Station remain operational. Continuation of NPDES permit IN0053201 is required in support of ongoing activities at the Station through the future retirement of the facility. As previously submitted to the Department, coal fired generation at the Station is currently scheduled to cease in 2023. Accordingly, NIPSCO maintains the retirement of Units 14 and 15, while reducing the electric generating capacity of the Schahfer Generating Station, does not warrant permit modification, revocation, re-issuance, nor termination as addressed in 327 IAC 5-2-16.

Thank you for your attention to this matter.
If you have any questions, please do not hesitate to contact me.

Regards,
Natalie Conlon
Natural Resources Permitting Principal
NIPSCO
nconlon@nisource.com
Work: 219.647.5251
Mobile: 219.742.5633

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

Cynthia M. Armstrong
Chief Technical Advisor Indiana Office of
Utility Consumer Counselor

Cause No. 45772
NIPSCO
1/20/2023

Certificate of Service

This is to certify that a copy of the Indiana Office of Utility Consumer Counselor's Testimony Filing has been served upon the following parties of record in the captioned proceeding by electronic service on January 20, 2023.

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