Commissioner	Yes	No	Not Participating
Huston			√
Bennett	√		
Freeman	√		
Veleta	√		
Ziegner	√		

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR APPROVAL OF (1) A FUEL COST ADJUSTMENT TO BE APPLICABLE DURING THE BILLING CYCLES OF MAY, JUNE, AND JULY 2025, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NOS. 45772, (2) RATEMAKING TREATMENT FOR THE COSTS INCURRED UNDER WHOLESALE PURCHASE AND SALE AGREEMENTS FOR WIND AND SOLAR ENERGY APPROVED IN CAUSE NOS. 45194, 45195, 45310, 45462, 45524, AND 45541, AND (3) AN UPDATED HEDGING PLAN, INCLUDING RECOVERY OF CERTAIN COSTS ASSOCIATED WITH THAT PLAN, PURSUANT TO IND. CODE § 8-1-2-42(d).	)	**CAUSE NO. 38706 FAC 146** **APPROVED: APR 30 2025**

ORDER OF THE COMMISSION

Presiding Officers:
Kehinde Akinro, Administrative Law Judge

On February 18, 2025, Northern Indiana Public Service Company LLC ("NIPSCO" or "Petitioner") filed a Verified Petition in this Cause. NIPSCO concurrently filed its case-in-chief.

On February 21, 2025, the NIPSCO Industrial Group ("Industrial Group") filed a petition to intervene. This petition was granted on March 4, 2025.[1]

On March 25, 2025, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its case-in-chief.

An evidentiary hearing in this Cause was held at 10:30 a.m. on April 10, 2025, in Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the Industrial Group, by counsel, participated in the hearing, and the testimony and exhibits of NIPSCO and the OUCC were admitted without objection.

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

1. **Commission Jurisdiction and Notice.** Notice of the evidentiary hearing was published as required by law. NIPSCO is a public utility as defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to NIPSCO's fuel cost

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[1] The members of the Industrial Group in this proceeding are Cleveland-Cliffs Steel LLC, Jupiter Aluminum Corporation, Linde, Inc., United States Steel Corporation, and USG Corporation.

charge. Therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this Cause.

2. **NIPSCO's Characteristics.** NIPSCO is a limited liability company organized under Indiana law with its principal office in Merrillville, Indiana. NIPSCO renders electric public utility service in Indiana and owns, operates, manages, and controls, among other things, plant and equipment within Indiana used for the production, transmission, delivery, and furnishing of such service.

3. **Available Data on Actual Fuel Costs.** NIPSCO's cost of fuel to generate electricity, and the cost of fuel included in the cost of purchased electricity in NIPSCO's most recent base rate case approved in the Commission's August 2, 2023 Order in Cause No. 45772 ("45772 Order") was $0.033674 per kilowatt hour ("kWh"). NIPSCO's cost of fuel to generate electricity, and the cost of fuel included in the cost of purchased electricity for the months of October, November, and December 2024 averaged $0.037823 per kWh.

4. **Requested Fuel Cost Charge.** NIPSCO seeks to change its fuel cost adjustment from the current fuel cost factor credit of 0.001759 per kWh for bills rendered during the February, March, and April 2025 billing cycles to a fuel cost charge of $0.001157 per kWh for bills rendered during the May, June, and July 2025 billing cycles or until replaced by a different fuel cost adjustment approved in a subsequent filing.

The requested fuel cost adjustment includes federal Investment Tax Credits and Production Tax Credits of $2,895,577 (Sch. 1, Ln. 41) and an under-collected variance of $15,427,240 during October, November, and December 2024 ("reconciliation period"). NIPSCO's estimated monthly cost of fuel to be recovered in this proceeding for May, June, and July 2025 ("forecast period") is $25,474,727, and its estimated monthly average sales for that period are 851,309 megwatt-hours ("MWhs").[2]

5. **Statutory Requirements.** Ind. Code § 8-1-2-42(d) states that the Commission shall grant a fuel cost adjustment charge if it finds:

(1) the electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible;

(2) the actual increases in fuel cost through the latest month for which actual fuel costs are available since the last order of the commission approving basic rates and charges of the electric utility have not been offset by actual decreases in other operating expenses;

(3) the fuel adjustment charge applied for will not result in the electric utility earning a return in excess of the return authorized by the Commission in the last proceeding in which the basic rates and charges of the electric utility were approved. However, subject to section 42.3 [Ind. Code § 8-1-2-42.3], if the fuel charge applied for will result in the electric utility earning

[2] The average cost of fuel and estimated monthly average sales to be recovered in this proceeding for the forecasted billing period of May, June, and July 2025 are based on the estimated averages for April, May, and June 2025 as shown on Schedule 1.

a return in excess of the return authorized by the commission in the last proceeding in which basic rates and charges of the electric utility were approved, the fuel charge applied for will be reduced to the point where no such excess of return will be earned; and

(4) the utility's estimate[s] of its prospective average fuel costs for each such three calendar months are reasonable after taking into consideration:

(A) the actual fuel costs experienced by the utility during the latest three calendar months for which actual fuel costs are available; and

(B) the estimated fuel costs for the same latest three calendar months for which actual fuel costs are available.

6. __Fuel Costs and Operating Expenses__. NIPSCO's Attachment 1-F shows fuel costs for the 12 months ending December 31, 2024, were $13,472,485 above the amount the Commission approved in Cause Nos. 45159 and 45772. NIPSCO's Attachment 1-F to Petitioner's Exhibit 1 also shows its total operating expenses, excluding fuel, for the 12 months ending December 31, 2024, were $16,196,703 above the amounts approved in the 45159 and 45772 Orders. The Commission finds there have been increases in NIPSCO's actual fuel costs for the 12 months ending December 31, 2024, that have not been offset by actual decreases in other operating expenses.

7. __Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost__. John Wagner, Manager, Fuel Supply for NIPSCO testified that NIPSCO made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. He testified that during the reconciliation period, of the energy produced by NIPSCO's fossil-fueled generation, NIPSCO's coal-fired generation provided 28.0% of energy generated and 72.0% of the energy generated was gas-fired. He stated NIPSCO's coal-fired generation consumes coal from various supply regions, with a mix of Powder River Basin ("PRB") and Northern Appalachian ("NAPP") coal consumed at the Michigan City Generating Station ("Michigan City"), and Illinois Basin ("ILB") coal is consumed in Unit 17 and 18 at R.M. Schahfer Generating Station ("Schahfer").

A. __Fuel Procurement__. In discussing NIPSCO's coal procurement process, Mr. Wagner identified several factors NIPSCO considers when evaluating purchases for a specific generating unit, including the delivered cost, operational costs, cost of emission controls, and management of coal combustion byproducts. In addition, a coal's combustion and emission characteristics are critical and may eliminate a coal from consideration if these characteristics adversely affect a generating unit's reliability, increase the total cost of generation (fuel and operational costs) or inhibit the ability to comply with emission limits. He testified the reliability of the coal source and the reliability of coal transportation from that source are also critical factors NIPSCO considers.

Mr. Wagner stated NIPSCO had three supply contracts that were effective during the reconciliation period. These contracts were with Arch Coal Sales Company for PRB coal; American Consolidated Natural Resources for NAPP coal; and Peabody COALSALES, LLC for

ILB coal. Mr. Wagner confirmed that NIPSCO has no financial interest in the coal producers currently under contract.

Mr. Wagner testified NIPSCO amended a transportation agreement with the Chicago South Shore Railroad to extend service for Michigan City into 2025. In addition, NIPSCO worked with Peabody to settle the 2024 tonnage shortfall issue. He stated that as is industry standard, NIPSCO's ILB coal supply agreement with Peabody includes a minimum tonnage obligation. He stated that because NIPSCO did not meet the 2024 minimum tonnage obligation and consistent with past practices, NIPSCO negotiated a contract amendment to address the tonnage shortfall. He stated NIPSCO paid Peabody a portion of the liquidated damage payment obligation in December 2024 which was expensed in December. He stated the balance was amortized over the remaining tonnage and will be paid as part of the 2025 contract price. He sponsored Confidential Attachment 3-A showing that the customer benefits exceed the cost of this payment obligation.

Mr. Wagner testified the settlement resulting in the contract amendment negotiated with Peabody is reasonable and prudent. He stated that to reach settlement, NIPSCO examined different options to find the lowest cost solution to manage its coal inventory at a level that is safe for operations. He explained this was undertaken as part of the Petitioner's ongoing "effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible."[3] He stated the original agreement with Peabody was executed after following NIPSCO's coal procurement process and the volume under that agreement was anticipated to provide a portion of the future delivery requirements at a cost that was below market at the time of the transaction. He said the drastic change in market conditions after execution of that agreement resulted in a long position and NIPSCO was forced to reduce coal shipments that ultimately led to the shortfall in the minimum volume obligation. He stated this is consistent with a past Commission order noting that "coal is not a just-in-time delivered commodity and therefore is planned months and, in many cases, years in advance based on modeling of expected burn at the point in time purchase decisions are made."[4]

Mr. Wagner testified NIPSCO's coal supply cost, including the liquidated damages, was prudently incurred. He stated it was also the lowest cost option and ultimately minimized customer cost. He explained that NIPSCO's offer strategy uses the replacement cost of fuel (sometimes referred to as market-based dispatch) and is consistent with the offer methodologies used for NIPSCO's other generating assets (e.g. Sugar Creek combined cycle unit), which establishes market-based economics of either consuming fuel or keeping the unit in economic reserve and purchasing power. He stated that under this methodology, if the unit does not clear the Midcontinent Independent System Operator ("MISO") day-ahead market (i.e. does not operate), it is in the best interest of customers to forgo consuming coal and settling with the supplier and/or selling the coal. He said the replacement cost of coal is estimated to be the cost to purchase the coal at market which is also the proxy price used to calculate liquidated damages.

Mr. Wagner described alternatives NIPSCO considered including: (1) carrying the shortfall tonnage in inventory, which would have increased 2024 year-end inventory to 69 days (172% of the 40-day target) and (2) carrying the inventory at alternative locations. However, keeping

[3] Ind. Code § 8-1-2-42(d)(1).

[4] *AES Indiana*, Cause No. 38703 FAC 143 at 15 (IURC May 29, 2024).

inventory above the 40-day target is not practical in the long-run for several reasons. The first reason is safety, the size of the pile and the ability to physically handle and maintain that level of inventory can create physical hazards and cause potential environment concerns. The second reason is the incremental cost of holding excess inventory far exceeds any reliability benefits, especially when energy prices are low. The last reason is that, given the impending retirement of Schahfer Units 17 and 18 at the end of 2025, higher inventory levels could result in more forced burn which could be uneconomic. In addition, higher inventories increase the risk of having substantial amounts of coal remaining in inventory after the units are retired, which could ultimately increase FAC expense and/or inventory disposal/environmental clean-up costs.

He stated NIPSCO also evaluated potentially deferring the tonnage, stating that Peabody is under no obligation to allow the deferral of tonnage. He said that assuming Peabody would agree to the deferral of tonnage into 2025, this option was not feasible as consumption estimates indicated NIPSCO would not meet future obligations. Therefore, deferring the tonnage simply would have added to the 2025 long position. He explained that NIPSCO's plan to retire Schahfer Units 17 and 18 by the end of 2025 is well known, which leaves little expectation that NIPSCO will "make up" the 2024 shortfall tonnage in addition to meeting the 2025 minimum tonnage obligation remaining under the agreement. He stated that under the terms of the agreement, Peabody could also have demanded payment of liquidated damages as a lump sum, but NIPSCO was able to negotiate a portion of the liquidated damages payment over the remaining term of the agreement to further benefit customers.

Mr. Wagner stated that as a result of NIPSCO's efforts, customers benefited from NIPSCO's lower cost MWhs from natural gas resources and/or lower purchased power prices. Confidential Attachment 3-A shows an estimated reduction in customer fuel cost of roughly $13.2 million as well as $230,956 resulting from NIPSCO negotiating a lower settlement rate and deferral of the lump sum payment to Peabody for a total estimated customer benefit of roughly $13.4 million. He concluded that paying liquidated damages under the Peabody coal contract was a prudent decision made in the interest of customers, and Confidential Attachment 3-A reasonably estimates the resulting customer benefits and savings.

Mr. Wagner stated that NIPSCO's offer strategies and actions taken were consistent with the FAC (d)(1) test which directs the electric utility to make "every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible." Furthermore, NIPSCO did not focus only on the coal units, but considered all reasonable supply options as market conditions change, including its other generation resources and purchased power options. Ultimately, paying liquidated damages under its coal supply contract was the lowest cost option and provided NIPSCO's customers with the lowest fuel cost reasonably possible.

OUCC witness Michael D. Eckert, Director of the OUCC's Electric Division, stated that the OUCC views the recovery of liquidated damages as improper in an FAC proceeding but recognizes the Commission has relatively recently, over the OUCC's objections, approved the inclusion of liquidated damages in FAC trackers for AES Indiana in Cause No. 38703 FAC 143 and NIPSCO in Cause No. 38706 FAC 143. Based on those Orders, the OUCC is not opposing the liquidated damage recovery NIPSCO requests in this FAC. The OUCC did recommend, however, that NIPSCO be ordered to update the Commission in its FAC filings upon all liquidated damages paid, including the amount paid and when such amounts were paid and expensed.

Mr. Wagner stated that producers and customers are generally reluctant to execute longer term contracts with fixed prices without some type of market price adjustment mechanism. He opined that maintaining a price close to market is beneficial to both parties, therefore, a producer and customer may work together to establish an equitable price adjustment methodology. Mr. Wagner stated that, historically, market-based price adjustments in term supply agreements tend to reduce the buyer's cost of hedging since future prices are generally higher than spot and year-ahead prices. In addition to base price adjustments, quality price adjustments are used to maintain the underlying economics of the agreement on a dollar per million British thermal unit ("Btu") basis when the shipment quality varies from guaranteed quality specifications, and that other price adjustments can occur due to governmental imposition (e.g., federal or state agencies levy taxes or change rules that increase the cost of mining or production) or the payment of damages. Mr. Wagner stated that one of NIPSCO's term coal contracts in effect during the reconciliation period had mostly fixed prices specified in the contract, and a portion of the volume under this agreement was priced using a coal market index. In addition, all of NIPSCO's coal supply agreements adjust the price of coal based on a shipment's quality variances from contract specifications.

Mr. Wagner testified the cost of coal consumed for NIPSCO for the 12 months ending December 31, 2024, was $80.40 per ton, or $3.817 per million Btu. The cost of coal consumed during the reconciliation period was $96.19 per ton, or $4.399 per million Btu. When compared to the prior reconciliation period, Mr. Wagner stated NIPSCO's delivered cost of coal consumed per ton increased by $18.99 and $0.718 per million BTU. Mr. Wagner testified the main driver of the increase was a significant change in the mix of coals consumed during the reconciliation period when compared to the prior quarter. Specifically, during the reconciliation period, Schahfer consumed 95.2% of tonnage and Michigan City consumed 4.8% of total system tonnage, versus 57.0% and 43.0%, respectively. The cost of ILB coal is higher than the mix of coals used at Michigan City. Railroad fuel surcharges declined as average on-highway diesel fuel prices fell by 3.8% when compared with the prior quarter, which offset some of the increase. PRB and NAPP delivered prices declined and ILB delivered costs were up when compared to the reconciliation.

Christina P. Hook, Manager of Market Settlements for NIPSCO described NIPSCO's two distinct processes for purchasing natural gas for electric generation: (1) purchasing gas as a large transport customer under Rate 328 from NIPSCO's gas local distribution company and (2) procuring natural gas for NIPSCO's Sugar Creek combined cycle plant, which is located on a Midwestern Gas Transmission interstate pipeline. She also described the general advantages of each arrangement. She further testified that NIPSCO has made every reasonable effort to purchase natural gas to provide electricity at the lowest reasonable price.

Based on the evidence presented, the Commission finds NIPSCO has adequately explained its coal and gas procurement decision making, and its acquisition process, including the payment of liquidated damages described in NIPSCO witness Wagner's testimony, is reasonable.

B. <u>Coal Decrement Pricing</u>. Mr. Wagner testified NIPSCO is not currently utilizing decrement pricing but will continue to update the Commission about decrement pricing in its future FAC filings.

Mr. Eckert stated that if coal decrement pricing is used in the future, NIPSCO provide justification and documentation supporting the need for, and utilization of, coal decrement pricing and specify when it expects the coal decrement pricing to end, as well as provide inputs to its calculation of the coal price decrement.

The Commission finds, based on the evidence, that decrement pricing is not included in NIPSCO's forecast for purposes of this FAC proceeding. If coal decrement pricing is included in NIPSCO's forecast or has been used, NIPSCO shall file testimony, schedules, and workpapers in its future FAC proceedings addressing any need for and the reasonableness of any utilization of coal decrement pricing and shall provide inputs to its calculation of the coal price decrement consistent with the Commission's July 17, 2019 Order in Cause No. 38706 FAC 123.

C. Renewable Energy Credits ("RECs"). Ms. Hook provided an update on NIPSCO's treatment of RECs associated with its energy purchases under wind and solar purchased power agreements ("PPAs"). She testified that pursuant to the Commission's (1) August 7, 2019 Order in Cause No. 45194 ("45194 Order"), NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Rosewater on November 20, 2020; (2) June 5, 2019 Order in Cause No. 45195 ("45195 Order"), NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Jordan Creek on December 2, 2020; (3) February 19, 2020 Order in Cause No. 45310 ("45310 Order"), NIPSCO began receiving power, and seeking recovery of costs associated with the wholesale purchase, and sale agreement for wind energy from Indiana Crossroads Wind Generation LLC on December 17, 2021; (4) May 5, 2021 Order in Cause No. 45462 ("45462 Order"), NIPSCO began receiving power, and seeking recovery of costs associated with the wholesale purchase, and sale agreement for solar energy from Dunn's Bridge I Solar Generation LLC on August 4, 2023; (5) July 28, 2021 in Cause No. 45524 ("45524 Order"), NIPSCO began receiving power, and seeking recovery of costs associated with the wholesale purchase, and sale agreement for solar energy from Indiana Crossroads Solar Generation LLC on August 9, 2023; and (6) September 1, 2021 Order in Cause No. 45541 ("45541 Order"), NIPSCO began receiving power, and seeking recovery of costs associated with the wholesale purchase, and sale agreement for wind energy from Crossroads Wind II on December 22, 2023. She testified that pursuant to the Commission's May 5, 2021 Order in Cause No. 45472 ("45472 Order"), NIPSCO anticipates receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for solar energy from Green River Solar in June 2025. Consistent with the 45194, 45195, 45310, 45462, 45524, and 45541 Orders, NIPSCO is also crediting any off-system sales created by its wind and solar PPAs. For the reconciliation period, NIPSCO received 245,357 MWhs (October), 319,903 MWhs (November), and 344,628 (December). The OSS Adjustment for the forecast period is included on Attachment 1-A to Petitioner's Exhibit 1.

Ms. Hook stated that each megawatt hour of power generated from a qualified resource can be awarded a REC. Because no national standard currently exists, she stated each jurisdiction has set its own regulations upon how to qualify and account for RECs. Ms. Hook stated that NIPSCO receives RECs associated with the power it purchases from Jordan Creek, Rosewater, Crossroads Wind, Dunn's Bridge I, Crossroads Solar, and Crossroads Wind II. She stated that as of this filing, NIPSCO receives RECs associated with the power it generates from Cavalry Solar. She explained all RECs are and will be tracked in a renewable energy tracking system. During this FAC period, Ms. Hook stated that current vintage RECs were sold with the block size and proceeds from the sales as follows:

Transaction	RECs Sold	Net Proceeds
1	50,000	$ 127,500
2	50,000	$ 130,513
3	100,000	$ 246,250
4	98,660	$ 242,950
5	50,000	$ 132,500
6	50,000	$ 137,900
7	75,000	$ 195,000
8	52,477	$ 155,070
9	50,000	$ 160,063
10	50,000	$ 128,050
11	39,598	$ 102,955
12	25,000	$ 64,025
Total	690,735	$ 1,822,775

Ms. Hook testified that NIPSCO has passed and anticipates continuing to pass the proceeds from the sale or transfer of RECs back to its customers through the "Purchased Power other than MISO" line item. Per Ms. Hook NIPSCO continually monitors and evaluates the marketability for all RECs, and as the possibility for future legislation evolves, NIPSCO will make appropriate changes to its REC strategy.

Ms. Hook stated that during the reconciliation period, NIPSCO had 27 approved solar and wind customers with facilities registered in M-RETS, with nameplate capacities ranging between 0.05 MW and 2.0 MW. Solar and wind generation volumes are uploaded to M-RETS monthly. During this FAC period, Ms. Hook testified no current vintage solar and wind feed-in tariff ("FIT") RECs were sold.

Ms. Hook stated NIPSCO has and anticipates continuing to pass the proceeds from the sale of FIT RECs back to customers through the "Purchased Power other than MISO" line item. She noted NIPSCO continues to have discussions with brokers and market participants to determine the best means of marketing the FIT RECs.

Ms. Hook stated that NIPSCO did not enter any third-party energy transactions for physical power that are reflected in the forecast period. She stated that NIPSCO did not enter into any third-party energy transactions for physical power that impacted the reconciliation period, however, NIPSCO will continue to consider entering into short-term, third-party agreements for purposes of protecting customers from market influences.

Ms. Hook stated that NIPSCO incorporated forecasted FIT purchases in this filing. She explained that NIPSCO projects FIT purchases for the forecast period based on the average actual FIT purchases incurred for the 12-month period ending December 31, 2024.

Ms. Hook stated NIPSCO has incorporated REC sales and Joint Venture ("JV") cash distributions for the forecast period and explained the credit for forecasted REC sales is based on the average of actual REC sales for the 12-month period ending December 31, 2024. She stated that the credit for forecasted JV cash distributions is based on the average of actual JV cash distributions credited to the FAC customer for the 12-month period ending December 31, 2024.

The Commission finds that NIPSCO shall continue to include in its quarterly FAC filings updates concerning its utilization of RECs associated with wind and solar purchases being recovered through the authority granted in 45194, 45195, 45310, 45462, 45524, 45541, and 45936 Orders and any other future renewable purchases. NIPSCO shall also continue to incorporate forecasted REC sales and quarterly JV cash distributions using the forecasting methodology employed in this Cause.

D. Electric Hedging Program. Ms. Hook testified NIPSCO is operating under the updated 2024-2026 Hedging Plan ("Hedging Plan"), which began in July 2024, and that the following hedging contracts were purchased during the reconciliation period:

	Power Contracts		Gas Contracts	
Month	**Actual**	**Var to Plan**	**Actual**	**Var to Plan**
October 2024	55	0	38	0
November 2024	25	0	36	0
December 2024	10	0	38	0

Ms. Hook stated the execution of these contracts is consistent with the Hedging Plan through December 31, 2024. She explained that there are no other changes to the Hedging Plan and to the extent NIPSCO updates its plan further, future FAC filings will disclose any additional deviations from the approved plan.

Ms. Hook stated that the impact of the hedges entered into for the Hedging Plan during the reconciliation period was a loss of $778,888, with the net total impact (including broker and clearing exchange fees) of $787,529. Broker fees represented 0.10% of the total value of the transactions occurring during the reconciliation period. Ms. Hook stated that decisions were made based upon the conditions known at the time of the transactions, and NIPSCO used the same broker it uses for other transactions to limit transaction costs, with the transactions all made in accordance with NIPSCO's Commission-approved Hedging Plan. She stated NIPSCO will continue to solicit input and work with interested stakeholders on any potential changes to its Hedging Plan as NIPSCO's generating portfolio continues to transition.

Mr. Eckert testified that the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs are reasonable. He affirmed that NIPSCO entered into 112 gas and 90 power contracts during the three-month period under review.

The Commission finds that NIPSCO shall continue to include in its FAC filings testimony and evidence of its electric hedging costs and any gains/losses resulting from hedging transactions for which NIPSCO seeks recovery through the FAC.

8. **MISO Day 2 Energy Costs.** NIPSCO included in its forecast the operational changes associated with the MISO Day 2 energy market in accordance with the Commission's Orders in Cause Nos. 42685, 43426, and 43665. The total MISO Components of Cost of Fuel included in the actual cost of fuel for October, November, and December 2024 was $10,823,396.

Ms. Hook testified the Real Time Non-Excessive Energy was $2,920,743 in October 2024 and $1,799,201 in November 2024, primarily driven by unit derates and forced outages that occurred after NIPSCO's units cleared in the Day Ahead market, as well as differences in actual wind production compared to forecast (due mainly to wind speeds). Ms. Hook testified the Day Ahead Marginal Congestion Component plus actual monthly Auction Revenue Rights/Financial Transmission Rights ("ARR/FTR") expenses, less actual monthly ARR/FTR revenues, did exceed a cost of $2 million in the reconciliation period. She stated the net monthly ARR/FTR expense was $7,481,306 in November 2024. She explained the primary driver is the high average congestion prices at NIPSCO's NIPS. NIPS node that exceeded the average by approximately 24 times for the period of January through October 2024. She said NIPSCO inquired of MISO as to the cause for the high congestion rates, to which MISO responded that they do not provide information on individual constraints being modeled in the Day Ahead market to manage congestion.

9. **Estimation of Fuel Cost.** NIPSCO estimates its total average fuel costs for May, June, and July 2025 will be $25,474,727 monthly.[5] Ms. Hook noted that NIPSCO incorporated forecasted known fixed transportation reservation charges and a related credit associated with Sugar Creek.

Mr. Wagner testified that as of January 31, 2025, NIPSCO's estimated free-on-board ("F.O.B.") mine spot market prices for delivery during the forecast period were $14.15 per ton for PRB coal, $41.50 per ton for ILB coal, and $52.50 per ton for NAPP coal. Mr. Wagner testified that market dynamics appear to have put downward pressure on coal demand globally and should ease supply constraints for coal-fired utility generators in 2025 and into 2026. He stated there are multiple factors that may impact supply and demand during the forecast period including, but not limited to, power prices, natural gas prices, railroad and coal supplier performance, generating unit performance, weather conditions, and labor disruptions. Regarding NIPSCO's supply and demand, contracted purchases are expected to meet most of NIPSCO's 2025 forecasted coal delivery requirements and coal producers are obligated to perform under these agreements. He noted that NIPSCO has had discussions with all its coal suppliers in which the suppliers indicated they will meet NIPSCO's contracted coal supply requirements. Regarding the cost of coal, the price of coal used for the forecast period consists of mostly fixed prices. One coal supply agreement has fixed prices and a portion of tonnage is priced at market. The agreement has minimum and maximum rates that ultimately hedge customer price exposure. If demand exceeds the forecast and current supply obligations, NIPSCO may need to purchase additional supply, which may impact fuel costs during the forecast period.

Mr. Wagner stated the average spot market price of coal during the reconciliation period, when compared to the prior reconciliation period, was $13.97 per ton (up $0.19) for PRB coal,

[5] The estimated total average fuel costs for April, May, and June 2025 as shown on Schedule 1 is used to calculate the amounts to be recovered in this proceeding for the forecasted billing period of May, June, and July 2025.

$39.00 per ton (up $3.00) for ILB coal, and $50.33 per ton (up $0.75) for NAPP coal. He stated these are average F.O.B. mine spot market prices only, which do not include the cost of transportation, and actual prices may vary from published indices.

In identifying energy market trends and factors affecting the market for coal and transportation during the reconciliation period, Mr. Wagner stated wholesale electricity prices were roughly 23% higher during the reconciliation period when compared with the same period in 2023. Overall energy market conditions remained relatively soft as low natural gas prices and increasing renewable generation reduced coal demand. However, summer conditions did drive up electricity usage in the U.S. and coal burn increased relative to the prior quarter. The U.S. Energy Information Administration ("EIA") projects the U.S. electric energy supply mix for 2024 and 2025 in its latest outlook as follows: (1) Renewable generation (including hydro) provided 22% of the nation's energy mix in 2024 and is expected to provide 25% in 2025 and 27% in 2026; (2) nuclear comprised 19% of electric generation in 2024 and is expected to provide 19% of the mix in 2025 and 2026; (3) natural gas-fired generation provided 43% of the mix and is expected to provide 41% and 40% in 2025 and 2026 respectively; (4) coal-fired generation provided 16% of the energy in 2024 and is expected to provide 15% of the mix in 2025 and 2026; and (5) U.S. coal production decreased by 12% in 2024 when compared with 2023 levels and is expected to fall another 6% in 2025 and remain flat in 2026.

Henery Hub spot pricing averaged $2.28 per MMBTU during 2024 and is expected to rebound to $3.10 in 2025 and increase to $4.00 in 2026. Illinois Basin coal prices are up roughly 18% and PRB prices are up 2% when compared to year-ago levels.[6] Despite the modest increases in coal prices, low natural gas prices and increasing renewable generation has kept coal-fired generation as the marginal energy source and this dynamic is expected to continue and will likely keep soft coal pricing and limit price volatility. NIPSCO expects coal demand will continue to fall in the long run driven by low natural gas prices and increased renewable production as coal generation is phased out of domestic energy markets.

Mr. Wagner testified these dynamics have continued to keep prices soft in all energy markets during the reconciliation period. He said that coal pricing into Europe (delivered to ARA) fell precipitously during 2023. API 2 prices were bottomed out in May 2024 and were roughly 3% lower year over year during the reconciliation period. In addition, coal producers and railroads have typically relied on strong international markets to offset the long-term decline in domestic demand and export markets have provided relatively steady sales opportunities during the year. The EIA reported coal exports to reach 107.5 million tons in 2024 (five-year high) and expects exports to fall back to 103.9 million tons in 2025. Overall, the outlook for global coal use is somewhat bullish and export opportunities are expected to remain steady or improve. Mr. Wagner testified that railroad performance has been relatively stable but that reduced investment in coal production and coal transportation projects, supplier bankruptcies, and mine closures over the last several years, have caused coal supply chain constraints, which may lead to market volatility if energy prices, and demand rebound. In addition, variable coal demand impacts supply chain efficiency and can lead to unpredictable railroad performance.

[6] *NIPSCO Over-The-Counter price assessment*

Mr. Wagner stated that NIPSCO's estimate for the cost of coal consumed for generation in the forecast period is $90.33 per ton or $4.263 per million BTU.

Mr. Wagner stated that in developing the estimate for the forecast period, NIPSCO's fuel supply group incorporates coal contract prices inclusive of adjustments specified in the agreement, dust treatment costs, freeze conditioning costs (seasonal), railcar lease cost, railcar maintenance costs, estimates of contract prices (fixed prices and indexed contract rates using forward locational marginal price ("LMP") forecasts), transportation fuel surcharges using the monthly average price of U.S. On-Highway Diesel Fuel ("HDF"), the Association of American Railroad's All-Inclusive Index Less Fuel adjustments and estimates of future coal purchase prices. He stated that in addition, the fuel supply group provides a forecast of beginning inventory values in dollars and quantities in tons for each generating station. These assumptions are provided to NIPSCO's energy supply and optimization group to develop the forecast.

Ms. Hook testified that NIPSCO completed its forecast for this FAC filing on February 11, 2025, using its production cost modeling system, PROMOD,[7] and made reasonable decisions under the circumstances known at that point in time.

The Fuel Cost Factor is forecasted to be $29.924 compared to a Base Cost of Fuel of $33.674. Ms. Hook explained that in comparing FAC 146 to FAC 145, (1) combined cycle generation is projected to decrease on a total MWh basis, with a lower forecasted cost per MWh; (2) solar generation, solar energy purchases, and solar joint venture purchases are projected to increase in total MWh compared to the wind energy purchases and wind joint venture purchases, and the forecasted cost per MWh for solar is also projected to be lower..

Ms. Hook stated that to ensure NIPSCO provides electricity to its retail customers at the lowest fuel cost reasonably possible, NIPSCO utilized the approved Hedging Plan from FAC 142, which became effective July 1, 2024, and NIPSCO will continue to utilize financial hedges under the 2024 Hedging Plan to mitigate economic impacts and volatility within each FAC. Second, NIPSCO has added additional wind and solar resources and will continue to add new resources to its portfolio, which do not have variable fuel costs and are much cheaper relative to utilizing coal-fired (steam) generation. She stated NIPSCO will continue to utilize its ever-growing wind, solar, and solar plus storage fleet of assets to economically serve customers as well.

Mr. Wagner testified there are two key factors that could impact coal transportation costs during the forecast period. One factor, power prices, may impact coal transportation costs under two transportation contracts that are indexed to station LMPs. Contract transportation rates are forecasted using forward energy prices and have maximum rates that ultimately hedge price exposure. A second factor is the price of HDF. Two coal transportation agreements have mileage-based fuel surcharges (governed by each carrier's fuel surcharge tariff) that are calculated monthly using the average weekly spot price of HDF. Fuel surcharge estimates are included in rate projections used to develop comprehensive transportation costs for the forecast period. He stated that, for reference, the spot price of HDF as of January 27, 2025 was $3.659 per gallon. This is a 5.4% year-over-year decrease. The EIA expects that there will be downward pressure on oil prices over the next two years as production is expected to outpace demand. The EIA forecasts that diesel

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[7] PROMOD is NIPSCO's electric forecasting model.

prices will average $3.660 per gallon during 2025. Based on this outlook, fuel surcharges under NIPSCO's transportation agreements are expected to remain flat or trend modestly lower through the end of 2026.

Mr. Wagner testified NIPSCO is proactively administering coal and rail transportation agreements to address any potential coal supply and/or coal transportation shipment issues. In addition, all anticipated coal supply requirements for 2025 should be met under current coal supply and transportation agreements. Coal market demand has softened significantly over the past two years and the stress on the coal supply chain has been reduced. However, if coal demand increases, utilities may struggle to schedule deliveries as railroads and coal producers have rationalized assets, labor, and production, and it will take time for production and shipments to recover to meet any increase in demand. Notwithstanding, NIPSCO continues to work closely with its rail carriers to ensure coal deliveries meet demand during the forecast period.

Mr. Wagner stated the days of coal inventory supply at Schahfer was approximately 25 days (down four days from the prior quarter) at the end of the reconciliation period. He testified Michigan City's PRB coal inventory was at 33 days and the NAPP inventory was at 34 days at the end of the reconciliation period. Mr. Wagner testified NIPSCO has made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible.

Mr. Wagner testified NIPSCO's fleet size was 776 railcars (six 125-car sets with 3.5% spares) at the end of the reconciliation period. The typical spare railcar pool ranges between 3% and 8%. NIPSCO is actively collecting 2 railcars for return and expects to have these cars returned to lessors by the end of Quarter 1 of 2025. According to Mr. Wagner, during the reconciliation period, NIPSCO utilized roughly 41% of its railcar fleet. He explained that NIPSCO stored two sets at Schahfer during the reconciliation period. One set was stored at a third-party location during the reconciliation period. Storage of railcars was required from time to time during the reconciliation period as coal consumption continued to trend well below forecasted and historical rates that led to extended periods of economic reserve (idle coal units) driven by soft energy market conditions, strong renewable production, much better than expected railroad performance, planned and unplanned station maintenance outages, and high inventory levels. Coal consumption was roughly 21% of the system's maximum burn rate and railcar utilization exceeded the station generation utilization rates. NIPSCO continuously evaluates its railcar needs and considers demand/delivery requirements (forecasted, historical, and actual), railroad performance, station unloading performance, and the timing of lease expirations. NIPSCO determined that the fleet size should be held to roughly 774 railcars (six-unit trains with 3.3% spares) through the end of 2025. NIPSCO will continue to use commercially reasonable efforts to return the remaining cars to the lessor as soon as practicable while ensuring reliable coal deliveries.

Mr. Wagner stated that to mitigate railcar cost while balancing reliability, NIPSCO reduced the fleet size driven by coal unit retirements and has plans to reduce the fleet by 376 railcars when Schahfer Units 17 and 18 retire at the end of 2025. When demand varies and storage is required, NIPSCO standard practice is to utilize Michigan City's or Schahfer's trackage (a zero-cost option) and/or sublease railcars to minimize cost whenever possible. Mr. Guerrettaz testified that NIPSCO provided a detailed chart by month that set forth the total railcars and the number of railcars returned.

Mr. Wagner testified NIPSCO's coal demand was substantially lower than forecast and this forced NIPSCO to store unit trains. In addition, Michigan City was placed in a planned maintenance outage for most of the reconciliation period. When Michigan City is in an extended outage and if inventory is above 30 days, NIPSCO typically must park three-unit trains (50% of the fleet) or sub-lease a set if possible. Two unit trains can be held at Michigan City and one is typically stored at a third-party location. NIPSCO did have one set of railcars for Michigan City in long-term storage at a third-party location during the quarter and one set was stored at Michigan City. One of the Michigan City sets was moved into Schahfer service during the reconciliation period for logistics purposes. NIPSCO stored two sets at Schahfer during the reconciliation period. NIPSCO did have two sets in service at Schahfer during most of the reconciliation period to build inventory and to support modest improvements in consumption. Notwithstanding, the railcar market for rotary coal gondolas is volatile and relying on that market to obtain railcars for short-term needs can adversely impact supply reliability and is not prudent.

He stated that the nature of lease agreements and the time required to place cars into service or return cars to lessors is a costly and time-consuming process. Mr. Wagner stated that it is not prudent, practical, or economic to dynamically increase or reduce the fleet size when coal demand deviates from the forecast. Also, the timing of lease terms can preclude fleet size changes since leasing decisions are made on a forward-looking basis. In addition, he noted the determination of fleet size is a multivariate analysis (NIPSCO's system set requirements can vary by two to three sets depending on consumption, railroad performance, and station unloading performance assumptions) and it can take several months to bring cars into the fleet, and it is an even longer process when returning cars. He said there are significant costs to place cars into service including out of route transportation charges, locomotive charges, car mark stenciling costs, inspection costs and other costs. There are costs to return cars to lessors including out of route movements charges, locomotive release charges, shop costs, return maintenance costs, car mark stenciling costs, and other costs.

Mr. Wagner stated he is aware that some large utilities continue to hold "excess" railcars out of concern that it may be difficult and/or more expensive to lease cars if demand improves and that one industry expert indicated that there are essentially no rapid discharge coal railcars available in the market and very few, if any, rotary dump coal gondolas (railcars NIPSCO requires) available. In addition, NIPSCO had a recent discussion with a railcar lessor confirmed that several large utilities are retaining "excess" railcars as they are concerned about potential railcar availability and potential increases in coal unit demand. Overall, the total number of railcars available in the market has decreased substantially over the last few years because scrap rates of coal railcars have been aggressive, and this dynamic has reduced railcar availability and caused lease rates to increase. He stated uncertainty in railcar availability has driven several utilities to hold and store railcars even with decline of coal demand. Therefore, uncertainty in railcar supply and variability in demand requires a conservative approach to fleet management to ensure supply reliability.

In the Commission's April 27, 2011 Order in Cause No. 38706 FAC 90, NIPSCO was ordered, at a minimum, to provide detailed testimony and information regarding: (1) the average spot market price of coal; (2) factors affecting the supply, demand, and cost of coal; (3) any known factors that significantly impact or affect the supply, demand, and cost of coal during the forecast and reconciliation periods; (4) any known factors that significantly impact the delivered cost of coal during the forecast and reconciliation period; and (5) the process NIPSCO utilizes to procure contracted coal supplies. The Commission finds that NIPSCO provided sufficiently detailed testimony and information in this matter to support its forecasted fuel costs. NIPSCO should continue to include in its quarterly FAC filings detailed testimony and information regarding these five factors.

In the Commission's October 21, 2015 Order in Cause No. 38706 FAC 108, NIPSCO was ordered to include in its FAC filings testimony regarding efforts to mitigate costs incurred for unused train sets. The Commission finds NIPSCO provided testimony and information in this proceeding regarding mitigation of storage costs associated with unused train sets, as ordered in Cause No. 38706 FAC 108, and NIPSCO should continue to include in its quarterly FAC filings detailed testimony and information regarding its unused train sets and efforts to mitigate storage related costs.

NIPSCO's estimated and actual fuel costs for the reconciliation period are as follows:

Month	**Actual Fuel Cost $/kWh**	**Estimated Fuel Cost $/kWh**	**Estimating Error: Over (Under)**
October	$0.026694	$0.031380	17.55%
November	$0.040148	$0.032724	(18.49%)
December	$0.046572	$0.035192	(24.44%)
Weighted Average Estimating Error			(12.46%)

Ms. Hook testified the 12.46% difference led to a variance factor of $6.041 primarily driven by (1) NIPSCO's payment to its coal supplier to address the minimum tonnage shortfall, (2) a higher actual cost associated with the MISO Components Cost of Fuel driven by a higher delta LMP component, and (3) a lower actual credit associated with REC Sales for the reconciliation period.

Based on the evidence presented, including Mr. Guerrettaz's testimony upon the reasonableness of NIPSCO's fuel cost and power sales projections, the Commission finds NIPSCO's estimate of its prospective average fuel cost to be recovered during the May, June, and July 2025 billing cycles reasonable.

10. **Return Earned.** Ind. Code §§ 8-1-2-42.3 and 42(d)(3) requires the Commission to find that the FAC applied for will not result in the electric utility earning a return over the return authorized by the Commission in the last proceeding in which the basic rates and charges of the utility were approved. NIPSCO's evidence demonstrates that for the 12 months ending December 31, 2024, NIPSCO earned a jurisdictional return, including transmission, distribution, and storage system improvement charge ("TDSIC") revenues, of $439,151,939. This is $17,045,547 more than NIPSCO's authorized amount of $422,106,392, which includes $406,748,941 approved in the applicable rate cases, plus $15,357,451 of actual TDSIC operating income during the 12 months ended December 31, 2024. NIPSCO calculates the overall earnings bank (sum of the differentials) for the relevant period as negative $126,300,420. Therefore, under Ind. Code § 8-1-2-42.3, NIPSCO did not earn in excess of its authorized net operating income, and no refund is required.

Based on the evidence presented, the Commission finds that for the 12 months ending December 31, 2024, NIPSCO did not earn a return exceeding that authorized in its last base rate case, as appropriately adjusted.

11. **OUCC Report.** Gregory T. Guerrettaz, CPA, President of Financial Solutions Group, Inc testified that the fuel cost element of the proposed fuel cost adjustment has been calculated in conformity with Ind. Code § 8-1-2-42 and previous Commission orders; and the fuel cost adjustment for the quarter ending December 31, 2024 has been properly applied in conformity with the requirements of Cause Nos. 38706 FAC 143 and 144. Mr. Guerrettaz recommended the Commission approve NIPSCO's proposed factor. He also recommended NIPSCO, provide testimony in the next FAC covering the incremental increase in coal prices, the contract amendments (if any), and reasons for and the amount sought for liquidated damages recovery.

Mr. Eckert testified: (1) NIPSCO's treatment of Ancillary Services Market charges follows the treatment the Commission ordered in its June 30, 2009 Phase II Order in Cause No. 43426 ("Phase II Order"); (2) NIPSCO is continuing to recover Day Ahead Revenue Sufficiency Guarantee ("RSG") Distribution Amounts and Real Time RSG First Pass Distribution Amounts through the FAC pursuant to the Phase II Order; (3) NIPSCO's actual monthly cost of fuel (mills/kWh) is comparable to the other large electric investor owned utilities in Indiana; (4) NIPSCO's steam generation costs are higher than the other large electric investor owned utilities in Indiana; (5) NIPSCO should continue to update the Commission on its coal inventory and coal price decrement and if coal decrement pricing is used, NIPSCO should provide justification and documentation supporting the need for and utilization of coal decrement pricing, as well as specify when it expects coal decrement pricing to end and provide inputs to its calculation of the coal price decrement; (6) the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs were reasonable; (7) NIPSCO provided information regarding Jordan Creek, Rosewater, Crossroads Wind, and Crossroads Wind II; and (8) NIPSCO provided an update on the status of the Railroad Litigation.[8] Mr. Eckert sponsored Attachment MDE-3 showing a residential customer using 1,000 kWhs in March 2025 will pay $199.96 (excluding taxes), which consists of $179.72 in base charges set in NIPSCO's last approved rate case (Cause No. 45772), $1.76 in a fuel adjustment clause credit, and $22.00 in non-FAC trackers.

12. **Fuel Cost Adjustment Factor.** Mr. Eckert recommended the Commission approve the proposed fuel cost factor as calculated by Mr. Guerrettaz. Mr. Guerrettaz testified the OUCC is recommending the Commission approve NIPSCO's proposed factor. Based on the evidence, we find NIPSCO has met the tests of Ind. Code § 8-1-2-42(d) for establishing a revised fuel cost adjustment. NIPSCO's evidence presented a variance factor of $0.006041 per kWh to be added to the estimated cost of fuel for bills rendered during the May, June, and July 2025 billing cycles in the amount of $0.034831 per kWh. This results in a fuel cost adjustment factor of $0.001157 per

[8] On September 30, 2019, NIPSCO filed a complaint in the United States District Court for the District of Columbia against the Union Pacific Railroad Company, BNSF Railway Company, CSX Transportation, Inc., and Norfolk Southern Railway Company (currently pending in Civil Action No. 1:19-cv-02927-PLF) for illegally conspiring to use rail fuel surcharges as a mechanism to fix, raise, maintain, and stabilize the prices of rail freight transportation services sold in the United States (the "Railroad Litigation").

kWh, after subtracting the cost of fuel in base rates. A residential customer using 1,000 kWh per month will experience an increase of $2.92 on his or her electric bill from the currently approved factor.

13. <u>2025 Hedging Plan</u>.

A. <u>Background and Relief Requested</u>. In our July 13, 2011 Order in Cause No. 43849 (the "43849 Order"), the Commission directed NIPSCO to file a revised electric hedging plan by May 31 of each year, following the same general methodology used in developing NIPSCO's initial hedging plan ("Initial Hedging Plan") approved in the 43849 Order. The OUCC and the Industrial Group agreed in that proceeding that NIPSCO's proposal regarding the process to file each subsequent electric hedging plan was workable and appropriate to provide the Commission with updated information while also providing stakeholders with an opportunity to comment on the plan to be proposed for the next prospective two-year period. Rosalva Robles, Manager of Planning – Regulatory Support for NIPSCO testified that this process called for NIPSCO to discuss the draft electric hedging plan with the OUCC and the Industrial Group two months before filing Petitioner's hedging plan at the end of May.

Ms. Robles stated that in the September 5, 2012 Order in Cause No. 44205 (the "44205 Order"), the Commission directed NIPSCO to begin filing its annual hedging plans by March 31 instead of May 31. She testified that in the 44205 Order the requirement that NIPSCO discuss the draft hedging plan with its stakeholders at least two months prior to its filing was maintained.

She stated in Cause No. 44205, the Commission expressed in its order a preference to consolidate its annual review of NIPSCO's hedging plans into the FAC process. Ms. Robles stated that on September 30, 2016, in Cause No. 44205 S4, NIPSCO notified the Commission that NIPSCO, the OUCC, and the Industrial Group agreed to schedule and hold a call between December 10th and December 20th of each year to discuss the annual electric hedging plan NIPSCO will propose in its February filing. She stated the interested stakeholders have the opportunity to weigh in on the proposal during the December call and file testimony concerning the proposal in NIPSCO's FAC proceeding, with this schedule providing interested stakeholders approximately nine weeks to consider the proposal before it is included in NIPSCO's February FAC filing and approximately five additional weeks after NIPSCO's February FAC filing to submit testimony.[9]

In this proceeding, NIPSCO requests Commission approval of its updated energy supply plan covering the two-year period July 2025 through June 2027 (the "2025 Hedging Plan").[10]

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[9] Per Ms. Robles, in its Notice, NIPSCO stated that the stakeholders understand that weather events and market forces subsequent to the annual December call could cause NIPSCO to change its annual proposal between the date of the call and the date of its February FAC filing. In that event, NIPSCO will timely inform the stakeholders of the change and offer to discuss the reasons for the change before the plan is included in the February FAC filing.

[10] The Commission approved NIPSCO's 2017 updated energy supply plan covering July 2017 through June 2019 on April 19, 2017 in Cause No. 38706-FAC-114. The Commission approved NIPSCO's 2018 updated energy supply plan covering July 2018 through June 2020 on April 18, 2018 in Cause No. 38706-FAC-118. The Commission approved NIPSCO's 2019 updated energy supply plan covering July 2019 through June 2021 on April 29, 2019 in Cause No. 38706-FAC-122. The Commission approved NIPSCO's 2020 updated energy hedging plan covering July 2020 through June 2022 on April 20, 2020 in Cause No. 38706-FAC-126. The Commission approved NIPSCO's 2021 updated energy hedging plan covering July 2021 through June 2023 (the "2021 Hedging Plan") on April 28, 2021 in

B. **<u>Evidence Presented</u>.** Ms. Robles filed testimony to present and support NIPSCO's 2025 Hedging Plan consistent with the framework and process approved by the Hedging Orders. Ms. Robles testified that NIPSCO met with the OUCC and the Industrial Group via a web meeting on December 2, 2024 to discuss the 2025 Hedging Plan. The 2025 Hedging Plan incorporates stakeholder input received from the meeting.

Ms. Robles explained the objectives of the 2025 Hedging Plan are to reduce the relative movement in the FAC factor from one period to the next and to limit upside price exposure.

Ms. Robles explained that the Initial Hedging Plan assumed that all of the coal-fired generation facilities within the NIPSCO asset portfolio were fixed in price. Coal pricing has historically been less volatile than natural gas pricing and the MISO market price of power, NIPSCO determined that any coal-fired generation used to meet the power supply needs of NIPSCO customers could be classified as a fixed price resource. In addition, renewable projects are also considered and classified as fixed price resources as per NIPSCO's contracted rates with each renewable facility. Ms. Robles stated that any remaining resources that would likely be needed to meet the power supply needs of NIPSCO customers, however, would be classified as floating in price and thus would be considered when developing the hedge plan. She stated the 2025 Hedging Plan also addresses NIPSCO's exposure to both natural gas and electricity price volatility associated with supplying electricity to native load customers.

Ms. Robles explained how the 2025 Hedging Plan is constructed. She stated that NIPSCO determines the monthly volume of MWhs to be hedged by reviewing the total number of on-peak MWhs that would be needed to serve NIPSCO's internal load. The expected number of on-peak MWhs for each month is determined through NIPSCO's demand forecasting process based upon historical usage, estimated economic growth rates, and normalized weather. The PROMOD model is run consistent with the FAC methodology to determine what resources will be used to meet this expected demand, with a special focus on determining the expected number of on-peak MWhs for each calendar month.

Ms. Robles explained that no modifications were made to the existing hedging Plan methodology. NIPSCO developed the 2025 Hedging Plan consistent with the FAC filing methodology, which is intended to better align the Hedging Plan with expected market exposure as presented in NIPSCO's FAC proceedings. The 2025 Hedging Plan (1) assumed forecasted generation based on the ProMod economic model; (2) made no adjustments to the hourly forward-looking power prices; (3) did not remove planned outages in year 2 of the plan for coal units; and (4) sought to achieve an approximate 10-20% hedge on total forecasted MISO purchased power and gas over the Hedging Plan program horizon as reflected in Figure 1. She noted that the plan is only hedging on-peak MISO purchases to achieve an approximate 10%-20% against total forecasted MISO Purchases. This results in higher hedging percentages when only looking at on-peak MISO Purchases.

Cause No. 38706-FAC-130 (the "FAC-130 Order"). The Commission approved NIPSCO's 2022 updated energy supply plan covering the two-year period July 2022 through June 2024 (the "2022 Hedging Plan") on April 27, 2022, in Cause No. 38706-FAC-134 (the "FAC-134 Order"). The Commission approved NIPSCO's 2023 updated energy supply plan covering the two-year period July 2023 through June 2025 (the "2023 Hedging Plan") on April 26, 2023, in Cause No. 38706-FAC-138 (the "FAC-138 Order").

Ms. Robles also explained that NIPSCO developed the 2025 Hedging Plan approach in consideration of its shifting portfolio, which historically was predominantly made up of traditional forms of generation but is transitioning to a portfolio with more renewable generation resources. Using the FAC filing methodology, as discussed above, allows NIPSCO to align the hedge to actual market exposure. This also allows NIPSCO to have a more direct point of comparison to its quarterly FAC filings, allowing for a clearer line to be drawn between the Hedging Plan and the FAC filings. Finally, he noted that maintaining the Hedging Plan off the FAC filings allows NIPSCO to more easily make any adjustments throughout the year as the availability of its generation fleet and deviations in expected load change over time.

Ms. Robles also testified that the proposed target hedging percentages were determined to avoid any stair step growth between the current Hedging Plan and the 2025 Hedging Plan proposed in this proceeding. NIPSCO intends to review this percentage annually with stakeholders, to ensure there is an appropriate level of hedging in place that balances the conflicting goals of ensuring access to low market pricing and shielding customers from market volatility.

Ms. Robles testified NIPSCO followed the 2024 Hedging Plan and NIPSCO expects to follow the updated 2024 Hedging Plan through June 2025. However, if there are any unforeseen, unplanned outages or if there is movement of planned maintenance outages on NIPSCO generating units, NIPSCO may further modify the updated 2024 Hedging Plan, which adjustments are consistent with NIPSCO's past practice of adjusting the hedging plan for material differences in generating unit availability. To the extent NIPSCO updates its Plan further, future FAC filings will disclose any additional deviations from the updated 2024 Hedging Plan.

Ms. Robles testified, consistent with previous plans, the 2025 Hedging Plan is comprised of two types of futures contracts. The first type of futures contract (approved by the 43849 Order) will be used to hedge the on-peak MWhs exposure that relates to Sugar Creek, a combined cycle gas turbine ("CCGT") plant that uses natural gas to generate power. She stated the modeled volumes of power from Sugar Creek are converted to dekatherms by multiplying the number of MWhs for each calendar month by the heat rate of the Sugar Creek plant, which is approximately 7.5 dekatherms per MWh. Once the number of dekatherms per calendar month is determined, this number is divided by 10,000 (the number of dekatherms in each natural gas futures contract) to arrive at the number of natural gas futures contracts to be purchased for each calendar month of delivery. Ms. Robles indicated these contracts settle financially as opposed to physically so they will not have any impact on the physical purchase and delivery of natural gas that is required to run the Sugar Creek plant. She noted that a natural gas futures contract settles financially by comparing the purchase price to the settlement price, netting the difference, and then multiplying this dollar difference by 10,000 to get the dollar amount per contract. Dollars change hands without any physical flow of the commodity itself.

Ms. Robles stated that the second type of futures contract will be to hedge electric price volatility for the MISO power purchases. NIPSCO purchases its power from MISO on a Day Ahead basis at prevailing LMPs. In order to match the electric price volatility exposure with the most closely linked derivative product, NIPSCO will continue to utilize MISO Indiana Hub Day-Ahead Peak Calendar-Month Futures to hedge the MISO power purchases. This type of futures contract also settles financially as opposed to physically so there will be no impact to MISO supply including the dispatch of NIPSCO's generation facilities and NIPSCO's wholesale sales and purchases of electricity. If the fixed price is below the average Day Ahead LMP, NIPSCO will receive payment. If the fixed price is above the average Day Ahead LMP, NIPSCO will make a payment.

Ms. Robles testified the hedges under the 2025 Hedging Plan are being made solely to address native load fuel cost price exposure. She stated that the hedges will not change the economic dispatch of NIPSCO's generation facilities or NIPSCO's wholesale electricity sales and purchases; therefore, NIPSCO continues to propose to pass all hedging gains and seek recovery of prudently incurred hedging losses through its FAC filings.

Ms. Robles explained NIPSCO's proposal for implementing its hedging transactions. She stated that the natural gas futures contracts and the MISO Indiana Hub Day-Ahead Peak Calendar Month Futures contracts will be purchased according to specific schedules and will be purchased on a dollar cost averaging basis up to the second to last month before the month of delivery. She stated that the MISO Indiana Hub Day-Ahead Peak Calendar Month Futures contracts will be purchased on a dollar cost averaging basis up through and including the month prior to the delivery month. She stated the schedule is broken up into the different types of futures contracts to demonstrate when and what number of contracts would be purchased.

Ms. Robles testified NIPSCO intends to purchase the futures contracts on or around the third to last business day of each month to take market timing out of the purchase decision. NIPSCO will, however, take into account market conditions and circumstances known at that time and will use its best judgment in purchasing the futures contracts each month.

Ms. Robles sponsored an analysis to determine the possible impact the 2025 Hedging Plan would have on overall purchased power costs. The analysis shows an example of what additional power supply costs could be incurred if market prices increase by 20% from where market pricing was as of close of business on January 28, 2025. She stated that in the example in Attachment 5-E to Petitioner's Exhibit 5, there could be an additional $28,629,772 of power supply costs (inclusive of CCGT generation and MISO power purchases) if market prices rose by 20% for each month of the planned period. The plan period covers the July 2025 to June 2027 period. The analysis also includes the effect the 2025 Hedging Plan could have on these additional power supply costs. If these hedges were in place and the market was stressed upward by 20% for each month in the plan period, then the additional power supply costs would be $21,237,726 in Attachment 5-E to Petitioner's Exhibit 5, or roughly 74% of what they would be without the hedge plan in place. However, if prices were to move downward by 20%, power supply costs could have been reduced by $28,629,772 in Attachment 5-E to Petitioner's Exhibit 5 through the plan period if no hedge plan had been implemented. The analysis demonstrates how a hedge plan can reduce volatility in power supply costs. While possible savings may be foregone when prices fall, the hedge plan reduces additional costs that may have been incurred when prices rise.

Ms. Robles testified market conditions are dynamic and the analysis is only intended to show the relative impact of the program assuming that market conditions remain the same as they are today. Nevertheless, the analysis provides an indication on what sort of impact this program may have in the future.

Ms. Robles testified NIPSCO has in the past recommended adjustments to its hedging plan approach and continues to evaluate factors that could impact the viability of the currently proposed hedging methodology.

Ms. Robles provided an update on the intra-month hedge for Sugar Creek. She stated that NIPSCO is planning to continue with the practice of converting 30% of the gas contracts expiring at the start of each January, February, and March into power contracts. She explained that NIPSCO's proposal does not alter the current methodology of acquiring gas contracts for Sugar Creek but simply adds a layer of intra-month hedge protection to address historically higher intra-month price volatility in these months.

Ms. Robles testified that during the December 2, 2024 stakeholder meeting, there were no changes discussed or being proposed that would impact this filing, NIPSCO communicated to stakeholders that prior to the filing it would (1) update year 1 and year 2 power percentages as reflected in Attachment 5-F to Petitioner's Exhibit 5, and (2) update pricing and any changes to its maintenance schedule to align with FAC 146. In addition, NIPSCO communicated to stakeholders that as its generation portfolio changes further refinements to the 2025 Hedging Plan may be needed. She also reiterated that NIPSCO will continue to have discussions with its stakeholders around the effectiveness of this plan adjustment and may make additional recommendations in the future, and that NIPSCO appreciates the collaborative nature of discussions with the OUCC and Industrial Group around the overall hedge plan approach.

C. <u>Commission Discussion and Findings</u>. In Cause No. 43849 (the "43849 Order"), the Commission found:

> the mitigation of volatility in fuel procurement is consistent with the provisions of Ind. Code § 8-1-2-42(d), and that implementation of a process to evaluate the risk of fuel price volatility and mitigate such risk through a comprehensive and well-developed hedging plan, is a reasonable step in furtherance of the acquisition of fuel so as to provide electricity to customers at the lowest fuel cost reasonably possible.

The Commission finds NIPSCO's 2025 Hedging Plan is consistent with the approach we approved in the 43849 Order.

Based on the evidence, the Commission finds the proposed 2025 Hedging Plan is reasonable, consistent with the public interest, and should be approved. The evidence demonstrates that NIPSCO communicated with the OUCC and the Industrial Group in the interest of improving the plan consistent with prior Commission Orders, and the Commission finds NIPSCO should continue to do so and continue to consolidate the annual review of NIPSCO's hedging plan into the FAC process.

14. <u>Interim Rates</u>. Because the Commission is unable to determine whether NIPSCO will earn an excess return while this Order is in effect, the Commission finds the rates approved herein should be interim rates, subject to refund.

15. **<u>Major Forced Outages</u>.** Consistent with past Commission Orders, Mr. Saffran sponsored Attachment 4-A to Petitioner's Exhibit 4 describing each major forced outage NIPSCO's generating units experienced during the fourth quarter of 2024, including the length and cause of each major forced outage, the generating unit involved, and proposed solutions to prevent such outages from reoccurring. For purposes of his presentation, a major forced outage is a unit forced outage lasting longer than three consecutive days. He also sponsored Confidential Attachment 4-B providing a root cause analysis for forced outages (if an analysis was completed at the time of the FAC filing).

16. **<u>Status of Railroad Litigation</u>.** In accordance with the Commission's Order in Cause No. 38706 FAC 125, Kelleen M. Krupa, Lead Regulatory Analyst for NiSource Corporate Services Company testified the Railroad Litigation remains pending, and as of December 31, 2024, NIPSCO has deferred $5,571,645.63 in associated legal costs. Mr. Wagner advised the Railroad Litigation remains consolidated for pre-trial purposes in multi-district litigation, where summary judgment briefing and expert witness admissibility briefing concluded in December 2024. On December 19, 2024, all parties filed replies in support of their earlier motions seeking to exclude certain expert opinions offered by the opposing side. On the same date, the defendant railroads also filed replies in support of their summary judgment motions. All parties are now waiting for the judge to issue her decisions in response to the pending motions. NIPSCO's counsel continues to coordinate with the other plaintiff law firms in the multi-district phase of this litigation. The Commission finds NIPSCO provided an update on the status of the Railroad Litigation as ordered in FAC 125 and should continue doing so.

17. **<u>Confidential Information</u>.** On February 18, 2025, NIPSCO filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information in this Cause, which was supported by an affidavit from David Saffran, showing that certain information to be submitted to the Commission was trade secret information as defined in Ind. Code § 24-2-3-2 and should be treated as confidential in accordance with Ind. Code §§ 5-14-3-4 and 8-1-2-29. In a Docket Entry dated March 26, 2025, the Administrative Law Judge found the information should be held confidential on a preliminary basis, after which the information was submitted under seal. After review of the information and consideration of the affidavit, the Commission finds the information is trade secret information as defined in Ind. Code § 24-2-3-2, is exempt from public access and disclosure pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29, and shall be held as confidential and protected from public access and disclosure by the Commission.

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

1. NIPSCO's requested fuel cost adjustment to be applicable to bills rendered during the May, June, and July 2025 billing cycles or until replaced by a fuel cost adjustment approved in a subsequent filing, as set forth in Finding No. 12 above, is approved on an interim basis subject to refund as set out in Finding No. 14 above.

2. Prior to implementing the approved rates, NIPSCO shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division. Such rates shall be effective on or after the Order date subject to Division review and agreement with the amounts reflected.

3. NIPSCO's proposed 2025 Hedging Plan is approved, and NIPSCO shall continue to consult with interested stakeholders in developing future hedging plans.

4. NIPSCO shall continue to include in its quarterly FAC filings updates concerning its utilization of the RECs associated with the wind purchases being recovered through the FAC, as discussed in Finding No. 7C above, and testimony regarding any electric hedging transaction costs and gains/losses for which NIPSCO is seeking recovery through the FAC, as discussed in Finding No. 7D above.

5. NIPSCO shall also continue to include in its quarterly FAC filings the information required by the Commission's April 27, 2011 Order in Cause No. 38706 FAC 90 and testimony regarding efforts to mitigate costs incurred for unused train sets, as discussed in Finding No. 9 above.

6. NIPSCO shall also include in its quarterly FAC filings information related to Day Ahead Marginal Congestion Component and the cost of coal stacks from each supplier to each station for the three actual months on a going forward basis and shall also provide a copy of all new RFPs and contracts for transportation and coal to the extent such are issued.

7. If coal decrement pricing is used or forecast, NIPSCO shall file in its future FAC proceedings appropriate testimony, schedules, and work papers addressing the need for and reasonableness of utilizing coal decrement pricing, as well as when NIPSCO anticipates coal decrement pricing resuming and/or ending, as discussed in Finding No. 7B above.

8. NIPSCO shall prospectively in its quarterly FAC filings explain the reasons for and identify the amount sought for liquidated damages and shall provide all workpapers and other documentation supporting the liquidated damages recovery NIPSCO seeks, consistent with Finding No. 7A above.

9. NIPSCO shall continue to include in its quarterly FAC filings an update on the status of the Railroad Litigation required by the Commission's January 22, 2020 Order in Cause No. 38706 FAC 125, as discussed in Finding No. 16 above.

10. The information filed in this Cause pursuant to NIPSCO's motion for protective order is deemed confidential under Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

11. This Order shall be effective on and after the date of its approval.

<u>BENNETT, FREEMAN, VELETA, AND ZIEGNER CONCUR; HUSTON ABSENT</u>:

APPROVED: APR 30 2025

I hereby certify that the above is a true
and correct copy of the Order as approved.

Dana Kosco Digitally signed by Dana Kosco
Date: 2025.04.30
10:14:46 -04'00'

Dana Kosco
Secretary of the Commission