ORIGINAL

Commissioner	Yes	No	Not Participating
Zay			√
Deig	√		
Swinger	√		
Veleta	√		
Ziegner	√		

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 FOR ELECTRIC SERVICES RENDERED ON OR AFTER MAY 1, 2026, WHICH WILL REMAIN IN PLACE FOR THE PERIOD MAY THROUGH JULY 2026, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 46120, (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, 45472, 45524, 45541, 45887, AND 45908, 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 150** **APPROVED: APR 29 2026**

ORDER OF THE COMMISSION

Presiding Officer:
David E. Ziegner, Commissioner
Sean M. Gorman, Administrative Law Judge

On February 16, 2026, Northern Indiana Public Service Company LLC ("NIPSCO" or "Petitioner") filed with the Indiana Utility Regulatory Commission ("Commission") its Verified Petition in this Cause. NIPSCO concurrently prefiled its case-in-chief which included the direct testimony of NiSource Corporate Services Company employee Kelleen M. Krupa, Lead Regulatory Analyst, and the testimony and exhibits of the following NIPSCO employees:

- Christa P. Hook, Manager of Market Settlements;
- John Wagner, Manager, Fuel Supply;
- David Saffran, Generation Business Systems Administrator in the Operations Management Reporting Division; and
- Rosalva Robles, Manager of Planning – Regulatory Support.

On February 18, 2026, the NIPSCO Industrial Group ("Industrial Group") filed a petition to intervene. This petition was granted on March 4, 2026.[1]

[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.

On March 3, 2026, NIPSCO filed revisions to Mr. Wagner's testimony, and on March 16, 2026, NIPSCO filed revisions to Ms. Krupa's direct testimony and attachments to implement changes related to its Step 2 Compliance Filing in Cause No. 46120.

On March 26, 2026, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled the direct testimony and exhibits of the following:

- Michael D. Eckert, Chief Technical Advisor in the OUCC's Electric Division; and
- Gregory T. Guerrettaz, CPA, President of Financial Solutions Group, Inc.

The Commission held an evidentiary hearing at 1:00 p.m. on April 8, 2026, in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the Industrial Group, by counsel, participated in this evidentiary 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 in this Cause 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 adjustment ("FAC"). 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 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 June 26, 2025 Order in Cause No. 46120 ("46120 Order") (as revised with the implementation of Step 2 rates) was $0.025032 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 2025 averaged $0.032294 per kWh.

4. Requested Fuel Cost Charge. NIPSCO seeks a fuel cost charge of ($0.008552) per kWh for electric services rendered on or after May 1, 2026, which will remain in place until replaced by a fuel cost adjustment approved in a subsequent filing.

The requested fuel cost adjustment includes federal Investment Tax Credits and Production Tax Credits of $8,939,653 and a variance of $8,646,955 that was under-collected during October, November, and December 2025 ("reconciliation period"). NIPSCO's estimated monthly cost of fuel to be recovered in this proceeding for May, June, and July 2026 ("forecast period") is

$14,185,768, and its estimated monthly average sales for that period are 854,871 megawatt hours ("MWhs").[2]

5. Fuel Costs and Operating Expenses. Petitioner's Exhibit 1, Attachment 1-F shows fuel costs for the 12 months ending December 31, 2025, were $55,651,669 above the amount the Commission approved in the 46120 Order. This Attachment also shows NIPSCO's total operating expenses, excluding fuel, for the 12 months ending December 31, 2025, were $133,829,103 above the amounts approved in the 46120 Order. The Commission finds there have been increases in NIPSCO's actual fuel costs for the 12 months ending December 31, 2025, that have not been offset by actual decreases in other operating expenses.

6. Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost. Mr. Wagner 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, 68.9% was coal-fired and 31.1% 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 at the Michigan City Generating Station ("Michigan City"), and Units 17 and 18 at R.M. Schahfer Generating Station ("Schahfer") consuming Illinois Basin ("ILB") coal.

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, combustion and emission characteristics are critical and may eliminate a coal source 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 coal transportation from that source are also critical factors NIPSCO considers.

Mr. Wagner stated NIPSCO had four supply contracts that were effective during the reconciliation period. These contracts were with Peabody COALSALES, LLC ("Peabody") for PRB coal; Core Natural Resources for PRB coal, American Consolidated Natural Resources for NAPP coal; and Peabody for ILB coal. Mr. Wagner confirmed that NIPSCO has no financial interest in the coal producers currently under contract.

Mr. Wagner testified that during the reconciliation period, NIPSCO did not renegotiate and/or amend any of its coal or transportation agreements and that all of NIPSCO's coal supply agreements adjust the price of coal based on a shipment's quality variances from contract specifications. All coal contracts had fixed base prices and did not have market adjustments.

Mr. Wagner testified that producers and customers can be 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

[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 2026 are based on the estimated averages for April, May, and June 2026 as shown on Petitioner's Exhibit 1, Revised Schedule 1.

customer may work together to establish an equitable price adjustment methodology. Mr. Wagner testified 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 testified the cost of coal consumed for NIPSCO for the 12 months ending December 31, 2025, was $69.69 per ton, or $3.435 per million Btu. The cost of coal consumed during the reconciliation period was $61.48 per ton, or $3.061 per million Btu. When compared to the prior reconciliation period, Mr. Wagner stated NIPSCO's delivered cost of coal consumed per ton decreased by $4.26, or $0.224 per million Btu. Mr. Wagner testified the majority of the decrease was due to the reduction in the delivered cost of ILB coal for Schahfer as well as the change in the mix of coal consumed during the reconciliation period when compared to the prior quarter. Specifically, during the reconciliation period, Schahfer consumed 33.5% of tonnage and Michigan City consumed 66.5% of total system tonnage, versus 35.3% and 64.7%, respectively. The cost of ILB coal used at Schahfer is higher than the mix of coal used at Michigan City. PRB and NAPP coal delivered prices increased, which offset some of the cost reduction. Railroad fuel surcharges were modestly lower as well when compared to the reconciliation period and contributed to a portion of the decrease.

Ms. Hook 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.

Based on the evidence presented, the Commission finds NIPSCO's coal and gas procurement decision making and acquisition process has been adequately explained and 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.

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

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 explained when NIPSCO began receiving power and seeking cost recovery associated with the PPAs in accordance with the Commission's Orders in Cause Nos. 45194, 45195, 45310, 45462, 45472, 45524, 45541, 45887, and 45908. She said, in accordance with those Orders, NIPSCO is also crediting any off-system sales ("OSS") created by its wind and solar PPAs. For the reconciliation period, NIPSCO received 324,472 MWhs (October), 365,557 MWhs (November), and 433,557 MWhs (December), as reflected on Petitioner's Exhibit 1, Attachment 1-A, Schedule 5, Pages 1 through 3, Lines 12 through 15. The OSS Adjustment for the forecast period is included in Petitioner's Exhibit 1, Attachment 1-A, Revised Schedule 1, Line 42.

Ms. Hook testified 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 testified that NIPSCO receives RECs associated with the power it purchases from Jordan Creek, Rosewater, Crossroads Wind, Dunn's Bridge I, Green River Solar, Crossroads Solar, Crossroads Wind II, and Appleseed Solar, and Carpenter Wind. She stated that as of this filing, NIPSCO receives RECs associated with the power it generates from Cavalry Solar, Dunns Bridge II Solar, Fairbanks Solar, and Gibson Solar. She explained all RECs are tracked in a renewable energy tracking system. During this FAC period, current vintage RECs were sold with the block size and proceeds from the sales as follows:

Transaction	RECs Sold	Net Proceeds
1	57,668	$ 241,413
2	53,588	$ 286,696
3	40,791	$ 218,232
4	61,469	$ 322,712
5	155,539	$ 816,580
Total	369,055	$ 1,885,632

Ms. Hook testified 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 26 approved solar and wind customers with facilities registered in M-RETS, with nameplate capacities ranging between 0.05 and 2.0 megawatts. Solar and wind generation volumes are uploaded to M-RETS monthly. During this FAC period, Ms. Hook testified one current vintage solar and wind feed-in tariff ("FIT") RECs were sold.

Ms. Hook stated NIPSCO has passed, 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 testified 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 testified 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, 2025.

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, 2025. She testified 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, 2025.

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 by the Commission in its Orders in Cause Nos. 45194, 45195, 45310, 45462, 45472, 45524, 45541, 45887, and 45908 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. <u>Electric Hedging Program</u>. Ms. Hook testified NIPSCO is operating under the Hedging Plan approved in Cause No. 38706 FAC 146 ("Hedging Plan"), and that the following hedging contracts were purchased during the reconciliation period:

Month	**Power Contracts**		**Gas Contracts**	
	Actual	**Var to Plan**	**Actual**	**Var to Plan**
October 2025	20	5	40	5
November 2025	80	75	31	6
December 2025	45	20	27	6

Ms. Hook stated the execution of these contracts is consistent with the Hedging Plan through December 31, 2025. She stated that NIPSCO's 2025 mid/fall year review determined that additional power hedges were not needed for the month of October 2025 and needed for November and December 2025. In addition, the review determined that additional gas hedges were needed for the month of October 2025 but not for November and December 2025. She explained these adjustments are due to the movement of Sugar Creek's 2025 spring planned outage to the fall of 2025. She stated these types of adjustments are consistent with NIPSCO's past practices of adjusting its hedging plan for these differences, but to the extent NIPSCO updates its plan further, future FAC filings will disclose any additional deviations from the approved plan.

Ms. Hook testified that the impact of the hedges entered into for the Hedging Plan during the reconciliation period was a loss of $495,878.80, with a net total impact (including broker and clearing exchange fees) of $509,843.43. Broker fees represented 0.11% of the total value of the transactions occurring during the reconciliation period. She said 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 the 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 stated the hedging profits, losses, and costs are reasonable. He affirmed that NIPSCO entered into 98 gas and 145 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.

7. Midcontinent Independent System Operator ("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 the reconciliation period was $6,406,249.

Ms. Hook testified the Real Time Non-Excessive Energy was $1,450,251 in October 2025 and $1,184,459 in November 2025, which were 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 the actual wind production compared to the forecast. 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 not exceed a cost of $2 million in the reconciliation period.

8. Estimation of Fuel Cost. NIPSCO estimates its total average fuel costs for May, June, and July 2026 will be $14,185,768 monthly. 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 27, 2026, NIPSCO's estimated F.O.B. mine spot market prices for delivery during the forecast period were $15.10 per ton for PRB coal, $49.00 per ton for ILB coal, and $59.00 per ton for NAPP coal. Mr. Wagner testified that market dynamics appear to have kept coal demand somewhat stable globally and coal supply for utility generators in 2025 and into 2026 should be adequate. He stated, given the uncertainty in the energy markets due to delayed coal generation retirements, projected increases in electricity demand due to the emergence of data centers, crypto mining, and other load growth drivers, there could be volatility in energy commodity prices that could impact supply. However, he said there are multiple factors that may impact coal supply and demand during the forecast period including, power prices,

natural gas prices, railroad and coal supplier performance, generating unit performance, weather conditions, and labor disruptions. Notwithstanding, NIPSCO's 2026 purchases are expected to meet forecasted coal delivery requirements and coal producers are obligated to perform under these agreements. He noted that NIPSCO has discussions with its coal suppliers on a regular basis, and suppliers have 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. If demand exceeds the forecast and current supply obligations, Mr. Wagner said NIPSCO may need to purchase additional supply, which may impact fuel costs during the forecast period. The average spot market price during the reconciliation period, when compared to the prior reconciliation period, was $14.97 per ton (up $0.09) for PRB coal, $46.67 per ton (up $1.84) for ILB coal, and $57.67 per ton (up $1.09) for NAPP coal. He stated these are average F.O.B. mine spot market prices only, which do not include the cost of transportation.

In identifying energy market trends and factors affecting the market for coal and transportation during the reconciliation period, Mr. Wagner stated wholesale, day-ahead electricity prices were roughly 28.8% higher during the reconciliation period when compared with the same period in 2024. He said higher energy demand and natural gas pricing helped drive an increase in coal demand compared to the same quarter in 2024. The federal Energy Information Administration ("EIA") projects the U.S. electric energy supply mix for 2025 and 2026 in its latest outlook as follows: (1) Renewable generation (including hydro) provided 24% of the nation's energy mix in 2025 and is expected to provide 25% in 2026 and 27% in 2027; (2) nuclear comprised 18% of electric generation in 2025 and is expected to provide 18% of the mix in 2026 and 2027; (3) natural gas-fired generation provided 40% of the mix in 2025 and is expected to provide 40% in 2026 and 39% in 2027; (4) coal-fired generation provided 17% of the energy in 2025 and is expected to provide 16% of the mix in 2026 and 15% of the mix in 2027; and (5) U.S. coal production increased by 4.0% in 2025 when compared with 2024 levels and is expected to decrease 2.5% in 2026 and 3.6% in 2027.

Mr. Wagner testified that Henry Hub spot pricing is expected to average to $4.31 per million Btu in 2026 and increase to $4.38 per million Btu in 2027. In addition, Illinois Basin spot coal prices are up roughly 15%, PRB spot coal prices are up 7%, and NAPP prices are up 11% when compared to year-ago levels. He said higher natural gas pricing drove an increase in coal demand, and the EIA expects gas pricing to stabilize. Increased natural gas prices also supported coal price increases during the reconciliation period. The EIA also expects utilities will increase coal inventories by the end of 2026 that could offset some the projected consumption in 2026. In addition, several planned U.S. coal generation retirements have been delayed due to the President's Executive Orders issued in April 2025. Notwithstanding, he said near-term uncertainty and higher energy prices may allow coal pricing to increase, but long-term trends should limit price volatility. He also said coal demand will likely decline in the long run, driven by the age of the coal units and/or decreased utilization, stable natural gas prices, and increased renewable production.

Mr. Wagner testified that API 2 prices were roughly 5.8% lower during the reconciliation period compared to the same period in 2024. 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 reached 108.4 million tons in 2024 (a five-year high); however, global coal demand has softened during 2025, and exports fell to 94.2 million tons but are expected to recover

to 100.2 million tons in 2026. Mr. Wagner stated that, overall, the outlook for global coal use is somewhat stable and export opportunities are expected to remain steady. The EIA projections assume gross domestic product grew by 2.2% in 2025 and should grow 2.4% in 2026 and 2.0% in 2027.

Mr. Wagner testified that for transportation, railroad performance continues to trend better than historical norms and has been consistent but that reduced investment in coal production and coal transportation capacity, 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 coal supplier and railroad performance.

Mr. Wagner testified that NIPSCO's estimate for the cost of coal consumed for generation in the forecast period is $50.98 per ton or $2.673 per million Btu. He testified 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 pricing ("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 testified that the fuel supply group also provides a forecast of beginning inventory values in dollars and quantities in tons for each generating station, which 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 9, 2026, using its production cost modeling system, PROMOD, and made reasonable decisions under the circumstances known at that point in time.[3]

NIPSCO's fuel cost is forecasted to be $16.594 compared to a base cost of fuel of $25.032. Ms. Hook explained that in comparing this FAC to its prior FAC: (1) the combined cycle unit is projected to be lower on a total MWh basis and cost, (2) solar generation is projected to increase in total MWh, (3) wind energy purchases and wind joint venture purchases are projected to be lower on a total MWh basis and cost, and (4) the OSS Adjustment is projected to increase in total MWh with a forecasted credit projected to be greater.

Ms. Hook stated that to ensure NIPSCO provides electricity to its retail customers at the lowest fuel cost reasonably possible, NIPSCO has utilized the approved Hedging Plan and will continue to do so 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.

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

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

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 February 9, 2026, was $3.688 per gallon (a 0.60% year-over-year increase). The EIA expects strong global demand for oil but downward pressure on oil prices, as production is expected to outpace demand. Given these assumptions, the EIA expects HDF prices to decline modestly over the next two years and forecasts diesel prices will average $3.427 per gallon during 2026 and increase to $3.466 in 2027. 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. He said all anticipated coal supply requirements for 2026 should be met under current coal supply and transportation agreements. Coal market demand has rebounded over the last year, and the coal supply chain is meeting the demand increase. However, if coal demand increases further, utilities may struggle to schedule deliveries as railroads and coal producers have rationalized assets, labor, and production, and it may take time for production and shipments to rise to meet any rapid 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 coal inventory supply at Schahfer was approximately 4 days (down 12 days from the prior quarter) at the end of the reconciliation period. He testified Michigan City's PRB coal inventory was 22 days and the NAPP inventory was at 32 days at the end of the reconciliation period.

Mr. Wagner testified NIPSCO's fleet size was 641 railcars (five 125-car sets with 2.6% spares) at the end of the reconciliation period. The typical spare railcar pool ranges between 2% and 8%. According to Mr. Wagner, NIPSCO utilized 78% of the fleet during the reconciliation period. He noted storage requirements varied during the reconciliation period as coal consumption fluctuated due to planned and forced unit outages and to control inventory ahead of Schahfer's planned retirement at the end of 2025. Consumption continues to trend below historical rates driven by periods of economic reserve (idle coal units) due to volatile and softening energy market conditions during the period, renewable production, much better than expected railroad performance, and planned and unplanned station maintenance outages. Coal unit consumption was 41% of the system's maximum coal demand rate during the reconciliation period and railcar utilization exceeded the station generation utilization rates. Mr. Wagner stated that NIPSCO frequently evaluates its railcar needs and considers demand/delivery requirements (forecasted, historical, and actual), railroad performance, station unloading performance, and the timing of lease expirations. Additionally, NIPSCO will continue to use commercially reasonable efforts to manage its railcar fleet to ensure economic, and reliable coal deliveries.

Mr. Wagner testified that NIPSCO's fleet size was reduced by one set in 2024 to lower cost while balancing reliability. NIPSCO also minimized storage costs during the reconciliation

period by storing one to two unit trains at Schahfer at no cost and storing only one set of Michigan City's railcars at a third party storage during the latter half of the reconciliation period. He stated that the availability of coal gondolas is extremely limited and relying on that market to obtain railcars for short-term needs can adversely impact supply reliability and is not prudent. In addition, the timing of lease terms can preclude fleet size changes as leasing decisions are made on a forward-looking basis. He noted the determination of fleet size is a multivariate analysis and it can take several months to bring cars into the fleet, and it is an even longer process when returning cars. In addition, he stated that moving rail cars in and out of service is a costly process. Therefore, the forward-looking nature of lease agreements and the time and costs required to place cars in and out of service make it difficult to make short-term changes to the size of the fleet and it is not prudent, practical, nor economic to dynamically change the fleet size when coal demand deviates from the forecast. In addition, railcars provide deliverability and can be invaluable if demand increases and/or railroad performance degrades.

Mr. Wagner stated NIPSCO also consults with industry experts and 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. Through discussions with industry experts, Mr. Wagner is aware that the market for coal cars is tight and lease rates have increased dramatically. He said that one industry expert expects that utilities may need to build railcars as the age of the fleet approaches end of life and as coal railcars continue to attrite. Therefore, NIPSCO's fleet must have sufficient capacity to react to increases in demand or decreases in railroad performance without depending on the market for railcars. For reference, NIPSCO's fleet size at the end of the reconciliation period can provide 76% of NIPSCO's maximum coal unit demand and at average railroad cycle times. He said that given the tight supply of railcars in the market and the uncertainty in demand and railroad performance, NIPSCO has taken 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 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	$0.026652	$0.023508	(11.80%)
November	$0.036634	$0.034055	(7.04%)
December	$0.034052	$0.033696	(1.05%)
Weighted Average Estimating Error			(5.95%)

Ms. Hook testified the 5.95% difference led to a variance factor of $3.372, primarily driven by: (1) higher actual costs associated with steam generation driven by increased dispatch of actual generation by MISO than forecasted, (2) higher actual costs associated with purchases through MISO driven by higher than anticipated market prices ($42.44/MWh actual LMP compared to $38.51/MWh estimated LMP), and (3) higher actual generation and costs associated with wind and solar energy purchases during 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 2026 billing cycles is reasonable.

9. Return Earned. Ind. Code § 8-1-2-42.3 and Ind. Code § 8-1-2-42(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, 2025, NIPSCO earned a jurisdictional return, including TDSIC revenues, of $499,792,967. This is $53,412,702 less than NIPSCO's authorized amount of $553,205,669, which includes $518,342,942 approved in the applicable base rate case, plus $34,862,727 of actual TDSIC and GCT operating income during the 12 months ended December 31, 2025. NIPSCO calculates the overall earnings bank (sum of the differentials) for the relevant period as $194,143,937; 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 ended December 31, 2025, NIPSCO did not earn a return exceeding that authorized in its last base rate case, as appropriately adjusted.

10. OUCC Report. Mr. Guerrettaz testified 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, 2025 has been properly applied in conformity with the requirements of Cause Nos. 38706 FAC 147 and 148. Mr. Guerrettaz testified that the OUCC does not oppose NIPSCO's proposed factor.

Mr. Eckert testified that: (1) NIPSCO's testimony and workpapers accurately reflect the methodology approved in the Commission's Cause No. 43526 Order regarding purchased power over the benchmark; (2) 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"); (3) 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; (4) NIPSCO's actual monthly cost of fuel (mills/kWh) is higher than the other large electric investor owned utilities in Indiana; (5) NIPSCO's steam generation costs are higher than the other large electric investor owned utilities in Indiana; (6) 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; (7) the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs were reasonable; (8) NIPSCO provided information regarding Jordan Creek, Rosewater, Crossroads Wind, Dunn's Bridge I, Crossroads Solar, Crossroads Wind II, Green River Solar, Appleseed Solar, and Carpenter Wind; (9) NIPSCO provided an update on the status of the Railroad Litigation,[4] and (10) NIPSCO's forecasted off system sales is accurate.

11. Fuel Cost Adjustment Factor. Based on the evidence, the Commission finds 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 $0.003372 per to be added to the estimated cost of fuel for electric services rendered on or after May 1, 2026, which will remain in place until replaced by a fuel cost adjustment approved in a subsequent filing in the amount of $0.016480 per kWh. This results in a fuel cost adjustment factor of ($0.008552) per kWh, after subtracting the cost of fuel in base rates. A residential customer using 1,000 kWh per month will experience a decrease of $2.85 on his or her electric bill from the currently approved factor.

12. 2026 Hedging Plan.

A. Background and Relief Requested. In our July 13, 2011 Order in Cause No. 43849 ("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 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 an opportunity to comment on the plan to be proposed for the next prospective two-year period. Ms. Robles testified 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 Commission directed NIPSCO to begin filing its annual hedging plans by March 31 instead of May 31. However, the requirement that NIPSCO discuss the draft hedging plan with its stakeholders at least two months prior to its filing was maintained.

Ms. Robles stated the Commission, in its Order in Cause No. 44205 S4, expressed a preference to consolidate its annual review of NIPSCO's hedging plans into the FAC process. Ms.

[4] 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) alleging these railroads illegally conspired 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").

Robles stated that on September 30, 2016, NIPSCO notified the Commission that NIPSCO, the OUCC, and the Industrial Group agreed to schedule and hold a call between December 10 and December 20 each year to discuss the annual electric hedging plan NIPSCO would 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.

In this proceeding, NIPSCO requests Commission approval of its updated energy supply plan covering the two-year period July 2026 through June 2028 ("2026 Hedging Plan").

B. <u>Evidence Presented</u>. Ms. Robles testified that NIPSCO met with the OUCC and the Industrial Group via a web meeting on December 10, 2025, to discuss the 2026 Hedging Plan. The 2026 Hedging Plan incorporates stakeholder input received from the meeting.

Ms. Robles explained the objectives of the 2026 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 NIPSCO's initial hedging plan assumed that all of the coal-fired generation facilities within the NIPSCO asset portfolio were fixed in price because coal pricing has historically been less volatile than natural gas pricing and the MISO market price of power. 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.

Ms. Robles stated the 2026 Hedging Plan addresses NIPSCO's exposure to both natural gas and electricity price volatility associated with supplying electricity to native load customers. She explained how the 2026 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 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. Instead, NIPSCO developed the 2026 Hedging Plan consistent with the FAC filing methodology, which is intended to better align it with expected market exposure as presented in NIPSCO's FAC proceedings. The 2026 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 2026 Hedging Plan program horizon. She noted that the 2026 Hedging Plan is only hedging

on-peak MISO purchases to achieve an approximate 10%-20% against total forecasted MISO purchases, which results in higher hedging percentages.

Ms. Robles also explained that NIPSCO developed the 2026 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. She said that the FAC filing methodology allows NIPSCO to align the hedge to actual market exposure. It 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 2026 Hedging Plan and the FAC filings. Finally, she noted that maintaining the 2026 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 2026 Hedging Plan. 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 its current Hedging Plan and expects to continue following it through June 2026; 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 its Hedging Plan, which adjustments are consistent with NIPSCO's past practice of adjusting for material differences in generating unit availability. To the extent NIPSCO updates its Hedging Plan further, future FAC filings will disclose any additional deviations.

Ms. Robles testified, consistent with previous plans, the 2026 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 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 7.0 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 testified 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 its wholesale sales and purchases of electricity. If the fixed price is below the average Day Ahead LMP, NIPSCO will receive payment; conversely, if the fixed price is above the average Day Ahead LMP, NIPSCO will make a payment.

Ms. Robles testified the hedges under the 2026 Hedging Plan are being made solely to address native load fuel cost price exposure. She testified that the hedges will not change the economic dispatch of NIPSCO's generation facilities or its 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 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, consider market conditions and circumstances known at that time and use its best judgment in purchasing the futures contracts each month.

Ms. Robles sponsored an analysis to determine the possible impact the 2026 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 26, 2026. In the example, there could be an additional $27,091,721 of power supply costs (inclusive of combined cycle gas turbine generation and MISO power purchases) if market prices rose by 20% for each month of the planned period, which covers July 2026 to June 2028. The analysis also includes the effect the 2026 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 $20,168,366, 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 $27,091,721 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 that 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. She further testified that 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 10, 2025 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 Petitioner's Exhibit 5, Attachment 5-F, and (2) update pricing and any changes to its maintenance schedule to align with this FAC. In addition, NIPSCO communicated to stakeholders that as NIPSCO's generation portfolio changes further refinements to the 2026 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. Commission Discussion and Findings. In Cause No. 43849, 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.

43849 Order at 10. The Commission finds NIPSCO's 2026 Hedging Plan is consistent with the approach we approved in the 43849 Order.

Based on the evidence, the Commission finds the proposed 2026 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 its plan consistent with prior Commission Orders. Neither the OUCC nor the Industrial Group opposed the 2026 Hedging Plan. The Commission further finds that NIPSCO should continue to communicate with the OUCC and the Industrial Group regarding its hedging program and consolidate the annual review of its hedging plan into the FAC process.

13. Interim Rates. 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.

14. Major Forced Outages. Consistent with past Commission Orders, Mr. Saffran sponsored Petitioner's Exhibit 4, Attachment 4-A describing each major forced outage NIPSCO's generating units experienced during the fourth quarter of 2025, 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 of Petitioner's Exhibit 4-C providing root cause analysis reports for forced outages that were complete at the time of the FAC filing.

15. Status of Railroad Litigation. In accordance with the Commission's Order in Cause No. 38706 FAC 125, Ms. Krupa testified that as of December 31, 2025, NIPSCO has deferred $5,731,708.52 in legal costs associated with the Railroad Litigation. Mr. Wagner advised that NIPSCO's case remains on appeal at the U.S. Circuit Court of Appeals for the District of Columbia Circuit, where it is consolidated with other similar appeals. NIPSCO and other plaintiffs from the lower court are appealing the summary judgment decision issued in the U.S. District Court for the District of Columbia on June 24, 2025. On November 12, 2025, the Circuit Court of Appeals issued a procedural schedule for the consolidated appeal. Pursuant to this schedule, NIPSCO and other appellants jointly filed an Appellants' Opening Brief on December 12, 2025. Several amicus briefs were filed December 19, 2025, and the appellee railroads are scheduled to file their Respondents' Brief on February 26, 2026. NIPSCO's counsel continues to coordinate with the law firms for the other appellant parties in effecting the appeal. The Commission finds NIPSCO provided an update on the status of the Railroad Litigation and should continue doing so in its FAC proceedings.

16. Confidential Information. On February 16, 2026, NIPSCO filed a motion for protective order that was supported by an affidavit showing documents to be submitted to the Commission contain trade secrets as defined by Ind. Code § 24-2-3-2 and should be held confidential in accordance with Ind. Code §§ 8-1-2-29 and 5-14-3-4. In a March 4, 2026 docket entry, such information was found to preliminarily be confidential, after which NIPSCO submitted the information under seal. The Commission finds such information is confidential under Ind. Code § 5-14-3-4, is exempt from public access and disclosure by Indiana law, and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

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

1. NIPSCO's requested fuel cost adjustment to be applicable for electric services rendered on or after May 1, 2026, which will remain in place until replaced by a fuel cost adjustment approved in a subsequent filing, as set forth in Finding No. 11 above, is approved on an interim basis subject to refund as set out in Finding No. 13 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 2026 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

and testimony regarding any electric hedging transaction costs and gains/losses for which NIPSCO is seeking recovery through the FAC.

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.

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 request for proposals and contracts for transportation and coal to the extent such new requests for proposals and/or contracts are issued.

7. If coal decrement pricing is used or forecast, NIPSCO shall include in its future FAC proceedings appropriate testimony, schedules, and workpapers addressing the need for and reasonableness of utilizing coal decrement pricing, as well as when NIPSCO anticipates coal decrement pricing resuming and/or ending.

8. NIPSCO shall continue to include in its quarterly FAC filings an update on the status of the Railroad Litigation.

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

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

DEIG, SWINGER, VELETA, AND ZIEGNER CONCUR; ZAY ABSENT:

APPROVED: APR 29 2026

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: 2026.04.29 10:21:36 -04'00'

Dana Kosco
Secretary of the Commission