ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
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 DURING THE BILLING CYCLES OF MAY, JUNE, AND JULY 2023, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 45159, (2) RATEMAKING TREATMENT FOR THE COSTS INCURRED UNDER WHOLESALE PURCHASE AND SALE AGREEMENTS FOR WIND ENERGY APPROVED IN CAUSE NOS. 43393, 45194, 45195, AND 45310, 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 138** **APPROVED: APR 26 2023**

ORDER OF THE COMMISSION

Presiding Officer:
Carol Sparks Drake, Senior Administrative Law Judge

On February 17, 2023, Northern Indiana Public Service Company LLC ("NIPSCO" or "Petitioner") filed a Verified Petition in this Cause seeking approval from the Indiana Utility Regulatory Commission ("Commission") of: (1) a fuel cost adjustment to be applicable during the May, June, and July 2023 billing cycles or until replaced by a fuel cost adjustment approved in a subsequent filing, pursuant to Ind. Code § 8-1-2-42 and Cause No. 45159; (2) ratemaking treatment for the costs incurred under wholesale purchase and sale agreements for wind energy approved in Cause Nos. 43393, 45194, 45195, and 45310; and (3) an updated hedging plan, including recovery of certain costs associated with that plan. NIPSCO concurrently prefiled its case-in-chief which included the direct testimony of NiSource Corporate Services Company employee Kelleen M. Krupa, a Lead Regulatory Analyst, and the testimony and exhibits of the following NIPSCO employees:

- Rosalva Robles, Manager of Planning – Regulatory Support
- John A. Wagner, Manager, Fuel Supply
- David Saffran, Generation Business Systems Administrator in the Operations Management Reporting Division
- Andrew S. Campbell, Director of Portfolio Planning and Origination.

On February 17, 2023, NIPSCO also filed a motion requesting confidential treatment for certain information ("Confidential Information"). In a docket entry issued on March 1, 2023, the requested confidential treatment was granted on a preliminary basis.

On February 21, 2023, the NIPSCO Industrial Group ("Industrial Group") filed a petition to intervene. This petition was granted on March 1, 2023.[1]

On March 22, 2023, NIPSCO filed supplemental direct testimony for Ms. Krupa, along with revised schedules, because NIPSCO's projected May through July 2023 fuel cost charges decreased significantly after NIPSCO completed its forecast on February 9, 2023. NIPSCO 's supplemental filing supports a revised FAC factor that reduces the originally requested factor.

The Indiana Office of Utility Consumer Counselor ("OUCC") on March 24, 2023, prefiled the direct testimony and exhibits of the following:

- Michael D. Eckert, Director of the OUCC's Electric Division
- Gregory T. Guerrettaz, CPA and President of Financial Solutions Group, Inc.

NIPSCO did not file rebuttal testimony.

The Commission noticed this matter for an evidentiary hearing at 9:30 a.m. on April 6, 2023, in Hearing Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the Industrial Group, by counsel, participated in this hearing, and the testimony and exhibits of NIPSCO and the OUCC were admitted without objection.

Based upon 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 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 December 4, 2019 Order in Cause No. 45159 ("45159 Order") was $0.026736 per kilowatt hour ("kWh"). NIPSCO's cost of fuel to generate

[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.

electricity and the cost of fuel included in the cost of purchased electricity for the months of October, November, and December 2022 averaged $0.043314 per kWh.

4. Requested Fuel Cost Charge. NIPSCO seeks to change its fuel cost adjustment from the current fuel cost charge of $0.034284 per kWh for bills rendered during the February through April 2023 billing cycles to a fuel cost charge of $0.004477 per kWh for bills rendered during the May through July 2023 billing cycles or until replaced by a different fuel cost adjustment approved in a subsequent filing. The OUCC concurred with NIPSCO's proposed revised factor, per Mr. Guerrettaz, for the May, June, and July 2023 billing cycles.

The requested fuel cost adjustment includes a variance of $6,276,382 that was over-collected during October through December 2022 ("reconciliation period"), a reduction of $1,343,800 from the earnings test, and a reduction of $312,444 representing the amount remaining after payment of the approved attorney fees and expenses in compliance with the December 14, 2022 Order in Cause No. 38706 FAC 130 S2. NIPSCO's estimated monthly average cost of fuel to be recovered in this proceeding for the forecasted billing period of May through July 2023 is $29,033,187, and its estimated monthly average sales for that period are 845,434 MWhs.

5. Statutory Requirements. Ind. Code § 8-1-2-42(d) states 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] of this chapter, if the fuel charge applied for will result in the electric utility earning 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 (3) calendar months are reasonable after taking into consideration:
>
>> (A) the actual fuel costs experienced by the utility during the latest three (3) calendar months for which actual fuel costs are available; and
>>
>> (B) the estimated fuel costs for the same latest three (3) 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, 2022, were $272,044,967 above the amount the Commission approved in the 45159 Order. NIPSCO's Attachment 1-F also shows Petitioner's total operating expenses, excluding fuel, for the 12 months ending December 31, 2022, were $8,574,989 above the amount approved in the 45159 Order. The Commission finds there have been increases in NIPSCO's actual fuel costs for the 12 months ending December 31, 2022, 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. Mr. Wagner testified that NIPSCO made every reasonable effort to acquire fuel 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 37.3% of the energy generated, and 62.7% of the energy generated was gas-fired. He stated NIPSCO's coal-fired generation consumes coal from various supply regions, with the Michigan City Generating Station ("Michigan City") consuming a mix of Powder River Basin ("PRB") and Northern Appalachian ("NAPP") coal, and Units 17 and 18 at the 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 emissions 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, drastically increase the total cost of generation (fuel and operational costs) or inhibit NIPSCO's 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 purchased coal during the reconciliation period under four supply contracts. These contracts were with Arch Coal Sales Company for PRB coal; American Consolidated Natural Resources for NAPP coal; Columbia Resource Group, Inc. for test coal, and Peabody COALSALES, LLC for ILB coal. Mr. Wagner confirmed NIPSCO has no financial interest in the coal producers currently under contract.

Mr. Wagner testified producers and customers are reluctant to execute long-term contracts with fixed prices without some 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 the guaranteed quality specifications. Mr. Wagner testified one of NIPSCO's term coal contracts in effect during the reconciliation period had mostly fixed prices specified in the contract, with a portion of the volume under this contract priced using a coal market index. Another contract had rates that are indexed to generating unit hourly Day-Ahead Locational

Marginal Power Prices ("LMPs"). Additionally, under NIPSCO's coal supply agreements, the price of coal is adjusted based on a shipment's quality variances from contract specifications.

Mr. Wagner testified the delivered cost of coal consumed by NIPSCO's generating stations for the 12 months ending December 31, 2022, was $66.09 per ton or $3.234 per million BTU. The cost of coal consumed during the reconciliation period was $85.74 per ton or $4.005 per million BTU. The delivered cost of coal consumed during the prior reconciliation period was $68.86 per ton or $3.387 per million BTU. When compared to the prior reconciliation period, NIPSCO's delivered cost of coal consumed per ton increased $16.88, and the cost was up $0.618 on a per million BTU basis. Mr. Wagner stated several factors contributed to the change in the system cost of coal expensed during the reconciliation period, including an increase in the consumption of ILB coal relative to PRB coal consumption. He advised the PRB coal used at Michigan City is lower cost than the ILB coal used at Schahfer, and this difference in mix contributed to the higher unit cost. Other contributing factors included increases in ILB delivered coal expense, largely due to higher coal prices and higher transportation rates that are indexed to station power prices, offset by modest decreases in railroad fuel surcharges.

Mr. Guerrettaz testified some components of coal costs include the base coal cost, dust treatment, freeze treatment, and miscellaneous projected coal quality costs. He stated transportation cost components include the base transportation costs, any fuel adjustments, pricing adjustments, incremental costs associated with operations, maintenance, and lease of railcars, and index pricing. Mr. Guerrettaz testified that due to the potentially large impact of index pricing, it is important to determine the resulting impact on delivery prices. He advised that during the OUCC's audit, NIPSCO broke down the coal cost components by unit, showing transportation, cost of coal, and other coal cost elements separately, and he confirmed the OUCC requests this breakdown in each FAC. Mr. Guerrettaz also advised that NIPSCO purchased additional coal this FAC reconciliation period from a current supplier at a higher market price than in the recent past. As a result of this purchase, he stated NIPSCO's cost per MMBTU was the highest ever for Schafer Units 17 and 18 and well exceeded the average cost per MMBTU for December 2022 by as much as $1.67 per MMBTU. Additionally, Mr. Guerrettaz stated NIPSCO's spot coal purchase in the last FAC proceeding increased the cost of fuel such that if December 2022 had not been so cold, the units would not have been economical.

Ms. Robles testified Petitioner made every reasonable effort to purchase natural gas so as to provide electricity to its customers at the lowest reasonable price, and there have been no changes to NIPSCO's gas purchasing practices for NIPSCO's generation located on or located off NIPSCO's gas distribution system (Sugar Creek Generating Station) during the reconciliation or forecast period.

Based on the evidence presented, the Commission finds NIPSCO has adequately explained its coal and gas procurement decision making, and its acquisition process is reasonable.

B. Coal Decrement Pricing. Mr. Wagner testified NIPSCO does not anticipate utilizing decrement pricing but will continue to update the Commission about decrement pricing in its future FAC filings.

OUCC witness Eckert asked 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.

Based on the evidence, the Commission finds decrement pricing is not included in NIPSCO's forecast for purposes of this FAC proceeding. If in the future coal decrement pricing is included in NIPSCO's forecast or has been used, NIPSCO shall file testimony, schedules, and workpapers addressing the need for and reasonableness of such decrement pricing and related inputs consistent with the Commission's July 17, 2019, Order in Cause No. 38706 FAC 123.

C. Renewable Energy Credits ("RECs"). Ms. Robles 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 July 24, 2008, Order in Cause No. 43393 ("43393 Order"), NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreements for wind energy from Barton Windpower LLC ("Barton") on April 10, 2009, and from Buffalo Ridge I LLC ("Buffalo Ridge") on April 15, 2009. Consistent with the Commission's August 7, 2019, Order in Cause No. 45194 ("45194 Order"), NIPSCO began receiving power and seeking recovery of such costs for wind energy from Rosewater Wind Generation LLC ("Rosewater") on November 20, 2020, and per the Order in Cause No. 45195 ("45195 Order") from Jordan Creek Wind Farm LLC ("Jordan Creek") on December 2, 2020. Pursuant to the 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 ("Indiana Crossroads") on December 17, 2021. Under the 43393, 45194, 45195, and 45310 Orders, NIPSCO is also crediting any off-system sales created by its wind PPAs with Barton, Buffalo Ridge, and Jordan Creek. She stated the wind PPA adjustment for April, May, and June 2023 (the "forecast period") is based on the average of the actual wind PPA adjustments incurred for the 12 months ended December 31, 2022. For the reconciliation period of October, November, and December 2022, NIPSCO received 245,184 MWhs, 308,666 MWhs, and 270,044 MWhs, respectively.

Additionally, Ms. Robles testified that pursuant to the Commission's May 5, 2021 Order in Cause No. 45462, NIPSCO expects to begin receiving power and seeking to recover costs associated with the wholesale purchase and sale agreement for solar energy from Dunn's Bridge I Solar Generation LLC ("Dunn's Bridge I") in June 2023, and pursuant to the Commission's July 28, 2021 Order in Cause No. 45524, NIPSCO expects to begin receiving power and seeking to recover costs associated with the wholesale purchase and sale agreement for solar energy from Indiana Crossroads Solar Generation LLC ("Crossroads Solar") in April 2023; therefore, the costs associated with the wholesale purchase and sale agreements for solar energy with Crossroads Solar and Dunn's Bridge I are included in NIPSCO's projected fuel costs.

Ms. Robles testified each megawatt hour of power generated from a qualified resource can be awarded a REC. Since no national standard currently exists, she stated each jurisdiction has its own regulations upon how to qualify and account for RECs. Ms. Robles testified that as of this FAC filing, NIPSCO receives RECs associated with the power it purchases from Barton, Buffalo Ridge, Jordan Creek, Rosewater, and Indiana Crossroads. All RECs are or will be tracked in a renewable energy tracking system. Because NIPSCO's solar projects have not yet reached commercial operation, Ms. Robles stated NIPSCO has not received RECs for these projects but will begin receiving RECs following commercial operation. Ms. Robles testified it is anticipated these RECs will be handled similar to RECs from wind projects.

During this FAC period, Ms. Robles stated current vintage RECs were sold. The block sizes and proceeds from the sales were:

Transaction	RECs Sold	Net Proceeds
1	150,000	$ 443,250
2	50,000	$ 147,750
3	25,000	$ 73,875
4	50,000	$ 147,750
5	50,000	$ 184,688
6	50,000	$ 257,500
7	50,000	$ 262,500
8	10,000	$ 34,475
Total	435,000	$ 1,551,788

Also, during this reconciliation period, she stated Petitioner transferred RECs to the Green Power Rider ("GPR") program. Specifically, a block of 116,706 RECs was transferred to the GPR program with net proceeds of $263,603.

Ms. Robles 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 Midcontinent Independent System Operator, Inc. ("MISO") line item. She noted REC prices are increasing, resulting in increasing revenues from REC sales being passed back to NIPSCO's customers. Per Ms. Robles, NIPSCO continually monitors and evaluates the marketability for all RECs, and as the possibility for future legislation evolves, NIPSCO will make appropriate changes its REC strategy.

Ms. Robles stated NIPSCO now has 25 approved solar and wind feed-in tariff ("FIT") customers with facilities registered in the Midwest Renewable Energy Tracking System ("M-RETS"),[2] 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, a block of 23,332 current vintage solar and wind FIT RECs were sold with net proceeds of $40,831. Also, NIPSCO transferred 27 FIT RECs to the GPR program with net proceeds of $68. Ms. Robles stated NIPSCO has passed and anticipates continuing to pass the proceeds from FIT RECs sales back to customers through the Purchased Power other than MISO line item. She noted NIPSCO continues to discuss with brokers and market participants the best means of marketing the FIT RECs.

Mr. Guerrettaz testified that NIPSCO provided a net credit of $1,851,801 to its customers from the sale of RECs for this FAC.

[2] M-RETS is a web-based system used by power generators, utilities, marketers, and qualified reporting entities in participating states and provinces.

Ms. Robles testified NIPSCO does not expect to buy firm, long-term purchased power during the forecast period and did not enter into any third-party energy transactions for physical power that impacted the reconciliation period. She stated NIPSCO will, however, continue to consider entering into short-term third-party agreements to protect its customers from market influences.

Ms. Robles testified NIPSCO incorporated forecasted FIT purchases in this filing. She explained that NIPSCO projects FIT purchases for the forecast period based on the average of actual FIT purchases incurred for the 12 months ending December 31, 2022. NIPSCO also incorporated forecasted known fixed transportation reservation charges and a related credit associated with Sugar Creek. Additionally, Ms. Robles advised that NIPSCO completed its forecast for this FAC filing on February 9, 2023, using its production cost modeling system, PROMOD, and made reasonable decisions under the circumstances known at that time. Ms. Robles noted forward market pricing has shown decreases for both natural gas and power pricing, falling by approximately 20-25% from when NIPSCO originally prepared its forecast in mid-January to its updated February 9, 2023, forecast. In her supplemental testimony, Ms. Krupa testified that forecasted gas and energy market prices have further decreased, prompting NIPSCO to reduce the fuel cost adjustment originally requested. She stated NIPSCO's projected fuel cost charge for the FAC period decreased from \$0.005930/kWh to \$0.004477/kWh due to changing gas market conditions and resulting changes in NIPSCO's forecasts. Ms. Krupa testified the revised proposed FAC factor is \$0.001453 less than the factor initially filed on February 17, 2023, representing a reduction of about 25%.

The Commission finds NIPSCO shall continue to include in its quarterly FAC filings updates concerning its utilization of RECs associated with wind purchases being recovered through the authority granted in the 43393, 45194, 45195, and 45310 Orders and any other future renewable purchases.

D. <u>Electric Hedging Program</u>. Per Ms. Robles, the table below shows the hedging contracts purchased during the reconciliation period.

Month	Power Contacts		Gas Contracts	
	Actual	Var to Plan	Actual	Var to Plan
October 2022	45	10	35	0
November 2022	5	10	37	0
December 2022	0	25	36	6

Ms. Robles stated the execution of these contracts was consistent with NIPSCO's approved electric hedging plan through December 2022. She stated NIPSCO is operating under the updated 2022-2024 Hedging Plan that began in July 2022.

Ms. Robles testified the impact of the hedges during the reconciliation period was a loss of \$204,654. The net total impact of the hedging plan in this FAC reconciliation period, including broker and clearing exchange fees, was \$208,159. Broker fees represented 0.02% of the total value of the transactions occurring during the reconciliation period. Ms. Robles testified 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 all transactions made in accordance with NIPSCO's approved electric hedging plan. She testified NIPSCO will continue to solicit input and work with interested stakeholders on any potential changes to its hedging plan as Petitioner's generation portfolio transitions.

Mr. Eckert testified the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs are reasonable. He stated NIPSCO entered into 108 gas and 50 power contracts during October through December 2022.

The Commission finds 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.

E. Purchased Power Over the Benchmark. Ms. Robles described the Purchased Power Benchmark that applies to NIPSCO's purchased power transactions approved in the Commission's August 25, 2010 Order in Cause No. 43526 ("43526 Order"). She testified that in the 43526 Order, the Commission established a mechanism to determine the reasonableness of NIPSCO's purchased power costs. Each day, the cost of any power NIPSCO purchases directly from MISO is compared to a benchmark price. This price is equal to the Platt's Gas Daily Midpoint price for Chicago City Gate, plus a $0.17 per million BTU transportation charge, and then multiplied by the 12,500 BTU/kWh heat rate of a generic gas turbine. Ms. Robles stated power NIPSCO purchased at a price greater than the daily benchmark price is not recoverable from NIPSCO's customers through the FAC. She explained the purchased power transactions subject to the Purchased Power Daily Benchmark are those power purchases that are used to serve FAC load (excluding backup and maintenance contracts) as determined by NIPSCO's Resource Cost and Allocation System, including bilateral purchases for load and MISO Day Ahead and Real Time purchases, except wind power purchases that are excluded in accordance with the 43393, 45194, 45195, and 45310 Orders. In addition to the wind purchases, swap transactions and MISO virtual transactions for generation and load are not subject to the Purchased Power Daily Benchmark. NIPSCO had no swap or virtual transactions during this FAC reconciliation period.

Ms. Robles testified that 9,391 MWhs of purchased power in October 2022 at an average purchased power cost of $70.95/MWh, 9,956 MWhs of purchased power in November 2022 at an average purchased power cost of $53.32/MWh, and 47,208 MWhs of purchased power in December 2022 at an average purchased power cost of $74.65/MWh were in excess of the Purchased Power Benchmark. As a point of comparison, she stated the monthly averages of the Purchased Power Daily Benchmarks were $65.60, $63.45, and $78.81 for October, November, and December 2022, respectively. Ms. Robles testified the MWhs that exceeded the Benchmark in this reconciliation period were not attributable to any one event or factor; rather, the recoverability for each purchase under the terms of the 43526 Order varies. Ms. Robles testified that in accordance with the procedures outlined in the 43526 Order, NIPSCO determined the purchases in excess of the Purchased Power Benchmark were made to supply jurisdictional load that offset available NIPSCO resources MISO did not dispatch or are otherwise eligible under the procedures outlined in the 43526 Order and are, therefore, recoverable.

OUCC witness Guerrettaz testified that in the three months covered by this FAC, 66,555 MWhs exceeded the Purchased Power Benchmark, as Ms. Robles testified. He stated the purchases over the Purchased Power Benchmark were determined to be recoverable, and per OUCC witness Eckert, the OUCC recommends recovery. Mr. Eckert testified Ms. Robles' testimony and workpapers accurately reflect the methodology the Commission approved in the 43526 Order regarding purchased power over the Benchmark. Mr. Eckert noted he has created a working model of Ms. Robles' purchased power over the Benchmark calculations, and he agrees with her calculations.

Based on the evidence, the Commission finds NIPSCO's identified purchased power costs are properly included in the fuel cost calculation, and NIPSCO 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.

8. <u>MISO Day 2 Energy Costs</u>. Ms. Robles stated NIPSCO proposes to recover the fuel-related charges and credits MISO assigned to NIPSCO and attributable to NIPSCO's retail electric customers in accordance with the Commission's Orders in Cause Nos. 42685, 43426, and 43665. The total MISO Components of Fuel Cost included in the actual cost of fuel for October, November, and December 2022 was ($532,000).

Ms. Robles testified Real Time Non-Excessive Energy in October 2022 was $3,331,050, in November 2022 was $1,822,322, and in December 2022 was $8,149,836 primarily due to unit derates and forced outages that occurred after NIPSCO's units cleared in the Day Ahead market, manual dispatch instructions by MISO reducing the generation of NIPSCO's units in the Real Time market, and differences in actual wind production compared to forecasts (due mainly to wind speeds), all coupled with relatively high LMPs. She 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 any month within the reconciliation period.

Mr. Guerrettaz stated NIPSCO provided a breakdown of congestion components, with this information enabling the OUCC to see that congestion is occurring on both day ahead and real time markets. He recommended NIPSCO continue providing this breakout of all congestion components in future FACs.

The forecast of MISO Components of Cost of Fuel in this proceeding, per Ms. Robles, is based on the High – Low average of actual MISO Components of Cost of Fuel incurred for the 12-month period ending December 31, 2022, where the high and low quarters are replaced with a three-year average of the same quarter. She stated NIPSCO included a forecast in this filing of MISO Components of Cost of Fuel of $1,173,557 per month.

9. <u>Estimation of Fuel Cost</u>. In Revised Schedule 1, NIPSCO estimates its total average fuel costs for the billing months of May, June, and July 2023 will be $29,033,187 on a monthly basis.

Ms. Robles noted NIPSCO incorporated forecasted known fixed transportation reservation charges and a related credit associated with Sugar Creek. The actual and forecasted known transportation reservation charges and credit were included on NIPSCO's Attachment 1-A.

Mr. Wagner testified that as of February 6, 2023, NIPSCO's estimated market prices for coal delivery in the forecast period of April, May, and June 2023 were $15.00 per ton for PRB coal, $85.00 per ton for ILB coal, and $92.67 per ton for NAPP coal, excluding transportation costs. He indicated the estimated spot market prices for shipments with March 2023 delivery were approximately $15.00 per ton for PRB coal, $85.00 per ton for ILB coal, and $92.67 per ton for NAPP coal, excluding transportation costs.

Concerning supply reliability, Mr. Wagner testified contracted purchases are forecasted to meet NIPSCO's 2023 coal delivery requirements, and coal producers are obligated to perform under their agreements. NIPSCO has had discussions with all its coal suppliers, and the suppliers indicated they will meet NIPSCO's contracted coal supply requirements. He noted the price of coal used for the forecast period consists of mostly fixed prices. Mr. Wagner testified the average spot market price of coal during the reconciliation period, not including transportation costs (and change from the previous reconciliation period) was $16.28 per ton (down $1.14) for PRB coal, $143.25 per ton (down $36.62) for ILB coal, and $155.61 per ton (down $36.98) for NAPP coal. He stated these prices do not include the cost of transportation, and given the relative illiquidity of coal markets, actual purchase prices can vary from published indices.

In identifying market trends and factors affecting the market for coal and transportation, Mr. Wagner stated wholesale electricity prices fell roughly 37% during the reconciliation period compared with the prior quarter. Schahfer's average 2022 LMPs were up roughly 141% versus 2021 and roughly 186% above the five-year average. He stated coal prices peaked in late summer and declined during the reconciliation period. API 2 (coal delivered to Amsterdam, Rotterdam, and Antwerp ("ARA")) that had bolstered domestic coal prices earlier in 2022 led the decline, with milder than normal weather in Europe pushing coal consumption lower during the reconciliation period. He stated this lower consumption, combined with strong United States thermal coal exports to Europe, resulted in improving ARA inventories. Mr. Wagner advised exports to Asia have also trended lower for the last several months, with lower API 2 prices and mild winter weather in the United States contributing to moderating NAPP and ILB prices.

Mr. Wagner testified the key drivers that had kept upward pressure on electric prices, including strong global energy demand, rising electric demand, high natural gas prices, high coal prices, and high railroad fuel surcharges eased during the reconciliation period; consequently, the resulting United States electric energy supply mix, driven by these market forces, reflects renewable generation was 21% of the mix in 2022 and may increase to 24% in 2023, natural gas-fired generation supplied 39% of the energy in 2022 and is expected to decrease to 38% in 2023, and coal-fired generation provided 20% of the mix in 2022 and is expected to decline to 18% in 2023. Mr. Wagner stated United States coal production increased in 2021 and 2022, but production is expected to fall by 13% in 2023. He stated high natural gas and energy prices during most of 2022 increased the competitiveness of coal generation both domestically and internationally; however, the Energy Information Agency ("EIA") expects natural gas prices to trend lower into 2023. Given relatively high coal prices and the downward pressure on natural gas prices, Mr. Wagner stated coal-fired generation will likely return to the marginal energy source in 2023. In the long run, he projected coal demand will continue to fall, driven by lower natural gas prices and coal generation phasing out of energy markets worldwide. Per Mr. Wagner, these dynamics created significant volatility in all energy markets during the reconciliation period. PRB prices trended lower in early 2022 and remained somewhat flat throughout most of the year. Coal pricing into

Europe (Amsterdam, Rotterdam, and Antwerp) increased drastically in 2022 due to high demand and supply shortages but declined during the reconciliation period. Additionally, coal producers and railroads have typically relied on strong international markets to offset the long-term decline in domestic demand. Strong exports and improved domestic demand during 2022 provided coal producers and coal transporters with increased sales opportunities and price improvements. Mr. Wagner stated the EIA expects coal exports to range between 83 to 93 million tons annually through 2024, which may offset some of the losses in domestic markets.

Mr. Wagner stated the EIA is forecasting domestic coal demand to decline by nearly 11% in 2023 largely due to decreases in the electric power sector driven by coal-fired generation retirements. In addition, the sluggish economic conditions anticipated during early 2023 may put downward pressure on coal and transportation pricing. Per Mr. Wagner, these dynamics have put downward pressure on coal demand globally and should ease supply constraints for coal-fired utility generators in 2023. 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. While the price of coal used for the forecast period consists of mostly fixed prices, Mr. Wagner testified if power prices continue to decrease, there may be decreases in the cost of coal under NIPSCO's indexed coal supply agreement; however, if demand exceeds the forecast and current supply obligations, NIPSCO may need to purchase additional supply which could impact fuel costs during the forecast period.

Mr. Wagner testified Class I railroads have struggled to meet the surge in demand over the last two years and have limited customer shipments for coal as well as other commodities and products they transport. According to Mr. Wagner, coal supply constraints have been caused by reduced investment in coal production and coal transportation projects, supplier bankruptcies, and mine closures over the last several years. He stated these supply and capacity constraints could lead to market volatility if energy demands rebound.

Mr. Wagner testified NIPSCO's cost of coal consumed for generation in the forecast period of April, May, and June 2023 is estimated to be \$67.29 per ton and \$3.357 per million BTU. In developing the forecast period estimate, he stated NIPSCO's fuel supply group incorporates coal contract prices inclusive of adjustments specified in the agreement, dust treatment costs, freeze conditioning costs, railcar lease costs, railcar maintenance costs, estimates of contract prices (fixed price and indexed), 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 ("AILLF") adjustments and estimates of future coal market prices. Additionally, the fuel supply group forecasts beginning inventory values in dollars and quantities in tons for each generation station. These assumptions are provided to NIPSCO's energy supply and optimization group which uses the assumptions to develop the forecast.

Ms. Robles stated NIPSCO completed its forecast for this FAC filing on February 9, 2023, using its production cost modeling system, PROMOD,[3] and made reasonable decisions under the circumstances then known. She noted forward market pricing showed decreases for natural gas and power pricing, falling by approximately 20%-25% from when NIPSCO prepared its original

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

forecast in mid-January to its updated forecast as of February 9, 2023. In her supplemental testimony, Ms. Krupa testified NIPSCO's projected fuel cost charge for the FAC period subsequently decreased from $0.005930/kWh to $0.004477/kWh due to changing market conditions and resulting changes in NIPSCO's forecasts.

Ms. Robles advised the fuel cost factor is forecasted to be $34.341 compared to a base cost of fuel of $26.736. She identified the primary drivers for the forecasted fuel cost factor. First, although forecasted steam generation cost per MWh is anticipated to be lower in FAC 138 than in FAC 137, it is projected to be higher compared to recent steam generation costs due to higher forecasted coal transportation and commodity pricing. Second, purchases through MISO are forecasted to be higher in FAC 138 on a total MWh basis than in FAC 137, and although the forecasted cost per MWh is lower in FAC 138 than in FAC 137, she explained it is projected to be higher compared to recent historical pricing.

To ensure NIPSCO provides electricity to Petitioner's retail customers at the lowest fuel cost reasonably possible, Ms. Robles testified NIPSCO utilized the hedging plan approved in FAC 134 that became effective July 1, 2022, and will continue to utilize financial hedges under the 2022 Hedging Plan to mitigate economic impacts and volatility within each FAC. In addition, NIPSCO has added wind resources and will continue adding new resources to its portfolio. She noted these assets do not have variable fuel costs and are much cheaper relative to utilizing coal-fired (steam) generation. Ms. Robles stated NIPSCO will continue to utilize its growing wind, solar, and solar plus storage assets to economically serve customers.

Mr. Wagner testified two key factors that could impact NIPSCO's coal transportation costs during the forecast period are power prices and the price of HDF. He stated power prices may impact coal transportation costs under two transportation contracts that are indexed to station LMPs. Per Mr. Wagner, contract transportation rates are forecasted using forward energy prices and have maximum rates that ultimately hedge price exposure. With respect to the second factor, i.e., the price of HDF, two coal transportation agreements also have mileage-based fuel surcharges that vary with changes in HDF which can impact transportation costs. Mr. Wagner testified fuel surcharges under these agreements are calculated monthly using the average weekly spot price of HDF, and fuel surcharge estimates are included in rate projections used to develop comprehensive transportation costs for the forecast period. He testified the spot price of HDF as of February 6, 2023, was $4.539 per gallon. Mr. Wagner stated EIA expects improved global refining capacity and improving diesel production will cap distillate prices and expects diesel prices to average $4.23 per gallon during 2023. He testified short-term diesel fuel price volatility may lead to variations in the actual cost of transportation during the forecast period.

Mr. Wagner testified NIPSCO is proactively administering its coal and rail transportation agreements to address any potential coal supply and/or coal transportation shipment issues. In addition, he stated all the anticipated coal supply requirements for 2023 should be met under current supply agreements. That said, Mr. Wagner indicated increased demand for both coal and coal transportation globally has increased the stress on the coal supply chain. He stated most Class I railroads struggled to meet customer demand during the first half of 2022 along all lines of their business, and Class I railroads are required to participate in bi-weekly conference calls with the Surface Transportation Board ("STB") to provide status reports and explain efforts to correct service deficiencies. Mr. Wagner testified NIPSCO and Union Pacific have worked through some of the near-term issues, and in addition to daily operations calls, NIPSCO is meeting bi-monthly with this carrier's operations management to ensure shipments meet forecasted delivery requirements. Mr. Wagner stated NIPSCO also continues to work closely with its other rail carriers to ensure coal deliveries meet demand during the forecast period, and softer market conditions should take pressure off the supply chain. NIPSCO expects deliveries will meet demand.

Mr. Wagner stated the days of coal inventory supply at Schahfer equaled approximately 56 days (up 8 days from the prior quarter) at the end of the reconciliation period. He testified solid railroad performance and lower consumption resulted in increased Schahfer inventory. Michigan City's PRB coal inventory was at 23 days, and its NAPP inventory was at 30 days at the end of the reconciliation period. Mr. Wagner testified NIPSCO has been able to rebuild inventory to target levels since the end of the prior reconciliation period. He stated 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 railcar fleet during the reconciliation period was 1,046 railcars. This equated to seven sets with 16.4% spares. He testified the typical spare railcar pool can range between three and eight percent, but NIPSCO has been in the process of collecting railcars for return, and that led to variations in the spare railcar count. Mr. Wagner testified that during the reconciliation period NIPSCO utilized roughly 71% of its railcar fleet. NIPSCO stored two sets at Schahfer and held one set at Michigan City during Unit 12's outage in October and November 2022. NIPSCO also subleased two sets to a third-party during Michigan City's outage to avoid storage costs. To effectuate this sublease, NIPSCO worked with Union Pacific Railroad prior to the reconciliation period to identify customers requiring railroad supplied cars that could utilize at least two-unit trains. As a result of these efforts, NIPSCO entered into an agreement to lease two 105 car unit trains, enabling NIPSCO to avoid storage costs. Mr. Wagner testified the rate charged the third-party lessee provided revenue to cover the variable operation and maintenance ("O&M") expenses (credited to fuel inventory) and yielded a modest net margin. He stated that while not obligated to do so, NIPSCO will provide this full margin to customers in this FAC; however, because NIPSCO assumes risk by undertaking obligations under any sublease, if future sublease opportunities are identified, NIPSCO reserves the right to seek to retain any sublease margin, net of O&M expenses.

Mr. Wagner testified NIPSCO had no railcars stored at third-party locations and did not incur any long-term storage costs during the reconciliation period. He assured that whenever possible, NIPSCO will utilize Michigan City's or Schahfer's trackage (a zero-cost option) to minimize storage costs. Per Mr. Wagner, NIPSCO has determined Petitioner's fleet size should be reduced to 784 railcars, representing six-unit trains with roughly four percent spares; therefore, Petitioner plans to return 262 railcars by the end of the second quarter of 2023. Mr. Guerrettaz testified it is the OUCC's opinion that over time NIPSCO is achieving a correct level of railcars; provided, NIPSCO should reduce the fleet by 262 railcars by the end of the second quarter of 2023.

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 NIPSCO provided sufficiently detailed testimony and information 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 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, as well as updates upon its efforts to reduce the railcar fleet.

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 2022	$0.043405	$0.049133	13.20%
November 2022	$0.041813	$0.044192	5.69%
December 2022	$0.044549	$0.046237	3.79%
Weighted Average Estimating Error			**7.48%**

Ms. Robles testified the total actual fuel cost in the reconciliation period was $105,242,851 while the forecasted fuel cost was $119,581,200. Thus, the average actual fuel cost per kWh for the reconciliation period was 7.48% less than the forecast. This led to a variance factor of ($3.128), primarily driven by: (1) a combination of lower than anticipated market prices and reduced unit availability experienced this reconciliation period; (2) a lower actual cost associated with the MISO Components Cost of Fuel; and (3) REC sales that helped mitigate potential increases during the reconciliation period. At the time the forecast was prepared, she testified neither NIPSCO nor the market as a whole anticipated (a) an approximate 26% decrease in the average natural gas prices ($5.095/Dth actual compared to $6.901/Dth estimated) for this reconciliation period or (b) an approximate 40% decrease in the all-hours average power price in MISO ($55.07/MWh actual LMP compared to $91.40/MWh estimated LMP) for this reconciliation period. Ms. Robles noted NIPSCO also included the reduction of $1,343,800 from its earnings test and refunded $312,444 to comply with the Cause No. 38706 FAC 130 S2 Order.

Mr. Guerrettaz stated nothing came to the OUCC's attention while reviewing NIPSCO's revised filing indicating the projections NIPSCO used for fuel costs and power sales were unreasonable when comparing actual prior quarter and forecasted fuel costs and sales figures. He stated it is the OUCC's opinion that NIPSCO's initial forecasts prepared in January and February were overstated due to gas and power prices decreasing by as much as 18% after these forecasts, but this change was captured in NIPSCO supplemental testimony filed on March 22, 2023.

The Commission finds, based on the evidence, including Mr. Guerrettaz' testimony upon the reasonableness of NIPSCO's fuel cost and power sales forecast, that NIPSCO's estimate of its prospective average fuel cost to be recovered during the May 2023 through July 2023 billing cycles is reasonable.

10. <u>Return Earned</u>. Subject to Ind. Code § 8-1-2-42.3, Ind. Code § 8-1-2-42(d)(3) requires the Commission to find the FAC applied for will not result in the electric utility earning a return over the return the Commission authorized in the last proceeding in which the utility's basic rates and charges were approved. As discussed below, NIPSCO's evidence demonstrates that for the 12 months ending December 31, 2022, NIPSCO earned a jurisdictional return, including TDSIC revenues, of $285,025,507. This is $4,318,313 more than NIPSCO's authorized amount of $280,707,194, which includes $261,768,564 approved in the applicable rate case, plus $18,938,630 of actual TDSIC operating income during the 12 months ended December 31, 2022; therefore, the Commission finds NIPSCO is earning in excess of that authorized.

Because Petitioner's return exceeds the amount authorized, Ind. Code § 8-1-2-42.3 requires the Commission to determine the amount, if any, of the return to be refunded through the variance in this Cause. A refund is only appropriate if the sum of the differentials (both positive and negative) between the determined return and the authorized return during the relevant period, as defined by Ind. Code §8-1-2-42.3(a), is greater than zero. The overall earnings bank (sum of the differentials) for the relevant period is $85,498,788. Because both the current 12-month test period and the sum of the differentials reflect a position of over-earnings, a reduction in the fuel charge is required. Under the mechanics of the applicable statutes, the Commission finds it is appropriate to reduce NIPSCO's fuel cost factor to reflect the excess return NIPSCO earned during the 12-month period ending December 31, 2022, and after application of the conversion factor, this reduction amount is $1,343,800.

11. <u>OUCC Report</u>. In addition to the testimony referenced above, Mr. Guerrettaz testified: (1) the fuel cost element of NIPSCO's power purchases has been calculated by including the additional requirements of various Commission Orders; (2) the variance for the quarter ending December 31, 2022, was computed in conformity with Ind. Code §§ 8-1-2-42, -42.3, and relevant orders; (3) NIPSCO did have jurisdictional net operating income for the 12 months ending December 31, 2022, greater than granted in its last general rate case; (4) NIPSCO did not have decreases in other operating costs that could be used to offset fuel cost increases; and (5) the figures used in NIPSCO's application for a change in the FAC for the quarter ending December 31, 2022, were supported by Petitioner's books, records, and source documentation for the period reviewed. Mr. Guerrettaz stated the OUCC recommends the revised FAC factor of $0.004477 per kWh be approved. Mr. Guerrettaz also recommended the Commission order NIPSCO to continue to provide: (1) the monthly railcar inventory and explain any deviations from the expected forecast presented; (2) a break out of all congestion components in future FACs; (3) detailed coal cost statements from each supplier to each station for the three actual months on a going forward basis setting forth the components of coal and transportation; and (4) a copy of all new RFPs and contracts for transportation and coal.

Mr. Eckert testified: (1) he created a working model of Ms. Robles' purchased power over the Benchmark calculation and agrees with this calculation; (2) NIPSCO's treatment of Ancillary Services Market ("ASM") 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 steam generation costs are higher than the other large electric investor-owned utilities in Indiana, while NIPSCO's actual monthly cost of fuel (mills/kWh) is comparable to the other large electric investor-owned utilities in Indiana; (5) coal prices increased dramatically over the last 12 months; (6) NIPSCO's coal inventory at Schahfer increased to approximately 56 days, up eight days from its prior FAC filing; (7) NIPSCO's PRB coal inventory at Michigan City Generating Station was at 23 days, and its NAPP coal inventory was at 30 days for the reconciliation period; (8) NIPSCO should continue to update the Commission on its coal inventory; (9) 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; (10) the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs were reasonable; (11) NIPSCO provided information regarding Buffalo Ridge, Barton, Jordan Creek, Rosewater, and Indiana Crossroads; (12) NIPSCO provided an update on the status of the Railroad Litigation[4] and NIPSCO's deferral of associated legal costs and should continue providing such updates; and (13) the OUCC recommends the Commission approve NIPSCO's revised proposed FAC factor as confirmed by Mr. Guerrettaz.

12. Fuel Cost Adjustment Factor. Based on the evidence, the Commission finds NIPSCO has complied with the tests of Ind. Code § 8-1-2-42(d) for establishing a revised fuel cost adjustment and appropriately reduced NIPSCO's fuel cost factor to reflect the excess return NIPSCO earned during the 12-month period ending December 31, 2022. Additionally, Ms. Krupa testified NIPSCO has complied with the Order approved on December 14, 2022, in Cause No. 38706 FAC 130 S2 by sending payment on January 18, 2023, of $393,864 the Commission approved for attorney fees and expenses and then accruing eight percent interest from January 27, 2023, through April 30, 2023, on the remaining amount of $306,137. She stated NIPSCO is refunding $312,444, i.e., the remaining amount NIPSCO initially withheld for potential attorney fees plus eight percent interest through April 30, 2023, to ratepayers via the proposed fuel cost adjustment in this filing.

In Ms. Krupa's supplemental testimony, NIPSCO presented a revised variance factor of ($0.003128) per kWh, composed of the reconciliation and earnings adjustment components, to be added to the estimated cost of fuel for bills rendered during the May through July 2023 billing cycles in the amount of $0.031213 per kWh. This results in a fuel cost adjustment factor of $0.004477 per kWh, after subtracting the cost of fuel in base rates. This is about a 25% reduction when compared to Petitioner's initially proposed factor. NIPSCO's revised estimated average monthly bill impact for a residential customer using 1,000 kWh per month is a $29.80 decrease from the currently approved factor. Mr. Krupa noted NIPSCO's initial FAC factor would have

[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) for allegedly 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").

caused the bill of a residential customer using 1,000 kWh to decrease by $28.35 per month from the currently approved factor.

13. 2023 Hedging Plan.

A. Background and Relief Requested. In the 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 approved in the 43849 Order. In that proceeding, the OUCC and the Industrial Group agreed NIPSCO's proposed process for filing 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. Mr. Campbell testified the 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.

Mr. Campbell 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. 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.

In the 44205 S4 Order, Mr. Campbell stated the Commission expressed a preference to consolidate its annual review of NIPSCO's hedging plans into the FAC process. Accordingly, on September 30, 2016, in Cause No. 44205 S4, NIPSCO notified the Commission that NIPSCO, the OUCC, and the Industrial Group agreed to hold a call annually between December 10 and December 20 to discuss the annual electric hedging plan NIPSCO will propose in its February FAC filing. This affords interested stakeholders 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 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.[5]

In this proceeding, NIPSCO requests Commission approval of its updated energy supply plan covering the two-year period July 2023 through June 2025 (the "2023 Hedging Plan").[6]

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[5] Per Mr. Campbell, in its Notice, NIPSCO stated the stakeholders understand weather events and market forces subsequent to the annual December call could cause NIPSCO to change its 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.

[6] 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 supply plan covering July 2020 through June 2022 (the "2020 Hedging Plan") on April 20,2020, in Cause No. 38706 FAC 126. The Commission approved NIPSCO's 2021 updated energy supply plan covering July 2021 through June 2023 on April 28, 2021, in

B. Evidence Presented. Mr. Campbell supported NIPSCO's 2023 Hedging Plan. He testified that NIPSCO, the OUCC, and the Industrial Group met via a web meeting on December 16, 2022, to discuss the 2023 Hedging Plan, with the proposed plan incorporating stakeholder input received from this meeting.

Mr. Campbell testified the objectives of the 2023 Hedging Plan are to reduce the relative movement in the FAC factor from one period to the next and limit upside price exposure. He explained that Petitioner's initial hedging plan assumed all the coal-fired generation facilities within the NIPSCO asset portfolio were fixed in price. Since a majority of NIPSCO's coal contracts are between three and five years in length, and since coal pricing has historically been less volatile than natural gas pricing and the MISO market price of power, he testified NIPSCO determined any coal-fired generation used to meet the power supply needs of its customers could be classified as a fixed price resource. Mr. Campbell stated any remaining resources that will likely be needed to meet NIPSCO's customers' power supply needs, however, will be classified as floating in price and, thus, considered when developing the hedging plan. He advised the 2023 Hedging Plan also addresses NIPSCO's exposure to natural gas and electricity price volatility associated with supplying electricity to native load customers.

When explaining how the 2023 Hedging Plan is constructed, Mr. Campbell testified that NIPSCO determines the monthly volume of MWhs to be hedged by reviewing the total number of on-peak MWhs that will 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. Mr. Campbell stated the PROMOD model is run 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.

Mr. Campbell testified that in developing the 2023 Hedging Plan, no modifications were made to the existing hedging plan methodology. NIPSCO developed the 2023 Hedging Plan consistent with the FAC filing methodology which is intended to better align the hedging plan with expected market exposure presented in NIPSCO's FAC proceedings. In the 2023 Hedging Plan: (1) forecasted generation was based on the PROMOD economic model; (2) no adjustments were made to the hourly forward-looking power prices; (3) planned outages in year two for coal units were not removed; and (4) an approximate 10%-20% hedge on total forecasted MISO purchased power and gas was sought over the hedging plan program horizon. Mr. Campbell noted the plan is only hedging on-peak MISO purchases to achieve an approximate 10%-20% hedge against total forecasted MISO purchases. He stated this results in higher hedging percentages when only looking at on-peak MISO purchases.

Mr. Campbell testified NIPSCO developed the proposed 2023 Hedging Plan approach in consideration of NIPSCO's shifting generation portfolio. While this portfolio has historically been predominantly traditional forms of generation, NIPSCO is transitioning to a portfolio with more renewable generation resources. Using the FAC filing methodology allows NIPSCO to align the

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Cause No. 38706 FAC 130. The Commission approved NIPSCO's 2022 updated energy supply plan covering July 2022 through June 2024 (the "2022 Hedging Plan") on April 27, 2022, in Cause No. 38706 FAC 134.

hedge to actual market exposure and to have a more direct point of comparison to its quarterly FAC filings, enabling a clearer line to be drawn between the hedging plan and the FAC filings. He stated that maintaining the hedging plan off the FAC filings also allows NIPSCO to make adjustments more easily throughout the year as the availability of its generation fleet and deviations in expected load change. Mr. Campbell testified the proposed target hedging percentages were determined to avoid any stair step growth between the current hedging plan and the 2023 Hedging Plan. He affirmed that 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.

Mr. Campbell stated NIPSCO is operating under the updated 2022-2024 Hedging Plan that began in July 2022. NIPSCO communicated the changes to the 2022 Hedging Plan with its stakeholders on June 16, 2022, and expects to follow the updated 2022 Hedging Plan through June 2023; however, if there are unforeseen, unplanned outages or if there is movement of planned maintenance outages on NIPSCO generating units, Mr. Campbell stated NIPSCO may further modify the updated 2022 Hedging Plan. Per Mr. Campbell, such adjustments are consistent with NIPSCO's past practice of adjusting the hedging plan for material differences in generating unit availability.

Mr. Campbell testified that consistent with previous plans, the 2023 Hedging Plan is comprised of two types of futures contracts. The first type of futures contract (approved in the 43849 Order) will be used to hedge the on-peak MWhs exposure that related to Sugar Creek, a CCGT plant that uses natural gas to generate power. He 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, because there are 10,000 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. Mr. Campbell stated these contracts settle financially as opposed to physically, so they will not impact the physical purchase and delivery of natural gas required to run the Sugar Creek plant. He noted 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.

Mr. Campbell testified the second type of futures contract will be to hedge electric price volatility for the MISO power purchases. He stated NIPSCO purchases power from MISO on a Day Ahead basis. 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 product to hedge the MISO power purchases. Mr. Campbell testified 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. Mr. Campbell explained that if the fixed price is below the average Day Ahead LMP price, NIPSCO will receive payment, and if the fixed price is above the average Day Ahead LMP price, NIPSCO will make a payment.

Mr. Campbell testified the hedges under the 2023 Hedging Plan are being made solely to address native load fuel cost price exposure. He testified 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.

Mr. Campbell also explained NIPSCO's proposal for implementing its hedging transactions. He stated 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. He stated 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. He testified the schedule is broken up into the different types of futures contracts to demonstrate when and what number of contracts will be purchased.

Mr. Campbell testified that 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 take into account market conditions and circumstances known at that time and will use its best judgment in purchasing the futures contracts each month.

Mr. Campbell sponsored an analysis to determine the possible impact of the 2023 Hedging Plan on overall purchased power costs. He testified the analysis shows an example of the additional power supply costs that could be incurred if market prices increase by 20% from where market pricing was as of the close of business on February 7, 2023. He stated that in the example in Attachment 5-E, there could be an additional $31,065,065 of power supply costs (inclusive of CCGT generation and MISO power purchases) if market prices rose by 20% for each month of the plan period (July 2023 to June 2025). He stated the analysis also includes the effect the 2023 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, Mr. Campbell testified the additional power supply costs would be roughly 74% ($23,029,220) in Attachment 5-E 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 $31,065,065 in Attachment 5- E through the plan period if no hedging plan had been implemented. He stated the analysis demonstrates how a hedging plan can reduce volatility in power supply costs. According to Mr. Campbell, while possible savings may be foregone when prices fall, the hedge plan reduces additional costs that may have been incurred when prices rise.

Mr. Campbell testified market conditions are dynamic, and the analysis is only intended to show the relative impact of the program assuming market conditions remain the same as they are today. Nevertheless, he opined that the analysis provides an indication on what sort of impact this program may have in the future. Mr. Campbell testified NIPSCO has in the past recommended adjustments to the hedging plan approach and continues to evaluate factors that could impact the viability of the currently proposed hedging methodology.

Mr. Campbell testified NIPSCO is planning to continue converting 30% of the gas contracts expiring at the start of each January, February, and March into power contracts. He explained this proposal does not alter the current methodology of acquiring gas contracts for Sugar Creek. It simply adds a layer of intra-month hedge protection to address historically higher intra-month price volatility in these months.

Mr. Campbell testified that during the December 16, 2022, stakeholder meeting, no methodology changes were discussed or proposed, but NIPSCO advised stakeholders that it will update pricing and any changes to its maintenance schedule to align with FAC 138. Additionally, NIPSCO relayed that as Petitioner's generation portfolio changes, further refinements to the 2023 Hedging Plan may be needed. He reiterated that NIPSCO will continue to have discussions with its stakeholders about the plan's effectiveness and may in the future make recommendations. Mr. Campbell stated NIPSCO appreciates the collaborative nature of the discussions with the OUCC and the Industrial Group around the overall hedging 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 p. 10. The Commission finds NIPSCO's 2023 Hedging Plan is consistent with the approach approved in the 43849 Order.

Based on the evidence, the Commission finds the 2023 Hedging Plan is reasonable, consistent with the public interest, and should be approved. The evidence demonstrates NIPSCO communicated with the OUCC and the Industrial Group in the interest of improving the plan consistent with prior Orders, and the Commission finds NIPSCO should continue to do so and continue to consolidate the annual review of NIPSCO's hedging plans into the FAC process.

14. 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.

15. Major Forced Outages. Consistent with past Commission Orders, Mr. Saffran sponsored Attachment 4-A describing each major forced outage NIPSCO's generating units experienced during the fourth quarter of 2022, 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 the forced outages for which an analysis was completed at the time of the FAC filing.

Per Mr. Eckert, although the OUCC generally reviews NIPSCO's unit commitment status, the OUCC's FAC audit process focuses more on the cost of fuel and the cost of purchased power.

16. Status of Railroad Litigation. In accordance with the Commission's Order in Cause No. 38706 FAC 125 ("FAC 125"), Ms. Krupa testified the Railroad Litigation remains pending, and as of December 31, 2022, NIPSCO has deferred $3,815,943 in associated legal costs. Mr. Wagner advised the Railroad Litigation continues to be in the discovery phase, with NIPSCO's counsel having deposed the defendants' corporate representatives and providing support to NIPSCO's expert witness in developing the initial expert report. The Commission finds NIPSCO provided an update on the status of the Railroad Litigation as ordered in FAC 125 and should continue doing so in its FAC filings.

17. Confidential Information. On February 17, 2023, NIPSCO filed a motion for protection and nondisclosure of Confidential Information supported by an affidavit showing information to be submitted to the Commission contained trade secrets within the scope of Ind. Code §§ 5-14-3-4 and 24-2-3-2. In a docket entry issued on March 1, 2023, such information was preliminarily found to be confidential, after which NIPSCO submitted the information under seal. The Commission finds such information is 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 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 to bills rendered during the May, June, and July 2023 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 shall continue to include updates in its quarterly FAC filings concerning its utilization of the RECs associated with the wind and solar purchases being recovered through the FAC, as discussed in Finding No. 7.C. 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. 7.D. above.

4. 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, and continue to provide updates on its railcar inventory and efforts to achieve an appropriate railcar level, explaining any deviations that occur.

5. NIPSCO shall continue including in its quarterly FAC filings information related to the 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 assure the OUCC is provided with a copy of all new RFPs and contracts for transportation and coal that are issued.

6. NIPSCO's proposed 2023 Hedging Plan is approved, and NIPSCO shall continue to timely consult with the OUCC and interested stakeholders in developing future hedging plans.

7. If coal decrement pricing is used or forecast, NIPSCO shall file 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, as discussed in Finding No. 7.B. above.

8. NIPSCO shall continue to include in its quarterly FAC filings an update on the Railroad Litigation consistent with the Commission's January 22, 2020, Order in FAC 125 and Finding No. 16 above.

9. NIPSCO shall continue to break out congestion components in its future FAC testimony, provide a cost of coal stacks from each supplier to each station for the three actual months on a going forward basis, and provide a copy of all new requests for proposal and contracts for transportation and coal consistent with the Commission's Order in FAC 137.

10. The information filed in this Cause pursuant to NIPSCO's motion for protective order is deemed confidential pursuant to 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.

HUSTON, FREEMAN, KREVDA, VELETA, AND ZIEGNER CONCUR:

APPROVED: APR 26 2023

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: 2023.04.26 10:51:42 -04'00'

Dana Kosco
Secretary of the Commission