

ORIGINAL

Commissioner	Yes	No	Not Participating
Huston	√		
Freeman	√		
Krevda	√		
Ober	√		
Ziegner	√		

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

**PETITION OF NORTHERN INDIANA PUBLIC)
SERVICE COMPANY LLC FOR APPROVAL OF)
(1) A FUEL COST ADJUSTMENT TO BE)
APPLICABLE DURING THE BILLING CYCLES)
OF FEBRUARY, MARCH, AND APRIL 2022,)
PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE)
NO. 45159, AND (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.)**

CAUSE NO. 38706 FAC 133

APPROVED: JAN 26 2022

ORDER OF THE COMMISSION

**Presiding Officer:
Carol Sparks Drake, Senior Administrative Law Judge**

On November 15, 2021, Northern Indiana Public Service Company LLC (“NIPSCO”) 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 for bills rendered during the February, March, and April 2022 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, and (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. NIPSCO concurrently prefiled its case-in-chief. This included the direct testimony of Kelleen M. Krupa, a Lead Regulatory Analyst for NiSource Corporate Services Company, 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
- Donald L. Bull, Director of Engineering.

On November 15, 2021, NIPSCO also filed a motion requesting confidential treatment for certain information (“Confidential Information”). In a docket entry issued on November 30, 2021, the requested confidential treatment was granted on a preliminary basis.

On November 17, 2021, the NIPSCO Industrial Group (“Industrial Group”) filed a petition to intervene. This petition was granted on November 29, 2021.¹

On December 16, 2021, NIPSCO filed supplemental testimony for Ms. Krupa supporting a revised fuel cost adjustment that is lower than what NIPSCO initially requested.

The Indiana Office of Utility Consumer Counselor (“OUCC”) on December 20, 2021, prefiled the direct testimony and exhibits of the following:

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

NIPSCO filed no rebuttal testimony. A docket entry was issued on December 29, 2021, eliciting responses from NIPSCO primarily related to coal usage at the R.M. Schahfer Generating Station (“Schahfer Station”). On January 3, 2022, NIPSCO filed responses to these docket entry questions.

The Commission noticed this matter for an evidentiary hearing at 9:30 a.m. on January 6, 2022, 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 the evidentiary 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 electricity and the cost of fuel included in the cost of purchased electricity for the months of July, August, and September 2021 averaged \$0.030804 per kWh.

4. Requested Fuel Cost Charge. NIPSCO seeks to change its fuel cost adjustment from the current fuel cost charge of \$0.009761 per kWh for bills rendered during the November 2021 through January 2022 billing cycles to a fuel cost charge of \$0.0124610 per kWh for bills rendered

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.

during the February 2022 through April 2022 billing cycles or until replaced by a different fuel cost adjustment approved in a subsequent filing.

The requested fuel cost adjustment includes a variance of \$8,030,123 that was under-collected during July through September 2021. NIPSCO's estimated monthly average cost of fuel to be recovered in this proceeding for the forecasted billing period of February 2022 through April 2022 is \$30,933,570, and its estimated monthly average sales for that period are 857,487 MWhs.

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

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

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

(3) the fuel adjustment charge applied for will not result in the electric utility earning a return in excess of the return authorized by the Commission in the last proceeding in which the basic rates and charges of the electric utility were approved. However, subject to section 42.3 [Ind. Code § 8-1-2-42.3] 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 September 30, 2021, were \$60,493,689 above the amount the Commission approved in the 45159 Order. NIPSCO's Attachment 1-F also shows its total operating expenses, excluding fuel, for the 12 months ending September 30, 2021, were \$71,808,486 above the amount approved in the 45159 Order. The Commission finds there has been no increase in NIPSCO's actual fuel costs for the 12 months ending September 30, 2021, which has 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 NIPSCO's coal-fired generation provided 75% of energy generated, and 25% 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") coal and Northern Appalachian ("NAPP") coal, and the Schahfer Station having consumed a mix of PRB coal and Illinois Basin ("ILB") coal in Unit 14, PRB coal in Unit 15, and ILB coal in Units 17 and 18.

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 generation cost (fuel and operational costs) or inhibit NIPSCO's ability to comply with emission limits. He testified the reliability of the coal source and the reliability of coal transportation from that source are also critical factors NIPSCO considers.

Mr. Wagner testified that NIPSCO purchased coal during the reconciliation period under three term supply contracts. One of these contracts was with Arch Coal Sales Company for PRB coal, and one contract was with Peabody COALSALLES, LLC for ILB coal. The third agreement was with ACNR (American Consolidated Natural Resources) Coal Sales, Inc. for NAPP coal. Mr. Wagner confirmed NIPSCO has no financial interest in the coal producers currently under contract.

Mr. Wagner testified producers and customers are generally 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 testified that, historically, market-based price adjustments in term supply agreements tend to reduce the buyer's hedging cost 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 fixed prices that increase each year per the contract. In another contract, rates are indexed to generating unit hourly Day-Ahead Locational Marginal Power Prices ("LMPs"). In addition, all of NIPSCO's coal supply agreements adjust the price of coal based on a shipment's quality variances from contract specifications. Mr. Wagner stated that during the reconciliation period NIPSCO also purchased a partial train (65 railcars) of ILB coal from Carbon Partners. This coal was originally loaded at Peabody's Gateway mine for Ingredion, Inc.'s Bedford, Illinois, processing facility. Mr. Guerrettaz noted NIPSCO was able to purchase the 65 railcars of spot coal at a time that had the tightest coal supply in many years, and the OUCC believes NIPSCO did not have a lot of options.

In response to a docket entry question requesting NIPSCO to explain the actions NIPSCO took to ensure the quality of the ILB coal partial train purchase and what actions NIPSCO is taking to ensure an adequate quality and supply of ILB coal is available for the forecast period, NIPSCO advised that it receives quality analyses for each shipment to ensure each shipment meets the quality

requirements under the coal supply agreement. NIPSCO received the mine quality analysis as loaded at the mine from Carbon Partners and determined the 65 cars met specifications. NIPSCO noted that it receives the mine quality analysis for each train and reviews each analysis. If NIPSCO determines the quality does not meet contract specifications, the price is adjusted in accordance with the contract. If the quality exceeds the contract rejection limits or is not reasonably free of debris, NIPSCO may obtain a discount on the coal or reject the shipment. NIPSCO also stated that to ensure adequate quality and supply of ILB coal for the Schahfer Units, NIPSCO entered into a supply agreement for ILB coal for 2022 and 2023, with the volume obligation under that agreement projected to meet NIPSCO's forecasted ILB coal demand for the Schahfer Units.

Mr. Wagner testified the delivered cost of coal consumed by NIPSCO's generating stations for the 12 months ending September 30, 2021, was \$43.12 per ton or \$2.188 per million BTU. The cost of coal consumed during the reconciliation period (July, August, and September 2021) was \$41.73 per ton or \$2.107 per million BTU. The delivered cost of coal consumed during the prior reconciliation period was \$48.08 per ton or \$2.428 per million BTU. When compared to the prior reconciliation period, NIPSCO's delivered cost of coal consumed per ton decreased \$6.35, and the cost was down \$0.321 on a per million BTU basis. Mr. Wagner testified the primary factor that reduced the unit cost of coal expensed during the reconciliation period was the coal inventory survey audit adjustments booked in August. He stated the largest reduction was at Michigan City, with the August adjustments, essentially, offsetting the \$6.00 per ton system increase in the prior quarter that was attributed to the May coal bunker inventory adjustment discussed in FAC 132. A second factor that Mr. Wagner stated contributed to the decrease was the increase in PRB coal consumption relative to ILB coal consumption during the reconciliation period.

In response to a docket entry question inquiring whether there were adjustments or will be any adjustments to the Schahfer coal inventory due to quality or the survey audit, NIPSCO stated quality adjustments for each shipment are made routinely to account for variations from contract guaranteed specifications. For example, if the heat content of a shipment is higher or lower than the guaranteed heat content, the contract rate is adjusted for that shipment. Regarding the survey audits, NIPSCO stated the following adjustments were made during the reconciliation period: Schahfer Unit 14 ILB coal inventory was reduced by 688.76 tons; Units 14 and 15 PRB coal inventory was increased by 52,458.71 tons; and Units 17 and 18 ILB coal inventory was increased by 65,718.98 tons.

As recommended by the OUCC and in accordance with the Commission's request that NIPSCO reconcile the Michigan City coal bunker adjustment included in FAC 132 with the annual aerial inventory adjustment, Mr. Bull provided an explanation of NIPSCO's process for tracking coal transfers and the process for reconciling the coal transfers to assure they are recorded accurately, including recent changes and improvements to the process. He also explained the circumstances that led to the error in the recorded bunker inventory at Michigan City reported in FAC 132. Mr. Bull stated the reconciliation process at Michigan City was fairly complex, as compared to the process at Schahfer Station, and included manual steps that required the judgment of experienced personnel. The station uses a blend of several different coal types, and the blending added to the complexity of the process. Mr. Bull testified the attrition of experienced personnel through retirement and the promotion of the supervising engineer to a new role were contributing factors that led to the coal inventory error. He stated the engineer who assumed responsibility for the process had limited experience and did not utilize the process for updating or validating the correction factors that should have been applied to belt scales. Per Mr. Bull, the bunker balancing process was reestablished at

Michigan City in September 2021 and was improved after a detailed review of all processes used in accounting for coal transfers. He confirmed the improved processes at Michigan City will not change the charges to NIPSCO's customers, as customers are charged for coal as it is consumed in the boiler. The procedure changes only impact NIPSCO's accounting for coal inventory. Mr. Bull testified the process at the Schahfer Station has not materially changed, and it has yielded consistent tracking of bunker coal levels.

Mr. Guerrettaz testified that during the OUCC's audit, NIPSCO was asked many questions about the coal bunker inventory adjustment and related issues. He stated the OUCC was informed that additional internal control procedures are being developed and will be implemented when finalized. In addition, NIPSCO will provide the OUCC with a copy of the final version of these procedures.

Ms. Robles testified there were no changes to NIPSCO's gas purchasing practices for NIPSCO's generation located on or off NIPSCO's gas distribution system (Sugar Creek) during the reconciliation period. She opined that NIPSCO has made every reasonable effort to purchase natural gas so as to provide its customers with electricity at the lowest reasonable price.

Based on the evidence presented, the Commission finds NIPSCO has adequately explained its coal and gas procurement decision making, and its acquisition process is reasonable. Regarding the inventory adjustment related to NIPSCO's coal bunkers at Michigan City, in FAC 132 NIPSCO was directed to update the Commission, the OUCC, and other interested stakeholders about this issue in FAC 133. Given the evidence, the Commission finds NIPSCO has complied.

B. Coal Decrement Pricing. Mr. Wagner testified NIPSCO does not currently anticipate utilizing decrement pricing but will continue to update the Commission upon 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 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. Pursuant to 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 will begin 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”) in late November or early December 2021; therefore, costs associated with the wholesale purchase and sale agreement for wind energy with Indiana Crossroads are also included in NIPSCO’s forecasted fuel costs. Consistent with the 43393, 45194, 45195, and 45310 Orders, NIPSCO is also crediting any off-system sales created by its wind PPAs. She stated the wind PPA adjustment for the forecast period (January, February, and March 2022) is based on the average actual wind PPA adjustment incurred for the 12-month period ended September 30, 2021. For the reconciliation period of July, August, and September 2021, NIPSCO received 67,799 MWhs, 81,927 MWhs, and 151,282 MWhs, respectively.

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 set its own regulations upon how to qualify and account for RECs. Ms. Robles testified that as of this filing, NIPSCO receives RECs associated with the power it purchases from Barton, Buffalo Ridge, Jordan Creek, and Rosewater. She stated all RECs are or will be tracked in a renewable energy tracking system. During this FAC period, she testified current vintage RECs were sold. The block sizes and proceeds from the sales were: (1) 50,000 with net proceeds of \$390,000; (2) 70,000 with net proceeds of \$560,000; (3) 15,133 with net proceeds of \$66,290; (4) 50,000 with net proceeds of \$450,638; (5) 68,400 with net proceeds of \$650,159; (6) 40,245 with net proceeds of \$356,772; (7) 58,783 with net proceeds of \$608,404; (8) 25,000 with net proceeds of \$253,638; and (9) 25,000 with net proceeds of \$253,638, for total RECs sold of 402,561 and total net proceeds of \$3,589,537. In addition, NIPSCO included a prior period charge of \$928 for broker fees.

Ms. Robles testified that NIPSCO will continue to pass the proceeds from the sale or transfer of RECs back to its customers through the “Purchased Power other than MISO” line item. She noted that as evidenced by NIPSCO’s sales, REC prices are increasing, resulting in increased REC sales revenue being passed back to NIPSCO’s customers. Per Ms. Robles, NIPSCO continually evaluates the marketability for all RECs, and as the possibility for future legislation evolves, NIPSCO will appropriately changes its REC strategy.

Ms. Robles stated NIPSCO now has 24 approved solar and wind 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, Ms. Robles testified current vintage solar and wind FIT RECs were sold. The block sizes and sale proceeds were: (1) 3,214 with net proceeds of \$14,784; (2) 3,314 with net proceeds of \$6,118; and (3) 14 with net proceeds of \$62. Ms. Robles stated NIPSCO has and will continue 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 FIT RECs.

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

Ms. Robles testified NIPSCO is not expecting to buy firm, long-term purchased power during the forecast period and did not enter into 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 that NIPSCO incorporated forecasted FIT purchases for the forecast period based on the average of actual FIT purchases incurred for the 12 months ending September 30, 2021. She testified NIPSCO also incorporated forecasted known fixed transportation reservation charges and a related credit associated with Sugar Creek.

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 Cause Nos. 43393, 45194, 45195, and 45310 and any other future renewable purchases.

D. Electric Hedging Program. Ms. Robles testified the table below shows the hedging contracts purchased during the reconciliation period.

Month	Power Contracts		Gas Contracts	
	Actual	Var to Plan	Actual	Var to Plan
July 2021	20	0	66	0
August 2021	25	0	66	0
September 2021	10	0	63	0

Ms. Robles stated the execution of these contracts was consistent with NIPSCO’s approved electric hedging plan through September 2021. She stated NIPSCO continues to operate under the 2021-2023 hedging plan as approved in Cause No. 38706 FAC 130.

Ms. Robles testified the impact of the hedges during the reconciliation period was a gain of \$2,209,634. She stated the net total impact of the hedging plan in this FAC reconciliation period, including broker and clearing exchange fees, was \$2,205,262. 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.

Mr. Eckert testified the OUCC reviewed NIPSCO’s hedges and believes the hedging costs are reasonable. He testified that NIPSCO entered into 195 gas and 55 power contracts during July through September 2021.

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.

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 Midcontinent Independent System Operator, Inc. ("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 that 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 51,639 MWhs of purchased power in July 2021 at an average purchased power cost of \$53.71/MWh, 55,524 MWhs of purchased power in August 2021 at an average purchased power cost of \$64.86/MWh, and 18,024 MWhs of purchased power in September 2021 at an average purchased power cost of \$75.39/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 \$47.18, \$51.00, and \$62.09 for July, August, and September 2021, 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 stated all purchases over the Benchmark were determined to be recoverable, and recovery is recommended by OUCC witness Eckert. Mr. Eckert testified that 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 purchase 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. MISO Day 2 Energy Costs. Ms. Robles stated 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 July through September 2021 was \$4,837,712.

Ms. Robles testified the Real Time Non-Excessive Energy in July 2021 was \$4,126,543; \$2,626,104 in August 2021; and \$3,018,402 in September 2021. The primary drivers of these amounts were unit derates and forced outages that occurred after NIPSCO's units cleared in the Day Ahead market as well as differences in actual wind production compared to the forecast. Real Time Asset Energy in August 2021 was \$1,095,120, primarily due to next day hourly weather forecast variations and inaccurate industrial load forecasts that customers provided. 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 \$2 million in any month during the reconciliation period in this proceeding.

Ms. Robles noted that in the FAC 132 Order the Commission ordered NIPSCO to proactively continue to interact with MISO to determine the factors that drove higher congestion amounts during April 2021 associated with the Jordan Creek facility and to explain these in its next FAC filing and how this congestion and any financial impact upon ratepayers will be mitigated, as well as engage in substantive discussions with the OUCC upon these matters. Ms. Robles testified that when NIPSCO has previously reached out to MISO, MISO informed NIPSCO it does not publish or disclose sensitive information that would reveal specific causes of and contributing factors to congestion. Additionally, MISO has said the congestion could be due to factors outside its footprint and within other RTOs. Ms. Robles stated that during the September 2021 OUCC on-site audit for FAC 132, NIPSCO discussed with the OUCC how the increased congestion costs for April 2021 for the Jordan Creek facility were due to a transmission outage that affected this facility, and she provided a copy of MISO's related communication. In addition, Ms. Robles testified the congestion costs reported in FAC 132 for Jordan Creek were related to the difference in LMP between NIPS.NIPS and Jordan Creek commercial pricing nodes and were not, for example, related to extensive amounts of negative LMPs at Jordan Creek. According to Ms. Robles, during this particular reconciliation period, NIPSCO did not incur any significant congestion costs whose net costs exceeded \$2 million. Additionally, NIPSCO continues to review the FTR process, including FTRs for its new resources, and is waiting to see if ARRs will be awarded to the new resources. With respect to NIPSCO working with MISO, she reiterated that NIPSCO has previously reached out to MISO on the specific Jordan Creek issue discussed during FAC 132, and MISO's position is to not provide detailed explanations about the causes of congestion. She opined that it is unlikely MISO will provide specifics around congestion, dispatch, and commitment.

Ms. Robles further explained that with the retirement of most of NIPSCO's coal fleet by 2023, these units are being replaced by a projected 14 individual projects, and in the CPCN filings associated with these 14 projects, congestion costs were incorporated into the estimated Levelized Cost of Energy ("LCOE"). Ms. Robles testified these costs were included without any anticipated impacts from FTRs, recognizing that any future FTRs are best determined following NIPSCO gaining experience with actual unit operations. She confirmed that NIPSCO will, however, continue to work with interested stakeholders during the quarterly FAC process to answer any questions related to Jordan Creek or other resources. Ms. Robles testified that many factors play into the determination of the congestion component of the LMP that are outside of NIPSCO's control, but NIPSCO, in an effort to reduce potential congestion impacts, may choose to employ the use of FTRs. She stated NIPSCO continues to evaluate and review potential FTR needs for all its resources, including Jordan Creek, and will continue to: (1) monitor the delta between the NIPS.NIPS load zone and the new generation nodes; (2) gain history with the new resources; (3) choose to employ the use of FTR options in the

best interest of its customers, and (4) is committed to working with interested stakeholders to educate, inform, and solicit input into FTR procurement.

OUCC witness Guerrettaz testified that Real Time Non-Excessive Energy exceeded \$9.7 million in this FAC, with this appearing to be the highest amount ever and \$3.3 million higher than the amount in FAC 132. Mr. Guerrettaz stated that during the OUCC's audit, NIPSCO advised that almost 60% of the Real Time Non-Excessive Energy was due to Jordan Creek. He stated it is the OUCC's understanding that the increase in this charge type was due to the difference between the day ahead offer and the real time offer, with NIPSCO to provide the OUCC with additional information. Mr. Guerrettaz testified NIPSCO also advised the OUCC it had follow-up discussions and emails with MISO after the last FAC proceeding and presented an updated chart showing the trends in this cost. Per Mr. Guerrettaz, it appears the congestion has been relieved in the months following the additional charges.

Ms. Robles testified the forecast of MISO Components of Cost of Fuel in this proceeding is based on the High-Low average of actual MISO Components of Cost of Fuel incurred for the 12-month period ending September 30, 2021, where the high and low quarters are replaced with a three-year average of the same quarter. In this filing, NIPSCO included a forecast of MISO Components of Cost of Fuel in the amount of \$967,714 per month.

We find the evidence unclear upon the extent to which NIPSCO has sought additional information from MISO since FAC 132 concerning its higher congestion amounts but does explain NIPSCO's experience in making such MISO inquiries. The Commission finds NIPSCO should continue to work with the OUCC and other interested stakeholders regarding this congestion and how best to manage and mitigate any related financial impact upon ratepayers and apprise the Commission of these efforts in its next FAC filing (FAC 134).

9. Estimation of Fuel Cost. NIPSCO estimates its total average fuel costs for February 2022 through April 2022 will be \$30,935,570 on a monthly basis.

Mr. Wagner testified that as of November 5, 2021, NIPSCO's estimated market prices for delivery in the forecast period of January, February, and March 2022 were \$37.00 per ton for PRB coal, \$84.50 per ton for ILB coal, and \$115.00 per ton for NAPP coal, excluding transportation costs. As of November 5, 2021, the spot market prices for shipments with December 2021 delivery were approximately \$37.00 per ton for PRB coal, \$84.50 per ton for ILB coal, and \$115.00 per ton for NAPP coal, excluding transportation costs. Mr. Wagner testified coal prices increased dramatically during this reconciliation period, especially toward the end of the quarter, and wholesale electricity prices continued their steady climb due to a number of factors, including strong global demand, high natural gas prices, increased coal demand, and constrained gas and coal supply. He stated MISO's LMPs increased significantly during 2021 driven by increased demand and higher natural gas, coal, and oil prices. Mr. Wagner noted the Schahfer Station's average 2021 LMPs were up roughly 71% versus 2020 and 35% above the five-year average. The Energy Information Administration ("EIA") expects retail electricity demand may rise 3.0% in 2021 led by a strong, weather driven first quarter and the economy continuing to recover from the 2020 pandemic. Mr. Wagner stated the EIA also predicts United States coal production to increase 10% in 2021 when compared with 2020 production levels, driven by higher natural gas prices that have allowed coal generation to regain some of the market share lost to natural gas generation over the last several years. Despite the expected increase

in coal demand, he testified coal generation will likely remain the marginal energy source in the power market in the long run as coal generation continues to be phased out. Mr. Wagner testified that in 2020, natural gas led United States electric power sector generation at 39%; non-hydro renewables comprised 12% of the electricity generated, and coal generation's share was 20%, down from 24% during 2019 and down from the peak share of roughly 48% of the generation mix in the early 2000s. Mr. Wagner stated that for 2021, EIA estimates coal generation's share will recover to 24% at the expense of natural gas generation, which is expected to fall to roughly 36%, with non-hydro renewables' market share expected to increase in 2021 to 14%.

Mr. Wagner testified that as of early November 2021, spot natural gas prices were \$5.73 per million BTU, with the EIA expecting natural gas prices to average \$5.80 during the fourth quarter of 2021 and fall back to an average of \$4.01 per million BTU in 2022. These dynamics, per Mr. Wagner, have created significant volatility in all energy markets and pushed PRB coal pricing to an all-time high, with NAPP and ILB coal prices three to four times higher than a year ago. Mr. Wagner stated coal producers and railroads typically relied on strong international markets to offset the long-term decline in domestic demand; however, demand from international markets for coal decreased 40% when compared to 2018 (the five-year peak), and this kept NAPP and ILB coal prices relatively low, but this trend has substantially reversed. Per Mr. Wagner, exports increased dramatically during 2021 and are expected to be 34% higher than the 2020 export rate. As a result of strong exports and robust domestic demand, coal producers and coal transporters have experienced increased sales opportunities and improved prices. Mr. Wagner stated these market conditions have created coal supply shortages that led to considerably higher coal prices. NIPSCO has surveyed its coal suppliers, and they indicated they have little to no surplus coal production and are, essentially, sold out for the remainder of 2021 and 2022.

Mr. Wagner stated Class I railroads are struggling to meet the surge in demand and have limited customer shipments. He testified the underlying supply constraints have been caused by reduced investment in coal production and coal transportation projects over the last several years. When combined with the unexpected increase in coal demand, Mr. Wagner stated this has strained the coal supply chain; consequently, it is expected that high electricity and natural gas prices and coal supply and transportation constraints will keep upward pressure on coal prices throughout 2021 and into 2022, but the long-term global trend to aggressively reduce fossil fuel generation will likely keep a ceiling on coal and transportation pricing and financially strain coal suppliers' and railroads' transportation businesses in the long run.

Mr. Wagner testified NIPSCO's cost of coal consumed for generation in the forecast period of October, November, and December 2021 was estimated to be \$54.05 per ton and \$2.628 per million BTU. He stated prices for NIPSCO's coal deliveries in the quarterly forecast period are fixed in most supply contracts. One contract is indexed to station LMPs. With power prices increasing in 2021, there may be increases in the delivered cost of coal under the indexed supply agreement, but he stated this contract has maximum rates and ultimately hedges price exposure. Mr. Wagner testified NIPSCO has had multiple discussions with all of its coal suppliers, and they indicated they will meet NIPSCO's contracted coal supply requirements.

Mr. Wagner testified the average spot market price of coal during the reconciliation period (and change from the previous reconciliation period) was \$13.87 per ton (up \$1.87) for PRB coal, \$46.28 per ton (up \$14.51) for ILB coal, and \$57.78 per ton (up \$15.86) for NAPP coal. He noted

these are average F.O.B. spot market prices and do not include transportation costs. Given the relative illiquidity of coal markets, actual purchase prices may vary from published indices.

Mr. Wagner 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 (seasonal) costs, railcar lease and maintenance costs, estimates of contract prices (fixed price and indexed contract prices using forward LMP price estimates), estimates of transportation fuel surcharges using the current price of On-Highway Diesel Fuel ("HDF"), estimates for the Association of American Railroad's All Inclusive Index Less Fuel ("AAILF") adjustments, and estimates of future coal market prices. In addition, he testified the fuel supply group provides a forecast of beginning inventory values in dollars and quantities in tons for each generating station. These assumptions are provided to NIPSCO's energy supply and optimization group which uses the assumptions to develop the forecast for the period. Ms. Robles testified that NIPSCO completed its forecast for this FAC filing on November 8, 2021, using its production cost modeling system, PROMOD,³ and made reasonable decisions under the circumstances then known.

In responding to a docket entry question requesting NIPSCO to identify and explain the key drivers of the disparity between the estimates for the Purchases through MISO (77.753 as the unit cost (mills/kWh)) in Revised Attachment 1-D and 57.103 mills/kWh in Attachment 1-D, NIPSCO advised that in Attachment 1-D, more purchases were estimated to be made in the off-peak hours, lowering its average purchased power cost. In Revised Attachment 1-D, as a result of lower forward looking gas prices, estimated generation from NIPSCO's combined cycle unit increased and reduced the need to purchase power, especially during the off-peak period. As such, the estimate disparity is mainly estimated purchases made during the on-peak period when customer demand and purchase power costs are typically higher.

Ms. Robles stated that to ensure NIPSCO provides electricity to its retail customers at the lowest fuel cost reasonably possible, NIPSCO has an approved hedging plan from FAC 130 that became effective July 1, 2021, and NIPSCO will utilize these financial hedges to mitigate economic impacts and volatility within each FAC. In addition, NIPSCO has renewable resources coming online that 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 growing wind, solar, and solar plus storage assets to economically serve customers.

Mr. Wagner testified NIPSCO has two coal transportation agreements with rates that are indexed monthly to station LMPs and have mileage-based fuel surcharges that vary with changes in HDF. He testified these pricing structures and the anticipated cost of fuel surcharges are included in the rates used to develop the forecast of delivered coal costs. Mr. Wagner stated transportation rates are estimated using forecasted LMPs, and fuel surcharges are calculated monthly using the average weekly spot price of HDF. He testified the spot price of HDF as of November 8, 2021, was \$3.730 per gallon, noting HDF prices increased 43% since the beginning of the year and are above the 2021 prices EIA forecasted. Mr. Wagner stated HDF prices are expected to stabilize and remain somewhat flat through the end of 2021 and into 2022. Notwithstanding, per Mr. Wagner, any increases in HDF prices will increase railroad fuel surcharges under one transportation agreement. He advised that a

³ PROMOD is NIPSCO's electric forecasting model.

second transportation agreement has adjustments that begin when HDF prices are above \$3.49 per gallon, and NIPSCO anticipates fuel surcharges under this agreement will likely be applied starting in December 2021.

With respect to reliability, Mr. Wagner testified NIPSCO's rail carriers have been reliable with the exception of PRB deliveries to Michigan City in October. The uptick in coal demand has, however, put increased pressure on the supply chain and, per Mr. Wagner, could impact railroad performance, especially if there are significant weather events or other unforeseen disruptions. 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 of the anticipated coal supply requirements for 2022 have been covered. That said, Mr. Wagner indicated the increase in demand for coal and coal transportation globally has increased the stress on the coal supply chain; consequently, NIPSCO has had multiple discussions with its coal suppliers and railroads and expects coal deliveries will meet demand during the forecast period, but current market conditions have increased the risk of performance issues and/or supply disruptions. He assured that NIPSCO is continually monitoring coal supplier and railroad performance and will pursue any performance issues.

Mr. Wagner stated the days of supply at the maximum burn measure for coal inventory at Schahfer equaled approximately 31 days (down 11 days from the prior quarter) at the end of the reconciliation period. He testified higher than anticipated demand resulted in this lower inventory. Michigan City's coal inventories were at target levels at the end of the reconciliation period. Mr. Wagner testified NIPSCO has made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible.

Mr. Wagner testified NIPSCO's railcar fleet size at the beginning of 2021 was 1,469 railcars. This equated to 11 unit trains (125 railcars per train) with 6.4% spares. He testified NIPSCO returned 318 railcars to lessors year-to-date and reduced the total set count to eight unit trains plus spares. Per Mr. Wagner, the spare railcar pool was roughly 13% at the end of the reconciliation period. As Mr. Wagner has previously testified, the typical spare railcar pool is roughly eight percent, but NIPSCO is in the process of collecting railcars for return, and that could lead to variations in the spare railcar count. Mr. Wagner testified NIPSCO utilized roughly 83% of its railcar fleet during July, 95% in August, and 100% in September 2021. He stated strong coal demand and reduced set count resulted in increased fleet utilization during the reconciliation period. According to Mr. Wagner, PRB shipments for Schahfer Unit 15 were required during the third quarter to safely reduce inventory while maximizing the recovery of coal from inventory and to support generation reliability, with Unit 15 retired on October 1, 2021. He noted NIPSCO expected utilization to increase to 100% during the third quarter given the increased need for PRB coal shipments for Unit 15 and the fleet size reduction.

Mr. Wagner stated NIPSCO returned 99 railcars in early 2021 and planned to return an additional 550 railcars at a rate of 25% by the end of the second quarter, another 50% by the end of the third quarter, and the remaining 25% by year-end. He stated 40% of the 550 cars were returned by the end of the third quarter. In addition, NIPSCO removed all sets from third party storage locations during the reconciliation period, eliminating storage costs; however, NIPSCO's increased utilization due to strong coal demand has delayed the return process. Mr. Wagner testified current market conditions have created significant supply chain risks; therefore, NIPSCO will continue to prioritize coal shipments over the sorting and return of railcars. In addition, the Class I railroads have limited

resources, and this, according to Mr. Wagner, has limited NIPSCO's ability to return railcars to lessors. That said, NIPSCO is continuing efforts, as market conditions allow, to return up to 331 railcars (roughly 2 sets plus spares) to lessors between now and the end of 2022 to better match the railcar fleet capacity with anticipated coal delivery requirements. Mr. Guerrettaz testified NIPSCO's average railcar utilization rate this quarter was 93%. He noted NIPSCO provided a detailed chart that sets forth, by month, the total railcars and the number of railcars returned, and he recommended NIPSCO be required to continue to provide the monthly railcar inventory and explain deviations from the forecasted return timeline.

In addressing prospective improvements to the generating station heating sheds and what freeze treatments are being used, Mr. Wagner noted that as he has previously testified, the heating shed at Schahfer is not used because it was not effective in aiding the removal of frozen coal. For Michigan City, NIPSCO continues to evaluate the effectiveness of the heating shed in its current configuration, and station personnel are making improvements to the heating shed. He testified that use of the heating shed is currently based on the condition of a given train and is, ultimately, at the discretion of station management and fuel handling supervisors. Mr. Wagner testified that Michigan City fuel handling supervision has indicated the heating sheds at Michigan City are used during light to moderate freezing conditions with mixed results. He stated NIPSCO will continue to follow industry standards for frozen coal management. Mr. Wagner advised that utilities typically use freeze treatments and side release chemical agents to lessen the impacts of frozen coal. NIPSCO directs the mines to start freeze treatments on November 1 and to continue this treatment through March. Mr. Wagner stated PRB mines apply side release to empty railcars before they are loaded, while ILB and NAPP coal mines, as directed by NIPSCO, apply side release and full body freeze treatment depending on the severity of the weather. Mr. Wagner noted the efficacy of freeze treatments can be substantially diminished in severe weather conditions, even at maximum application rates.

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 in 2021-2022.

In the Commission's January 23, 2019, Order in Cause No. 38706 FAC 121, NIPSCO was ordered to continue including in its FAC filings covering winter months information about improvements to the generating station heating sheds and any freeze treatment used, as earlier ordered

in Cause No. 38706 FAC 118. The Commission finds NIPSCO provided this information and should continue to include information about improvements to generating station heating sheds and any freeze treatment used in its FAC filings covering winter months.

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

<u>Month</u>	<u>Actual Fuel Cost</u> <u>\$/kWh</u>	<u>Estimated Fuel Cost</u> <u>\$/kWh</u>	<u>Estimating Error:</u> <u>Over (Under)</u>
July 2021	\$0.032928	\$0.028947	-12.09%
August 2021	\$0.032003	\$0.028199	-11.89%
September 2021	\$0.027616	\$0.027553	-0.23%
Weighted Average Estimating Error			-8.23%

Ms. Robles testified the average actual fuel cost per kWh for the reconciliation period was 8.23% greater than the forecast. This led to a variance factor of \$3.122 primarily driven by: (1) warmer than normal temperatures experienced in this FAC period, especially in August and September, with increased cooling degree days impacting demand; (2) higher than anticipated market prices during this FAC period, allowing NIPSCO’s available coal fleet more opportunity to be called upon by MISO; and (3) periods of reduced availability at NIPSCO’s coal generation and Sugar Creek combined cycle plant during this reconciliation period. She explained that at the time the forecast was prepared, neither NIPSCO nor the market anticipated an approximate 67% increase in the average natural gas prices (\$4.307/Dth actual compared to \$2.584/Dth estimated) for this reconciliation period or an approximate 27% increase in the all hours average power price in MISO (\$41.06/MWh actual LMP compared to \$32.40/MWh estimated LMP). Per Ms. Robles, while there was a substantial increase in the actual costs when compared to forecasted costs, NIPSCO’s renewable sales were strong, and NIPSCO’s hedge program performed well, helping to mitigate potential further increases in the impact during the reconciliation period.

Mr. Guerrettaz stated nothing came to the OUCC’s attention during the review of NIPSCO’s revised filing indicating the projections NIPSCO used for fuel costs and power sales were unreasonable when comparing prior quarter actual and forecasted fuel costs and sales figures. He testified that during the OUCC’s audit, NIPSCO indicated natural gas and power prices had dropped since NIPSCO’s original forecast; therefore, on December 16, 2021, NIPSCO filed revised testimony and exhibits supporting a new factor based on a new forecast. He testified the OUCC reviewed both the original and revised version of the PROMOD runs for accuracy.

The Commission recognizes that NIPSCO’s forecasted cost of fuel is increasing, as acknowledged by both NIPSCO and the OUCC; however, based on the evidence, including Mr. Guerrettaz’s testimony upon the reasonableness of NIPSCO’s fuel cost and power sales forecast, the Commission finds NIPSCO’s estimate of its prospective average fuel cost to be recovered during the February 2022 through April 2022 billing cycles is reasonable.

10. Return Earned. NIPSCO’s evidence demonstrates that for the 12 months ending September 30, 2021, NIPSCO earned a jurisdictional return, including FMCA and TDSIC revenues,

of \$253,973,197. This is \$22,782,405 less than NIPSCO's authorized amount of \$276,755,602, which includes \$264,626,783 approved in the applicable rate case, plus \$12,128,819 of actual ECRM, FMCA, and TDSIC operating income during the 12 months ended September 30, 2021. The overall earnings bank (sum of the differentials) for the relevant period is a negative \$158,849,083. Based on the evidence presented, the Commission finds that for the 12 months ending September 30, 2021, NIPSCO did not earn a return exceeding that authorized in its last base rate case, as appropriately adjusted.

11. OUC Report. 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 September 30, 2021, was computed in conformity with Ind. Code §§ 8-1-2-42, -42.3, and relevant orders; (3) NIPSCO did not have jurisdictional net operating income for the 12 months ending September 30, 2021, 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; (5) the figures used in NIPSCO's application for a change in the FAC for the quarter ending September 30, 2021, were supported by Petitioner's books, records, and source documentation for the period reviewed; and (6) the fuel cost adjustment for the quarter ending September 30, 2021, has been accurately applied. Mr. Guerrettaz stated the OUC recommends the FAC factor of \$12.461 mills per kWh be approved as requested but also recommends NIPSCO be required in its next FAC filing to: (1) continue to break out congestion cost at Jordan Creek; (2) provide further analysis and details regarding the high excessive energy charges and how these charges can be limited as the NIPSCO generation fleet changes to renewables; and (3) update the Commission on NIPSCO's return of 550 railcars by providing monthly railcar inventory and explaining any deviations from the forecast presented.

Mr. Eckert testified: (1) he has 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 and actual monthly cost of fuel (mills/kWh) are comparable to the other large electric investor-owned utilities in Indiana; (5) NIPSCO's coal inventory at Schahfer decreased to approximately 31 days, which is down 11 days from its prior FAC filing; (6) NIPSCO should continue to update the Commission on its coal inventory; (7) 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; (8) the OUC reviewed NIPSCO's hedges and believes the hedging costs were reasonable; (9) NIPSCO provided information regarding Buffalo Ridge, Barton, Jordan Creek, and Rosewater; (10) NIPSCO provided an update on the status of the Railroad Litigation⁴ and NIPSCO's deferral of associated legal costs; and (11) the OUC recommends the Commission approve NIPSCO's revised proposed FAC factor as confirmed by Mr. Guerrettaz.

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

Additionally, Mr. Eckert noted that natural gas prices have decreased. He stated that in its original filing, NIPSCO utilized forecasted prices when purchased power and natural gas prices were extremely high, but since NIPSCO's filing, purchased power and natural gas prices have decreased, prompting NIPSCO to recalculate its FAC factor. He stated NIPSCO determined it was appropriate to revise its filing, lowering the FAC factor from \$0.014260 to \$0.012461.

12. 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 \$0.003122 per kWh to be added to the estimated cost of fuel for bills rendered during the February 2022 through April 2022 billing cycles in the amount of \$0.036075 per kWh. This results in a fuel cost adjustment factor of \$0.012641 per kWh, after subtracting the cost of fuel in base rates and adjusting for applicable taxes. Ms. Krupa testified the new FAC factor is \$0.001799 less than the factor NIPSCO initially filed on November 15, 2021, which is a reduction of about 13% when compared to the originally proposed factor. She stated the estimated average monthly bill impact for a residential customer using 1,000 kWh per month is an increase of \$2.70 from the current factor.

13. Interim Rates. Because the Commission is unable to determine whether NIPSCO will earn an excess return while this Order is in effect and because the Commission has opened a subdocket to determine whether NIPSCO acted reasonably and prudently in connection with the events leading to the fire at Schahfer and in responding to it, along with the associated impact, if any, of the Schahfer outage on FAC costs, 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 Attachment 4-A describing each major forced outage NIPSCO's generating units experienced during the third quarter of 2021, 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 case analysis for forced outages, if an analysis was completed at the time of the FAC filing.

In response to a docket entry question concerning a forced outage at Schahfer Unit 18 during the third quarter, NIPSCO advised: (a) it has not had an issue with high rock content in the 24 months prior to the issue at Unit 18; (b) the high rock content caused poor grindability in four coal pulverizers; (c) a high rock content is not currently a concern when operating the Schahfer coal units; (d) the coal with the high rock content was taken from around the bottom of the coal pile due to low inventory levels, with a contingency plan now in place if high rock content is again experienced; and (e) NIPSCO received no remuneration due to the high rock content in the ILB coal. Because the coal was taken from near the bottom of the pile, it was likely there a long time, with the origin of the rocks and debris not determined.

15. 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

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").

as of September 30, 2021, NIPSCO has deferred \$1,397,153 in associated legal costs. Mr. Wagner advised depositions are being taken and/or scheduled in this case. The Commission finds NIPSCO provided an update on the status of the Railroad Litigation as ordered in FAC 125 and should continue doing so.

16. Confidential Information. On November 15, 2021, 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 November 30, 2021, 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 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 February 2022 through April 2022 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. 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 shall continue to include in its quarterly FAC filings updates concerning its utilization of the RECs associated with the wind purchases being recovered through the FAC, as discussed in Finding No. 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 shall also provide updates on its efforts to return 550 railcars during 2021-2022.

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

6. NIPSCO shall break out the congestion cost at Jordan Creek in its next FAC filing and provide further analysis and details upon high excessive energy charges and how these charges can be limited as NIPSCO's generation fleet transitions to renewables, as well as continue to engage in substantive discussions with the OUCC upon these matters.

7. 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. 15 above.

8. 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.

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

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

APPROVED: JAN 26 2022

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

Dana Kosco
Secretary of the Commission