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 2021, 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 AND 45195.

CAUSE NO. 38706 FAC 129

APPROVED: JAN 20 2021

ORDER OF THE COMMISSION

Presiding Officer:
Carol Sparks Drake, Senior Administrative Law Judge

On November 16, 2020, 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 2021 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 and 45195. NIPSCO concurrently prefiled its case-in-chief which included the direct testimony and exhibits of Nicole Woods, 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; and
- David Saffran, Generation Business Systems Administrator in the Operations Management Reporting Division.

On November 17, 2020, the NIPSCO Industrial Group ("Industrial Group") filed a Petition to Intervene. This petition was granted on December 1, 2020.[1]

The OUCC on December 21, 2020, prefiled the direct testimony and exhibits of the following:

- Michael D. Eckert, Assistant Director in the OUCC's Electric Division; and

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

- Gregory T. Guerrettaz, CPA, President of Financial Solutions Group, Inc.

NIPSCO filed no rebuttal testimony.

The Commission noticed this matter for an evidentiary hearing at 9:30 a.m. on January 7, 2021, in Hearing Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. A docket entry was issued on December 30, 2020, advising that due to the ongoing COVID-19 pandemic and with the agreement of all parties, the hearing would be conducted via WebEx and providing related participation information. NIPSCO, the OUCC, and the Industrial Group, by counsel, participated in the evidentiary hearing via WebEx video, and the testimony and exhibits of NIPSCO and the OUCC were admitted without objection. In addition, at the outset of the hearing, a motion filed on January 5, 2021, by the Industrial Group to withdraw the appearance of one of its attorneys was granted.

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

1. Commission Jurisdiction and Notice. Notice of the evidentiary hearing in this Cause was published as required by law. NIPSCO is a public utility as defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to NIPSCO's fuel cost 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 2020 averaged $0.024544 per kWh.

4. Requested Fuel Cost Charge. NIPSCO seeks to change its fuel cost adjustment from the current fuel cost credit of $0.000135 per kWh for bills rendered during the November 2020 through January 2021 billing cycle to a fuel cost charge of $0.001985 per kWh for bills rendered during the February through April 2021 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 $1,939,960 that was over-collected during July, August, and September 2020. NIPSCO's estimated monthly average cost of fuel to be recovered in this proceeding for the forecasted billing period of February through April 2021 is $25,945,060, and its estimated monthly average sales for that period are 880,844 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, 2020, were $57,453,411 below 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, 2020, were $20,398,326 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, 2020.

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 so as 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 58% of energy generated, and 42% 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 blend of Powder River Basin ("PRB") coal and Northern Appalachian ("NAPP") coal. He testified a blend of PRB coal and Illinois Basin ("ILB") coal is consumed in Unit 14; PRB coal is consumer in Unit 15, and ILB coal is consumed in Units 17 and 18 at the R.M. Schahfer Generating Station ("Schahfer").

A. Fuel Procurement. In discussing NIPSCO's coal procurement process, Mr. Wagner identified several factors NIPSCO considers when evaluating purchases for a specific generating unit, including the delivered cost, operational costs, cost of 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 the ability to comply with emission limits. He testified the reliability of the coal source and the reliability of coal transportation from that source are also critical factors NIPSCO considers.

Mr. Wagner testified that NIPSCO purchased coal during the reconciliation period under four term supply contracts. One of these contracts was with Arch Coal Sales Company for PRB coal, and two contracts were with Peabody COALSALES, LLC for ILB and PRB coal. The fourth was with CONSOL Pennsylvania Coal Company LLC for NAPP coal. Mr. Wagner confirmed that NIPSCO has no financial interest in the coal producers currently under contract.

Mr. Wagner testified that producers and customers are generally reluctant to execute long-term contracts with fixed prices without some type of market price adjustment mechanism. He opined that maintaining a price close to market is beneficial to both parties; therefore, a producer and customer may work together to establish an equitable price adjustment methodology. Mr. Wagner testified that, historically, market-based price adjustments in term supply agreements tend to reduce the buyer's cost of hedging since future prices are generally higher than spot and year-ahead prices. In addition to base price adjustments, quality price adjustments are used to maintain the underlying economics of the agreement on a dollar per million British thermal unit ("BTU") basis when the shipment quality varies from 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. Another contract had rates that are adjusted based on hourly power prices. 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 made no new commitments for spot or term coal purchases or coal transportation.

Mr. Wagner testified the delivered cost of coal consumed by NIPSCO's generating stations for the 12 months ending September 30, 2020, was $41.42 per ton or $2.096 per million BTU. The cost of coal consumed during the reconciliation period (July, August, and September 2020) was $42.33 per ton or $2.094 per million BTU. When compared to the second quarter of 2020, Mr. Wagner stated NIPSCO's delivered cost of coal consumed per ton decreased $0.33, and the cost was down $0.017 on a per million BTU basis. Mr. Wagner testified changes in the unit costs were largely due to lower railcar maintenance costs and lower PRB and ILB coal transportation rates that are adjusted to the hourly station locational marginal (power) prices ("LMPs"), which were soft during the reconciliation period.

Ms. Robles testified there have been no changes to NIPSCO's gas purchasing practices for NIPSCO's generation located off NIPSCO's gas distribution system (Sugar Creek Generating Station) during this period.

Ms. Robles testified that at this time, NIPSCO has not purchased natural gas to serve its generation fleet located on NIPSCO's gas distribution system under multiple-year contracts. Physical natural gas supplies are purchased on a spot basis when NIPSCO's gas-fired generation units are economical to run or need to run for operational purposes. The only future contracts entered into are, per Ms. Robles, financial hedges in accordance with NIPSCO's Electric Hedging Program. Ms. Robles testified 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.

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

OUCC witness Eckert testified that if coal decrement pricing is used in the future, NIPSCO should 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 coal decrement pricing is included in NIPSCO's forecast or has been used, NIPSCO shall file testimony, schedules, and workpapers in its future FAC proceedings addressing any need for and the reasonableness of any utilization of coal decrement pricing and shall provide inputs to its calculation of the coal price decrement consistent with the Commission's July 17, 2019 Order in Cause No. 38706 FAC 123.

C. Renewable Energy Credits ("RECs"). Ms. 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 Wind Power LLC ("Barton") on April 10, 2009, and from Buffalo Ridge I LLC ("Buffalo Ridge") on April 15, 2009. Consistent with the 43393 Order, NIPSCO is also crediting any off-system sales created by its wind PPAs with Barton and Buffalo Ridge. Ms. Robles testified that pursuant to the Commission's June 5, 2019 Order in Cause No. 45195 ("45195 Order"), and August 7, 2019 Order in Cause No. 45194 ("45194 Order"), NIPSCO anticipates beginning to receive power and seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Jordan Creek Wind Farm LLC ("Jordan Creek") starting December 1, 2020, and Rosewater Wind Generation LLC ("Rosewater") starting January 1, 2021. She stated the wind PPA adjustment for the forecast period is based on the average of actual wind PPA adjustment incurred for the 12-month period ended September 30, 2020. For the months of July, August, and September 2020, NIPSCO received 11,224 MWhs, 15,920 MWhs, and 13,859 MWhs, respectively.

Ms. Robles testified that each megawatt 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 NIPSCO receives RECs associated with the power it purchases from Barton and Buffalo Ridge and will soon receive RECs associated with the power it purchases from Jordan Creek and Rosewater. She stated these RECs are tracked by the Midwest Renewable Energy Tracking System ("M-RETS").[2] During this FAC period, she testified current vintage RECs were sold. The block size and proceeds from the sales were: (1) 26,764 with net proceeds of $28,443; (2) 14,343 with net proceeds of $15,523; (3) 9,765 with net proceeds of $14,281; (4) 10,356 with net proceeds of $15,145; and (5) 10,628 with net proceeds of $11,501.

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. 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 to its REC strategy.

Ms. Robles stated that NIPSCO now has 23 approved solar and wind customers with facilities registered in M-RETS, with nameplate capacities ranging between 0.05 MW and 2.0 MW. Solar and wind generation volumes are uploaded to M-RETS monthly. During this FAC period, Ms. Robles testified current vintage solar and wind FIT RECs were sold. The block size and sale proceeds were: (1) 9,706 with net proceeds of $18,927; (2) 7 with net proceeds of $11; and (3) 28 with net proceeds of $31. Ms. Robles stated NIPSCO has and will continue to pass the proceeds from the sale of FIT RECs back to customers through the "Purchased Power other than MISO" line item. She noted NIPSCO continues to have discussions with brokers and market participants to determine the best means of marketing the FIT RECs.

Ms. Robles testified that while NIPSCO did not enter into any third party energy transactions that are reflected in the estimated months of January, February, and March 2021, NIPSCO has been researching the possibility of entering into third party agreements to protect customers from market influences and entered into a third party energy transaction in October 2020 that will be reflected in the reconciliation period in NIPSCO's next FAC filing. She explained that the decision to engage in this type of transaction during October was made to address an increase in expected purchased power volumes as a result of the forced outages of Schahfer Units 14 and 15 and MISO's decision to require many planned outages to be rescheduled to the fall in recognition of COVID-19.

Ms. Robles testified that to address the Schahfer Units 14 and 15 outages, NIPSCO adjusted the hedging plan and entered into third party energy transactions to protect customers from market influences. She stated that due to these unexpected outages, the hedging plan was modified for August and September activity. Ms. Robles stated that based on the continued outages at Units 14 and 15, decisions were made, and are continuing to be made, on a month-to-month basis to determine any potential short on-peak positions that could be mitigated through an adjustment of the approved hedging plan. Ms. Robles noted these types of adjustments are consistent with NIPSCO's past practice of adjusting the hedging plan for material differences in generating unit availability. She explained that in the past, NIPSCO has recommended adjustments to the hedge plan approach and continues to evaluate factors that could impact the hedging

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

methodology. She stated that during the continued Schahfer Units 14 and 15 outages, NIPSCO will continue to adjust the hedging plan consistent with its past practices, and, if determined necessary, enter into third party energy transactions.

Ms. Robles testified that NIPSCO incorporated projected 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-month period ending September 30, 2020.

The Commission finds that 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, and 45195 and any other future renewable purchases.

D. Electric Hedging Program. Ms. Robles testified that in July 2020, NIPSCO purchased 61 gas contracts and 46 power contracts. In August 2020, NIPSCO purchased 63 gas contracts and 462 power contracts. In September 2020, NIPSCO purchased 65 gas contracts and 399 power contracts. Ms. Robles stated the execution of these contracts was consistent with NIPSCO's approved electric hedging plan through September 2020; however, as noted in FAC 128, NIPSCO discovered that for the month of July 2020, NIPSCO purchased six fewer gas contracts as a result of an error in the overall purchase schedule that affected that month. She stated the impact of this error to NIPSCO's customers was favorable. Ms. Robles testified NIPSCO revised the hedging plan in August and September due to the unplanned outages at Schahfer Units 14 and 15 and the movement of planned maintenance outages on other NIPSCO generating units. She stated these types of adjustments are consistent with NIPSCO's past practice of adjusting the hedging plan for material differences in generating unit availability.

Ms. Robles testified the impact of the hedges entered into for this FAC filing was a loss of $572,478 during the reconciliation period. She testified the net total impact of the hedging plan in this FAC reconciliation period, including broker and clearing exchange fees, was $584,576. Broker fees edged higher, representing 0.09% of the total value of the transactions occurring during this 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 the transactions all made in accordance with NIPSCO's approved Electric Hedging Plan.

Mr. Eckert testified that the OUCC reviewed NIPSCO's hedges and believes the hedging costs are reasonable. He testified that NIPSCO entered into 189 gas and 907 power contracts during July through September 2020.

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/Mbtu transportation charge, and then multiplied by the 12,500 BTU/kWh heat rate of a generic gas turbine. Ms. Robles stated that 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 which are excluded in accordance with the 43393, 45194, and 45195 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 period.

Ms. Robles testified that 236,844 MWhs of purchased power in July 2020 at an average purchased power cost of $33.83/MWh, 97,507 MWhs of purchased power in August 2020 at an average purchased power cost of $37.94/MWh, and 38,037 MWhs of purchased power in September 2020 at an average purchased power cost of $29.37/MWh were in excess of the Purchased Power Benchmark. As a point of comparison, she stated the monthly average of the Purchased Power Daily Benchmarks were $23.03, $27.77, and $24.63 for July, August, and September 2020, respectively. Ms. Robles testified the MWhs that exceeded the Benchmark in this reconciliation period can be attributed to the continued drop in natural gas prices which, effectively, lowered the average Purchased Power Benchmark for the reconciliation period by approximately 11% when compared to the same reconciliation period in 2019. While there were significant power purchases over the Benchmark, she stated these purchases 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 all purchases over the Benchmark in July, August, and September 2020 were determined to be recoverable. 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 that 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. 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 2020 was $3,410.917.

Ms. Robles testified the Real Time Non-Excessive Energy in July 2020 was $3,046,883 and $1,192,831 in September 2020. The primary drivers of these amounts were unit derates and forced outages that occurred after NIPSCO's units cleared in the Day Ahead market. Real Time Asset Energy in July 2020 was $1,486,955, primarily due to 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 testified the estimate for 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, 2020, where the high and low quarters are replaced with a three-year average of the same quarter. In this filing, NIPSCO included an estimate of MISO Components of Cost of Fuel in the amount of $348,138 per month.

9. Estimation of Fuel Cost. NIPSCO estimates its total average fuel costs for January, February, and March 2021 will be $25,945,060 on a monthly basis.

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

Mr. Wagner testified that as of October 29, 2020, NIPSCO's estimated market prices for delivery in the forecast period of January, February, and March 2021 were $12.10 per ton for PRB coal, $26.00 per ton for ILB coal, and $34.75 per ton for NAPP coal, excluding transportation costs. As of August 7, 2020, the spot market prices for shipments with September 2020 delivery were approximately $12.00 per ton for PRB coal, $25.70 per ton for ILB coal, and $34.50 per ton for NAPP coal, excluding transportation costs. Mr. Wagner testified that coal prices remained relatively low during this reconciliation period. He stated the Energy Information Administration anticipates United States coal production could fall 26% in 2020 when compared with 2019 production levels. Mr. Wagner testified that prices for NIPSCO's coal deliveries in the forecast period are fixed in most supply contracts, but if spot purchases are needed, NIPSCO anticipates coal supply to generally be available in the market and coal prices to be soft. Mr. Wagner stated the average spot market price of coal during the reconciliation period (and change from the previous reconciliation period) was $11.76 per ton (down $0.282) for PRB coal, $26.23 per ton (down $0.24) for ILB coal, and $34.44 per ton (up $1.64) for NAPP coal. He stated these prices do not include transportation costs, and given the relative illiquidity of coal markets, actual purchase prices may vary from published indices.

In identifying factors affecting the coal and transportation markets during the reconciliation period, Mr. Wagner testified that during the first half of 2020 coal consumption fell 29.7% when compared with the first half of 2019 and is on pace to decline by 23.3% for the year when compared to 2019. Meanwhile, he noted domestic electric coal inventories trended higher during the first half of 2020 and were roughly 5% above the five-year average due to soft demand for coal-fired generation attributed to a substantial drop in energy demand caused by the COVID-19 pandemic.

Mr. Wagner testified that during the first eight months of 2020, natural gas fired generation's share of the market was roughly 40.7%, and wind and solar comprised 11.8% of the electricity generated. He stated coal generation's share during this time was 18.3%, down from 23% on average during 2019 and down from the peak share of roughly 50% of the generation mix in the early 2000s. Mr. Wagner explained that in 2018, coal producers and railroads relied on strong international markets to offset the long-term decline in domestic demand, but unfortunately, annualized 2020 year-to-date demand from international markets for coal through September 2020 decreased nearly 29% when compared to 2018. He stated this continues to keep NAPP and ILB coal prices relatively low. Mr. Wagner testified this trend is anticipated to continue and will likely keep a ceiling on coal and transportation pricing and continue to financially strain coal suppliers and railroads' transportation businesses. He testified that NIPSCO's estimate for the cost of coal consumed for generation in the forecast period of January, February, and March 2021 is $42.29 per ton or $2.167 per million BTU.

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 and freeze conditioning (seasonal) costs, railcar leases and maintenance costs, transportation contract prices forecasted using estimates of future locational market prices ("LMPs") and natural gas prices, estimates of the impact of fuel surcharges on transportation rates using the current price of On-Highway Diesel Fuel ("HDF") and by estimating changes in the Association of American Railroad's All Inclusive Index Less Fuel ("AIILF"), 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 these to develop the forecast. Ms. Robles testified that NIPSCO completed its estimate for this FAC filing on November 11, 2020, using its production cost modeling system, PROMOD,[3] and made reasonable decisions under the circumstances then known.

Mr. Wagner testified that NIPSCO's coal transportation agreements have rates that are indexed to natural gas pricing or power prices and are also adjusted periodically by changes in the AIILF and HDF. One transportation agreement has rates indexed to generating unit hourly day-ahead LMPs, and another has significant rate discounts when natural gas prices are below threshold prices. Mr. Wagner 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. He stated HDF prices are roughly 30% lower when compared to the recent peak in October 2018 and are expected to increase during the forecast period, and, if this occurs, railroad fuel surcharges under one transportation agreement will increase. Mr. Wagner stated AIILF typically rises at a somewhat moderate rate.

Mr. Wagner testified that NIPSCO's rail carriers have been reliable, and NIPSCO expects stable delivery rates. Mr. Wagner stated the days of supply at the maximum burn measure for coal

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

inventory at Schahfer equaled approximately 57 days (down five days from the prior quarter) at the end of the reconciliation period. He testified a reduction in shipments resulted in lower inventory at Schahfer. 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 has 1,471 railcars used to support 10 unit trains (approximately 125 cars per unit train, plus 15% spares). He stated the typical spare railcar pool is roughly 8%; however, NIPSCO is in the process of collecting cars for return, and that has increased the spare railcar count. Mr. Wagner testified NIPSCO utilized roughly 57% of its railcar fleet during July and August 2020 and 33% during September 2020. He stated utilization was lower than anticipated due to unplanned outages that started in July on Schahfer Units 14 and 15 (roughly a four set impact). Shipments were suspended in mid-July due to these unplanned outages. In addition, Mr. Wagner explained that Schahfer started an extended outage on the Unit 17/18 dumper at the end of September to perform maintenance (a two to three set impact). These factors resulted in lower railcar utilization; consequently, NIPSCO had unanticipated underutilization of its railcar fleet during the reconciliation period. Notwithstanding, Mr. Wagner stated NIPSCO maximized the use of Bailly and Schahfer generating stations to store railcars during the reconciliation period to minimize storage costs. In addition, given the magnitude in the unanticipated decrease in deliveries, NIPSCO also stored three train sets at third party locations. Mr. Wagner stated that in general, fleet railcar maintenance costs fall when railcars are in storage resulting in a net reduction of cost to the customer. That being said, Mr. Wagner testified NIPSCO is currently working on the return of up to 452 railcars (roughly 3.6 sets) to lessors between now and the second quarter of 2021 to reduce capacity to match anticipated future requirements.

In addressing what improvements to the generating station heating sheds have been considered 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 from railcars. For Michigan City, NIPSCO continues to evaluate the effectiveness of the heating shed, with use of the heating shed at Michigan City ultimately at the discretion of station management and fuel handling supervisors. Mr. Wagner testified NIPSCO will continue to follow industry standards for frozen coal management. He stated 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 rail cars before they are loaded, while ILB and NAPP coal mines, at NIPSCO's direction, 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.

Mr. Guerrettaz testified that NIPSCO is working on its coal and transportation costs that will be passed through the current and future FACs. He noted NIPSCO updates the OUCC each FAC upon the most important items that change the costs and inventory. He stated the OUCC also reviews several of the cost savings plans NIPSCO has in place and the ongoing benefits. He testified that every quarter, NIPSCO provides updates during the audit that show the savings and benefits progress since the first of the year. Mr. Guerrettaz explained that this information provides a visualization of the reductions that have occurred and flowed through to ratepayers and should continue to occur in 2021.

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.

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 in this proceeding 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 $/kWh**</u>	<u>**Estimated Fuel Cost $/kWh**</u>	<u>**Estimating Error: Over (Under)**</u>
July	$0.027977	$0.024979	(10.72%)
August	$0.025991	$0.024586	(5.41%)
September	$0.019097	$0.024197	26.71%
Weighted Average Estimating Error			**0.26%**

Mr. Guerrettaz testified that nothing came to his attention indicating the projections NIPSCO used for fuel costs and power sales were unreasonable, considering a comparison of prior quarter actual and forecasted fuel costs and sales figures. He stated that as additional support for the reasonableness of the projections, NIPSCO provided updated gas and coal costs to verify the changes that had occurred since the forecast was prepared. He stated the costs had changed and were looked at during the virtual audit, but at this point, the OUCC believes the impact to be immaterial. Mr. Guerrettaz testified the OUCC reviews each component of the total cost of coal and the forecasted blend of coal by station and month.

Mr. Guerrettaz stated the OUCC went through the updated power, natural gas, coal, and transportation costs in detail and noted material fluctuations in all the prices. He testified that at this time, power prices and coal transportation costs are highly correlated to natural gas prices, and the OUCC has noticed material changes in purchased power and natural gas prices from week to week. Mr. Guerrettaz testified that NIPSCO provided National Oceanic and Atmospheric Administration data that showed the probability of NIPSCO's service area having a 50/50 chance of being colder or warmer than normal. Given the price swings, the impact of COVID-19 on energy demand, NIPSCO staff working from home, and the weather data NIPSCO supplied, Mr. Guerrettaz stated the OUCC has not requested NIPSCO to redo its forecast, but the OUCC will continue to monitor material changes and reserves the right to request NIPSCO to rerun its forecast in future periods. Mr. Guerrettaz testified the OUCC is recommending, however, that the forecast as calculated and presented by NIPSCO be used for this FAC.

Based on the evidence, including Mr. Guerrettaz's testimony upon the reasonableness of NIPSCO's fuel cost and power sales projections, the Commission finds NIPSCO's estimate of its prospective average fuel cost to be recovered during the February 2021 through April 2021 billing cycles is reasonable.

10. <u>Return Earned</u>. NIPSCO's evidence demonstrates that for the 12 months ending September 30, 2020, NIPSCO earned a jurisdictional return, including ECRM, FMCA, and TDSIC revenues, of $269,755,479. This exceeds NIPSCO's authorized amount of $264,164,433, which includes $251,542,939 approved in the applicable rate case, plus $12,621,494 of actual ECRM, FMCA, and TDSIC operating income during the 12 months ended September 30, 2020. This results in over-earnings of $5,591,046. While the earnings for the 12-month period ended September 30, 2020, exceed the annual authorized return, Ms. Woods testified the amount of over-earnings is more than offset by NIPSCO's bank of under-earnings, as reflected in the sum of the differentials calculation. She testified this calculation shows the sum of the differentials for the relevant period is ($272,707,014); therefore, under Ind. Code § 8-1-2-42.3, NIPSCO did not earn in excess of its authorized net operating income, and no refund is required.

Based on the evidence, the Commission finds that for the 12 months ended September 30, 2020, NIPSCO earned a return exceeding that authorized in its last base rate case, as appropriately adjusted, but NIPSCO's over-earnings were offset by NIPSCO's bank of under-earnings.

11. <u>OUCC Report</u>. 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, 2020, was computed in conformity with Ind. Code § 8-1-2-42 and the 45159 Order; (3) NIPSCO had jurisdictional net operating income for the 12 months ending September 30, 2020, greater than granted in its last base rate case, but based on the cumulative account balance of the earnings bank, no adjustment is needed; (4) the fuel cost adjustment for the quarter ending September 30, 2020, has been accurately applied; (5) the figures used in NIPSCO's application for a change in the FAC for the quarter ending September 30, 2020, were supported by NIPSCO's books, records, and source documentation; and (6) the OUCC recommends the fuel adjustment factor be approved as requested.

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 did not experience coal supply issues due to the financial struggles of the coal industry; (6) COVID-19, low consumer demand, low natural gas prices, and low purchase power prices may all impact NIPSCO's January through March 2021 projected coal burn; (7) NIPSCO's coal inventory at Schahfer has decreased since its last FAC filing to approximately 57 days, which is down five days from NIPSCO's prior FAC filing; (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 costs were reasonable; (11) NIPSCO provided information regarding its purchases and wind PPAs with Buffalo Ridge, Barton, and Jordan Creek; and (12) NIPSCO provided an update on the status of the Railroad Litigation.[4] OUCC witness Eckert further testified that a residential customer using 1,000 kWhs in December 2020 will pay $145.48 (excluding taxes), which consists of $134.91 in base charges set in NIPSCO's last approved rate case (Cause No. 45159), a fuel adjustment clause credit of $0.14, and $10.43 in non-FAC trackers.

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 $(0.000734) per kWh to be added to the estimated cost of fuel for bills rendered during the February 2021 through April 2021 billing cycles in the amount of $0.029455 per kWh. This results in a fuel cost adjustment factor of $0.001985 per kWh, after subtracting the cost of fuel in base rates and adjusting for applicable taxes. Ms. Woods testified a residential customer using 1,000 kWh per month will experience an increase of $2.12 on his or her electric bill from the currently approved factor.

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

14. Major Forced Outages. Consistent with past Commission Orders, Mr. Saffran sponsored Attachment 4-A describing each major forced outage NIPSCO's generating units experienced during the third quarter of 2020, including the length and cause of each major forced outage, the generating unit involved, and proposed solutions to prevent such outages from

[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").

reoccurring. For purposes of his presentation, a major forced outage is a unit forced outage lasting longer than three consecutive days.

15. **Status of Railroad Litigation.** In accordance with the Commission's Order in Cause No. 38706 FAC 125 ("FAC 125"), Ms. Woods testified the Railroad Litigation remains pending, and there have been no substantive developments and/or determinations. She stated that as of September 30, 2020, NIPSCO has not deferred any costs. The Commission finds NIPSCO shall continue to include in its FAC filings an update on the status of the Railroad Litigation as ordered in FAC 125.

16. **Confidential Information.** On November 16, 2020, 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 December 1, 2020 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 2021 through April 2021 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.

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 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.

7. 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.

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

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

APPROVED: JAN 20 2021

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

Mary M. Schneider Digitally signed by Mary M. Schneider
Date: 2021.01.20 10:10:47 -05'00'

Mary M. Schneider
Secretary of the Commission