STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7, 8-1-2-61 AND IND. CODE § 8-1-2.5-6 FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE IN OF RATES; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF REVISED COMMON AND ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (4) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF; AND (5) APPROVAL OF A NEW SERVICE STRUCTURE FOR INDUSTRIAL RATES.	)	**CAUSE NO. 45159**

PETITIONER'S MOTION FOR ADMINISTRATIVE NOTICE

Northern Indiana Public Service Company LLC ("NIPSCO"), by counsel, pursuant to 170 IAC 1-1.1-21, respectfully requests the Indiana Utility Regulatory Commission ("Commission") to take administrative notice of its April 29, 2019 Order in Cause No. 38706-FAC-122.

Petitioner notes that in accordance with 170 IAC 1-1.1-21 (j), "the commission may take administrative notice of relevant administrative rules, commission orders, or other documents previously filed with the commission." The attached document is a Commission Order related to the exclusion of non-fuel adjustment clause costs for purposes of Midcontinent Independent System Operator, Inc. offer prices for NIPSCO's coal units.

Respectfully submitted,

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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 MAY, JUNE, AND JULY 2019, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 44688, (2) RATEMAKING TREATMENT FOR THE COSTS INCURRED UNDER WHOLESALE PURCHASE AND SALE AGREEMENTS FOR WIND ENERGY APPROVED IN CAUSE NO. 43393 AND FOR THE COSTS OF RECOVERABLE INTERRUPTIBLE CREDITS, AND (3) AN UPDATED HEDGING PLAN, INCLUDING RECOVERY OF CERTAIN COSTS ASSOCIATED WITH THAT PLAN, PURSUANT TO IND. CODE § 8-1-2-42(d).	)	CAUSE NO. 38706 FAC 122 APPROVED: APR 29 2019

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
Carol Sparks Drake, Senior Administrative Law Judge

On February 15, 2019, 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 May, June, and July 2019 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. 44688; (2) ratemaking treatment for the costs incurred under wholesale purchase and sale agreements for wind energy approved in Cause No. 43393 and the costs of Recoverable Interruptible Credits, and (3) an updated hedging plan, including recovery of certain costs associated with that plan. NIPSCO concurrently prefiled the direct testimony and exhibits of NiSource Corporate Services Company employee Katherine A. Cherven, Manager of Regulatory, and the testimony and exhibits of the following NIPSCO employees:

- Benjamin J. Turner, Manager of Operations and Market Support;
- John A. Wagner, Manager, Fuel Supply;
- David Saffran, Generation Business Systems Administrator in the Operations Management Reporting Division; and
- Andrew S. Campbell, Director of Regulatory Support and Planning.

On February 18, 2019, Dennis Rackers, a residential homeowner in NIPSCO's service area, petitioned to intervene as a pro se person. His petition was granted on February 27, 2019, with the caveat that while he may represent his own interests pro se, he will be held to the standards in 170 IAC 1-1.1-7.

On February 26, 2019, the NIPSCO Industrial Group ("Industrial Group") filed a Petition to Intervene. This petition was granted on March 6, 2019.[1]

The Indiana Office of Utility Consumer Counselor ("OUCC") on March 22, 2019, prefiled the direct testimony and exhibits of the following:

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

Mr. Rackers prefiled testimony on March 22, 2019, but this filing was withdrawn due to containing information that all parties subsequently concurred should be treated as confidential information for purposes of this proceeding. NIPSCO on March 26, 2019, filed a motion for confidential treatment of this information, supported by the affidavit of its witness, Benjamin J. Turner. On March 27, 2019, confidential treatment was approved on a preliminary basis. Mr. Rackers prefiled redacted testimony on March 26, 2019, and confidential testimony on April 1, 2019. On March 27, 2019, he also prefiled an exhibit.

NIPSCO on March 29, 2019, filed rebuttal testimony for Mr. Turner and Mr. Wagner. NIPSCO also filed a correction on March 29, 2019, to Mr. Wagner's rebuttal testimony and a motion requesting administrative notice be taken of 59 Commission Orders. Copies of these Order were subsequently filed on April 2, 2019. On April 11, 2019, NIPSCO's motion requesting administrative notice was denied because the relevance of these Orders was not established consistent with 170 IAC 1-1.1-21.

The Commission held an evidentiary hearing at 8:30 a.m. on April 17, 2019, in Hearing Room 224 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the Industrial Group appeared by counsel and participated in the hearing. Mr. Rackers also appeared pro se and participated.

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

1. <u>Commission Jurisdiction and Notice</u>. 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. <u>NIPSCO's Characteristics</u>. NIPSCO is a limited liability company organized under the laws of the State of Indiana with its principal office in Merrillville, Indiana. NIPSCO renders electric public utility service in the State of 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. <u>Available Data on Actual Fuel Costs</u>. 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

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

case approved in the Commission's July 18, 2016 Order in Cause No. 44688 ("44688 Order") was \$0.031049 per kilowatt hour ("kWh"). NIPSCO's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity for the months of October, November, and December 2018 averaged \$0.029596 per kWh.

4. **Requested Fuel Cost Charge.** NIPSCO seeks to change its fuel cost adjustment from the current rate of \$0.002832 per kWh for bills rendered during the February, March, and April 2019 billing cycles to a fuel cost credit of \$0.001999 per kWh for bills rendered during the May through July 2019 billing cycles or until replaced by a different fuel cost adjustment approved in a subsequent filing.

The requested fuel cost adjustment includes \$899,417 that was under-collected during October, November, and December 2018. NIPSCO's estimated monthly average cost of fuel to be recovered in this proceeding for the forecast period of April, May, and June 2019 is \$35,343,212, and its estimated monthly average sales for that period are 1,303,004 MWh.

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 Ind. Code § 8-1-2-42.3, 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.
>
> (4) The utility's estimate[s] of its prospective average fuel costs for each such three (3) calendar months are reasonable after taking into consideration: (A) the actual fuel costs experienced by the utility during the latest three (3) calendar months for which actual fuel costs are available; and (B) the estimated fuel costs for the same latest three (3) calendar months for which actual fuel costs are available.

6. **Fuel Costs and Operating Expenses.** NIPSCO's Attachment 1-F shows fuel costs for the 12 months ending December 31, 2018, were \$64,481,255 below the amount approved in the Commission's 44688 Order. NIPSCO's Attachment 1-F also shows its total operating expenses, excluding fuel, for the 12 months ending December 31, 2018, were \$11,394,450 above the amount approved in the 44688 Order. The Commission finds there has been no increase in NIPSCO's actual

fuel costs for the 12 months ending December 31, 2018, which has been offset by actual decreases in other operating expenses.

7. <u>Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost</u>. 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 NIPSCO's primary fuel for generation of electric energy for the three months ended December 31, 2018, was coal (94%) with the remainder being natural gas (6%).

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 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 two term supply contracts with Arch Coal Sales Company (PRB coal) and Peabody COALSALES, LLC (ILB coal). During the reconciliation period NIPSCO also purchased one train of Northern Appalachian ("NAPP") coal under a spot supply agreement with Murray Energy. Mr. Wagner confirmed that NIPSCO has no financial interest in any coal producer 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, price adjustments in long-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 that one of NIPSCO's term coal contracts in effect during the reconciliation period has a firm price that increases each year as specified in the contract. The other contract has prices that are adjusted annually based on the average weekly indexed prices of that particular coal in the previous year. In addition, Mr. Wagner testified that all of NIPSCO's coal supply agreements adjust the price of coal based on a shipment's quality variances from contract specifications. NIPSCO made no new commitments during the reconciliation period for spot or term coal purchases.

Mr. Wagner testified the delivered cost of coal for NIPSCO for the 12 months ending December 31, 2018, was $46.19 per ton or $2.348 per million Btu. The delivered cost for coal shipments during the reconciliation period (October, November, and December 2018) was $44.30 per ton or $2.268 per million Btu. The delivered cost of coal for term contract coal shipments during the reconciliation period was $43.97 per ton or $2.261 per million Btu. The delivered cost for spot coal in the reconciliation period was $68.21 per ton or $2.607 per million Btu. When compared to shipments made during the third quarter of 2018, NIPSCO's delivered cost per ton decreased $0.44, and the cost was down $0.023 per million Btu. The average spot market price of coal during the reconciliation period, not including transportation costs (and change from the previous reconciliation period), was $12.42 per ton (up $0.03) for PRB coal, $39.28 per ton (up $2.42) for ILB coal, and $55.85 per ton (up $3.62) for NAPP coal.

In identifying what factors affected the market for coal and transportation during the reconciliation period, Mr. Wagner testified that strong demand for coal globally has increased United States coal exports to Europe and Asia. He stated demand for steam and metallurgical coal was robust during 2018, although this seems to be softening. This dynamic impacted Central Appalachian ("CAPP"), Illinois Basin ("ILB"), and NAPP coal markets throughout most of 2018. Exports of CAPP, ILB, and NAPP coal kept pricing firm through most of 2018. According to Mr. Wagner, this dynamic tends to increase transportation rates and may impact coal deliveries if railroad resources are shifted to serve stronger markets; however, he testified the biggest driver of coal demand during the reconciliation period was strong natural gas prices, especially in November 2018. This tended to increase locational marginal prices ("LMPs") and drove higher coal consumption. He testified that ILB spot coal prices increased roughly 7%, and NAPP prices increased roughly 10% when compared to August prices. CAPP prices led the increases at roughly 16% driven by natural gas and supported by strong export demand that Mr. Wagner stated continued to be at the top of the five-year range. Mr. Wagner testified that domestic coal inventories are 27% lower than November 2017 levels, and while such lower inventory levels might have been a concern in prior years, given reduced coal consumption rates and the continued retirement of coal-fired generating units, this trend is likely to continue. Mr. Wagner stated that NIPSCO's cost of coal consumed for generation in the forecast period is estimated to be $41.82 per ton or $2.131 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, transportation contract prices forecasted using estimates of future 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"), estimated changes in the Association of American Railroad's All Inclusive Index Less Fuel ("AIILF"), and estimates of future coal market prices. He testified that for Michigan City, a blend of PRB coal and NAPP coal is consumed. A blend of PRB coal and ILB coal is consumed in Unit 14, and PRB coal is consumed in Unit 15, with ILB coal consumed in Units 17 and 18 at Schahfer.

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 fell roughly eight percent from the peak in October 2018 and are projected to increase modestly during the forecast period. Railroad fuel surcharges under one transportation agreement will increase moderately. Mr. Wagner stated AIILF typically rises at a somewhat moderate rate.

Mr. Wagner testified that NIPSCO does not anticipate any issues in securing coal since market pricing is expected to remain somewhat flat, and coal supply should be adequate, but higher coal demand and relatively high cycle times to Schahfer have kept pressure on coal delivery logistics. Specifically, PRB coal consumption at Schahfer was up 139% in 2018 when compared to 2017. ILB shipments to Schahfer were relatively flat year-over-year, but these were still robust. Mr. Wagner testified that one of NIPSCO's rail carriers has struggled to provide consistent service at Schahfer, but this performance appears to be improving. In addition, NIPSCO leased another unit train (120 cars) to support anticipated 2019 demand; therefore, NIPSCO expects coal deliveries will meet demand during the forecast period. Mr. Wagner testified that days of supply at the maximum burn measure for coal inventory at Schahfer equaled approximately 26 days (down 11 days from the prior quarter) at the end of the reconciliation period while Michigan City's coal inventories were close to target levels. Mr. Wagner stated NIPSCO has made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible.

Mr. Turner testified that NIPSCO does not purchase natural gas to serve its generation fleet 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 Mr. Turner, financial hedges in accordance with NIPSCO's Electric Hedging Program. Mr. Turner testified that NIPSCO has made every reasonable effort to purchase natural gas so as to provide electricity at the lowest reasonable price.

Mr. Rackers asserted there was no clear testimony that NIPSCO made every reasonable effort to generate at the lowest cost reasonably possible. He stated that although Mr. Turner testified that NIPSCO made every effort to generate *or* purchase power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible, Mr. Turner did not state that NIPSCO had both generated *and* purchased power at the lowest cost reasonably possible. Mr. Rackers opined that NIPSCO needs to explain its efforts to reduce the cost of electric generation for its customers and, at a minimum, NIPSCO should include: (i) its efforts, if any, to improve heat rates for its generating units, (ii) its efforts, if any, to identify and utilize the most cost-effective type of coal for its boilers, (iii) reduce the minimum load rating or output of its coal units so the generation can be turned down during times of low demand when the fuel costs can be greater than Midcontinent Independent System Operator, Inc. ("MISO") market prices, (iv) remove non-fuel cost adjustment ("FAC") costs from its offers into MISO's energy market so NIPSCO's generation is more likely to clear the market to run, and (v) provide a quarterly report of the benefit derived from NIPSCO's generation.

Mr. Rackers recommended the Commission enforce what he believes is the plain meaning of Ind. Code § 8-1-2-42(d)(1) and require NIPSCO in this and all future FAC proceedings to submit testimony and evidence sufficient to demonstrate that it has made every reasonable effort to generate power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible (to include items (i) through (v) above). He also recommended NIPSCO remove non-FAC costs from NIPSCO offers into the MISO energy market. Mr. Rackers testified that inclusion of certain non-FAC costs improperly increases NIPSCO's offer prices and makes NIPSCO's offered generation less likely to clear the market to run.

Mr. Rackers concluded that NIPSCO electric customers are currently denied the benefits of price competition and access to retail choice. He stated the Commission could engender some measure of competition and increase NIPSCO accountability by requiring NIPSCO to compare the fuel cost of its own generation to the cost of power it purchases from MISO's wholesale energy market for resale to its electric customers.

In his rebuttal testimony, Mr. Turner quoted Ind. Code § 8-1-2-42(d)(1), which in relevant part provides: "(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[.]" He testified that he understands this provision requires two findings by the

Commission: (1) that 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" and (2) that NIPSCO has "made every reasonable effort to . . . generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible[.]" He testified the second finding can be satisfied by any one of three showings: that NIPSCO has (a) generated power or (b) purchased power or (c) generated and purchased power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. Mr. Turner opined that NIPSCO's case-in-chief sets forth how NIPSCO satisfies the requirements of Ind. Code § 8-1-2-42 generally and Section 42(d)(1) specifically. Mr. Turner went on to testify that NIPSCO has "made every reasonable effort to . . . generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible[.]" Petitioner's Exhibit No. 2-R at p. 6. Mr. Turner testified that Ind. Code § 8-1-2-42(d)(1) does not require a utility to demonstrate that it both generated and purchased power at the lowest cost reasonably possible, and Mr. Rackers' assertions otherwise misread the statute.

Mr. Turner further testified that Ind. Code § 8-1-2-42 does not require NIPSCO to make its generation the most economic source of power. Rather, NIPSCO is charged with making every reasonable effort to "generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible[.]" Petitioner's Exhibit No. 2-R at pp. 7-8. He stated NIPSCO strives to ensure that it serves its customers' needs at the lowest reasonable cost possible, notwithstanding whether that is through NIPSCO-owned generation or purchases through the wholesale (i.e., MISO) market.

With respect to the five categories of information Mr. Rackers recommended including in NIPSCO's FAC filings, Mr. Turner testified that this portion of Mr. Rackers' testimony shows that Mr. Rackers believes the scope of this FAC proceeding is much broader than it truly is. Mr. Turner noted that during his employment at NIPSCO dating back to 2005, the scope of FAC proceedings has generally been limited to reviewing the cost to acquire fuel for a utility's generation and the cost of power that is purchased to serve the utility's customers. He also testified that NIPSCO already provides the OUCC with a majority of the information Mr. Rackers requested in its quarterly FAC proceedings or similar information as audit support. Mr. Turner explained that NIPSCO provides testimony and schedules about its projected cost to purchase power and its expected generation utilization. In addition, NIPSCO provides detailed audit support of projected coal costs, projected power and gas prices, projected average unit heat rates, projected unit planned maintenance outages, etc. as it pertains to each FAC proceeding. Also, at the onsite audit conducted every quarter, the OUCC is provided an opportunity to discuss and request documents regarding all matters that are relevant to NIPSCO's FAC proceeding. This often includes information related to the cost of serving NIPSCO's customers by NIPSCO-owned generation and through purchases from the MISO market and the relationship between such costs. He also testified that each FAC cycle, NIPSCO provides a reconciliation of a prior three-month FAC period.

Mr. Turner stated the stakeholders involved in NIPSCO's FAC process have been satisfied with the information NIPSCO has provided in these proceedings, as has the Commission. He testified that NIPSCO is, however, willing to commit to hold discussions with interested stakeholders to see if a consensus can be reached upon whether additional information would be helpful in future FAC proceedings. He recommended these discussions include the OUCC, the Industrial Group, and other participants represented by counsel who have actively appeared in NIPSCO's FAC proceedings over the last five years.

Mr. Turner testified that he did not agree with the cost savings analysis in Mr. Rackers' Exhibit No. 1, stating it is assumption laden and problematic for several reasons, including, but not limited to, it: (1) assumes NIPSCO's coal-fired generation was available and ignores generation outages and derates; (2) presumes MISO would have dispatched NIPSCO's units differently; (3) ignores the existence of transmission constraints on the system; and (4) assumes LMPs in the market would have been unchanged despite a difference in NIPSCO's generation offers and overall resource mix within the MISO market.

In his rebuttal testimony, Mr. Turner also testified that NIPSCO has a fundamental disagreement with Mr. Rackers' position that only "FAC costs" should be included in NIPSCO's offers into the MISO energy market. He stated there are multiple approaches that can be utilized by a utility to construct its offers into the MISO market, and in general, all costs that contribute to the variable cost of production of NIPSCO's generating units should be included in NIPSCO's offers into the MISO energy market, irrespective of whether those costs are recovered in an FAC proceeding, in some other tracker mechanism, or in base rates. Mr. Turner testified that this is intended to align the components of NIPSCO's offers into the MISO market with the total variable costs of NIPSCO's generation resources, regardless of how NIPSCO recovers those costs. He also explained that the issue of NIPSCO's offer strategy into the MISO energy market has been audited in prior FAC cycles. Citing Attachment 2-R-C to his rebuttal testimony, Mr. Turner stated that the distinction between the costs that are recovered through the FAC process under Ind. Code § 8-1-2-42 and the costs that are recovered through NIPSCO's base rates is not relevant to the question of what costs are appropriately included in NIPSCO's offers of its generation into the MISO energy market.

Mr. Turner disagreed with Mr. Rackers' statement that inclusion of certain non-FAC costs improperly increases NIPSCO's offer prices and, therefore, makes NIPSCO's offered generation less likely to clear the market to run. He testified that if NIPSCO were to follow Mr. Rackers' suggestion and remove certain non-FAC costs from its offers into the MISO energy market, this would artificially lower the variable cost of NIPSCO's generation and could cause the units to be uneconomically dispatched by MISO, resulting in higher total costs to serve customers. This would contradict NIPSCO's mandate under Ind. Code § 8-1-2-42 to make every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to NIPSCO's retail customers at the lowest fuel cost reasonably possible.

Mr. Rackers testified that NIPSCO's inclusion of certain non-FAC costs in its offers to MISO obscures the cost advantage of its steam generation. At the hearing, however, Mr. Rackers acknowledged that his Exhibit No. 1 supporting this premise is based on a presumption that all the megawatt hours ("MWhs") of energy NIPSCO purchased through the MISO market could have and would have been produced by NIPSCO's steam generation units. He further testified that his analysis presumed the cost of producing energy from NIPSCO's steam generation would have remained the same, despite the increase in NIPSCO steam generation. Mr. Rackers stated he was aware NIPSCO provided a list of outages for NIPSCO-owned generation for 2018 with Mr. Saffran's testimony in this matter, but this information about NIPSCO generation outages was not taken into account when developing his Exhibit No. 1.

At the hearing, Mr. Turner testified that Ind. Code § 8-1-2-42(d)(1) requires two findings by the Commission, and the second, related to the generation or purchase of power or both, can be satisfied by any one of three showings: that NIPSCO has (a) generated power or (b) purchased power or (c) generated and purchased power so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible.[2] Regarding the statement in his rebuttal testimony indicating NIPSCO is willing to hold discussions with interested stakeholders to see whether additional information would be helpful in future FAC proceedings, Mr. Turner explained his understanding that certain confidential and/or highly confidential matters relevant to NIPSCO's FAC proceedings are discussed in such stakeholder meetings, which makes participation by anyone without legal representation potentially problematic.

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. We also find NIPSCO has demonstrated that its current offer strategy of its generation units into the MISO energy market is reasonable. Conversely, we are not persuaded that Mr. Rackers established NIPSCO has included inappropriate components in its offers to MISO or has been imprudent with respect to its generation decision-making. Based on the information provided in this proceeding, we find NIPSCO has adequately demonstrated that it "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[.]" Ind. Code § 8-1-2-42(d)(1).

Consistent with NIPSCO's offer to hold additional stakeholder discussions in its next FAC proceeding (i.e., FAC 123), NIPSCO is directed to discuss with all participants in that FAC proceeding whether additional information would be helpful in future FAC proceedings and, if so, identify such additional information. In NIPSCO's subsequent FAC proceeding (i.e., FAC 124), NIPSCO is directed to report to the Commission the outcome of these discussions.

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 that NIPSCO removed all coal and associated coal transportation decrements during the third quarter of 2018. He stated NIPSCO only decrements its offers when such a strategy benefits its electric customers. NIPSCO believes the use of coal and transportation decrements assists in ensuring reliable energy supply at the lowest reasonable cost. Mr. Wagner testified that NIPSCO evaluates the use of decrements to determine if their use benefits customers and currently does not anticipate the need to decrement its MISO offer prices for the foreseeable future; however, decrements may again be used if market dynamics and contractual obligations indicate doing so is in NIPSCO's customers' best interest. Mr. Wagner testified that cost decrements are not something a utility should seek to avoid. Rather, a utility that wants to use the least expensive energy source reasonably possible for its customers should, he testified, account for all incremental costs. He testified that avoided costs associated with the failure to perform NIPSCO's obligations under any supply agreement must be reflected in a unit's offer to reflect the true economic cost of generating. From his perspective, reflecting these avoided cost savings is necessary to maximize customer value in any highly-competitive, volatile market, and an adjustment that lowers the price of a unit offer is no different than a utility's decision to take a unit offline for maintenance when it minimizes cost or offer its units as must run for reliability. Mr. Wagner testified these are all tools used proactively to minimize fuel and purchased power costs and maximize reliability and customer value.

[2] During the hearing, Mr. Turner clarified that under his interpretation, generation issues—such as heat rates and whether imprudent operation of a generating plant necessitated the need for purchased power—are appropriate considerations for FAC proceedings.

Mr. Turner testified that decrement pricing has not been included in NIPSCO's forecast for purposes of this fuel adjustment proceeding because NIPSCO does not anticipate a need to utilize decrement pricing in the forecast period.

OUCC witness Eckert recognized that NIPSCO has stopped using coal decrement pricing, but he 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 coal decrement pricing to end, as well as provide inputs to its calculation of the coal price decrement.

The Commission finds, based on the evidence, that NIPSCO has stopped using coal decrement pricing, and decrement pricing is not included in NIPSCO's forecast for purposes of this FAC proceeding. We further find that in future FAC proceedings, if coal decrement pricing is included in NIPSCO's forecast or has been used, NIPSCO shall file testimony, schedules, and workpapers 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 information OUCC witness Eckert requested.

C. Renewable Energy Credits ("RECs"). Mr. Turner provided an update on NIPSCO's treatment of RECs associated with its energy purchases under wind purchased power agreements. He 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 Farm on April 10, 2009, and from Buffalo Ridge Wind Farm on April 15, 2009. NIPSCO is also crediting any off-system sales created by its wind purchased power agreements ("PPAs") with Barton and Buffalo Ridge. In addition, NIPSCO is projecting the wind PPA adjustment for the forecast period based on the average of actual wind PPA adjustment incurred for the twelve month period ended December 31, 2018. For the months of October, November, and December 2018, NIPSCO received 23,848 MWhs, 23,750 MWhs, and 23,639 MWhs, respectively.

Mr. Turner testified that each megawatt of power generated from a qualified resource can be awarded a REC, and because no national standard currently exists, each jurisdiction has set its own regulations upon how to qualify and account for RECs. Mr. Turner testified that NIPSCO receives RECs associated with the power it purchases from the Barton and Buffalo Ridge Wind Farms which qualify under a coalition of midwestern states, not including Indiana, and are tracked by the Midwest Renewable Energy Tracking System ("M-RETS").[3] During this FAC period, Mr. Turner testified a block of current vintage RECs was sold. The block size and proceeds from the sale were: 67,757 with net proceeds of $31,168; 17,921 with net proceeds of $13,262; and 25 with net proceeds of $125.

Mr. Turner testified that NIPSCO has and 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 Mr. Turner, 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 RECs' strategy.

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

Mr. Turner stated that NIPSCO now has 22 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, Mr. Turner testified a block of 1,505 current vintage solar FIT RECs was sold with net proceeds of $2,258. Mr. Turner stated NIPSCO continues to have discussions with brokers and market participants to determine the best means of marketing the FIT RECs.

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 No. 43393 and any other future renewable purchases.

D. Electric Hedging Program. Mr. Turner testified that in October 2018, NIPSCO purchased 7 gas contracts and 1,288 power contracts. In November 2018, NIPSCO purchased 30 gas contracts and 1,344 power contracts. In December 2018, NIPSCO purchased 65 gas contracts and 260 power contracts. Mr. Turner stated the execution of these contracts is consistent with NIPSCO's approved electric hedging plans. The impact of the hedges entered into for the Electric Hedging Program for this FAC filing was a gain of $2,626,152 during the reconciliation period. The net total impact of the Electric Hedging Program in this reconciliation period, including broker and clearing exchange fees, was $2,607,053. Broker fees represented 0.06% of the total value of the transactions occurring during the reconciliation period. Mr. Turner 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 costs, with the transactions all made in accordance with NIPSCO's approved Electric Hedging Program.

Mr. Eckert testified that the OUCC reviewed NIPSCO's hedges and believes the hedging costs are reasonable. He affirmed that NIPSCO entered into 102 gas and 2,892 power contracts during October through December 2018.

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. Mr. Turner 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"). He testified that in the 43526 Order, the Commission approved a Benchmark triggering mechanism to judge the reasonableness of purchased power costs. He 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 Order. 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.

Mr. Turner testified that 56,474 MWhs of purchased power in October 2018, 16,765 MWhs of purchased power in November 2018, and 2,627 MWhs of purchased power in December 2018 were in excess of the Purchased Power Daily Benchmarks. He testified that in accordance with the procedures outlined in the 43526 Order, NIPSCO determined none of the purchases over the Purchased Power Benchmark are non-recoverable because 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.

Mr. Eckert testified that Mr. Turner's testimony and workpapers accurately reflect the methodology the Commission approved in the 43526 Order regarding purchased power over the Benchmark. Mr. Eckert stated that he created a working model of Mr. Turner's purchased power over the Benchmark calculations, and he agrees with Mr. Turner's purchased power over the Benchmark calculations.

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

Based on the evidence, the Commission further finds that NIPSCO has made every reasonable effort to acquire fuel and generate or purchase power 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 charges associated with the MISO Day 2 energy market in accordance with the Commission's Orders in Cause Nos. 42685, 43426, and 43665. The total MISO Components of Cost of Fuel included in the actual cost of fuel for October through December 2018 was $2,042,381.

Mr. Turner testified that in October, November, and December 2018, Real Time Non-Excessive Energy was $2,500,481, $1,746,323, and $2,301,209 respectively. The primary drivers of these figures were unit derates and forced outages that occurred after NIPSCO's units cleared in the Day Ahead ("DA") market. He 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.

Mr. Turner testified that under the agreement the parties reached in Cause No. 38706 FAC 104, 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 December 31, 2018, 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 $1,439,348 per month.

9. Interruptible Credits. Mr. Turner testified NIPSCO's Interruptible Industrial Service Rider provides for credits to be paid to certain industrial customers that agree to interrupt their service if certain criteria are met. He testified that during October through December 2018, NIPSCO initiated interruptions under Rider 775 on five separate days for a total of 85 hours under Option C.

The evidence shows NIPSCO paid a total of $13,041,603 in interruptible credits for the reconciliation period. Pursuant to the Commission's July 18, 2016 Order in Cause No. 44688, NIPSCO is authorized to recover 25 percent of that total, or $3,260,401, through the FAC for bills rendered during the May through July 2019 billing cycles.

10. Estimation of Fuel Cost. NIPSCO estimates its total average fuel costs for April, May, and June 2019 will be $35,343,212 on a monthly basis.

Mr. Wagner testified that as of February 7, 2019, NIPSCO's estimated market prices for coal shipped in the forecast period of April through June 2019 were $12.30 per ton for PRB coal, $37.50 per ton for ILB coal, and $54.75 per ton for NAPP coal, excluding transportation costs. The average spot market prices for delivery during the reconciliation period were $12.42 per ton (up $0.03) for PRB coal, $39.28 per ton (up $2.42) for ILB coal, and $55.85 per ton (up $3.62) for NAPP coal, excluding transportation costs. As of February 7, 2019, the spot market prices for shipments in March 2019 were $12.40 per ton for PRB coal, $38.50 per ton for ILB coal, and $55.25 per ton for NAPP coal, excluding transportation costs. Mr. Wagner testified that if spot purchases are needed, NIPSCO anticipates coal supply to generally be available and market prices in the United States to be relatively stable.

Mr. Wagner explained that in developing the forecast period estimate, NIPSCO's fuel supply group incorporates coal contract prices inclusive of any adjustments specified in the agreement, transportation contract prices, estimates of the impact of fuel surcharges on transportation rates using the current price of HDF and estimating changes in the AIILF, and estimates of future coal market prices. In addition, the fuel supply group provides a forecast of beginning inventory values in dollars and quantities in tons for each generating station. These assumptions are provided to NIPSCO's energy supply and optimization group who use the assumptions to develop the forecast. Mr. Turner testified that NIPSCO completed its estimate for this FAC filing on February 7, 2019, using its production cost modeling system PROMOD[4] and made reasonable decisions under the circumstances then known.

Mr. Wagner testified the prices for NIPSCO's coal deliveries in the quarterly forecast period are generally fixed in supply contracts. The coal producers are obligated to perform under existing contracts. If spot purchases are needed, he stated NIPSCO anticipates coal supply will generally be available, and market prices are expected to be relatively stable. 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 locational marginal prices, 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 that HDF prices fell roughly eight percent from the peak in October. HDF prices are projected to increase modestly during the forecast period, and railroad fuel surcharges under one transportation agreement will increase moderately. He stated the AIILF typically rises at a somewhat moderate rate. Mr. Wagner testified that rail carrier performance with one of NIPSCO's rail carriers continued to limit deliveries to Schahfer during the reconciliation period. Cycle times (the time it takes for a unit train to make a round trip) for NIPSCO coal movements were relatively high, and NIPSCO is working closely with that railroad and station personnel to improve railroad and station unloading performance. As of late, Mr. Wagner stated unloading and railroad performance have improved, and NIPSCO expects cycle times to continue improving modestly.

Mr. Wagner testified that NIPSCO has 1,351 railcars used to support 10 unit trains (approximately 125 cars per unit train, plus 8% spares needed to support maintenance of the fleet).

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

During the reconciliation period, NIPSCO utilized 100% of its railcar fleet. Consumption at Schahfer remained robust, and relatively longer cycle times to that station maximized the utilization of NIPSCO's fleet. In addition, a culvert replacement at Schahfer required suspension of deliveries for three weeks; consequently, inventories had to be quickly rebuilt. Mr. Wagner testified that NIPSCO leased a train set from another utility for three trips and leased one additional set for one year with the anticipation that 11 sets will be required for a large portion of 2019. Mr. Wagner stated this will increase NIPSCO's fleet size to 1,471 railcars.

Mr. Wagner testified that NIPSCO had no surplus train capacity at the end of the reconciliation period. Notwithstanding this status, to minimize storage costs, idle unit trains are typically stored at Schahfer or at Bailly, whenever possible, before trains are stored at third party locations. He stated this practice has minimized the cost of storage, but he testified storage cost is only one of many factors considered when determining the size of NIPSCO's unit train fleet. Mr. Wagner testified that a key consideration is the cost of unit train capacity. Specifically, he testified the market for railcars over the last three years has been extremely soft, at an all-time low, and this has driven the cost to carry surplus capacity down substantially. Mr. Wagner noted, however, that market lease rates in the reconciliation period spiked as short-term coal demand increased as natural gas prices rose sharply. According to Mr. Wagner, even with higher lease rates, the reliability surplus capacity affords outweighs the cost of carrying this capacity. In addition, modest surplus capacity is prudent because it protects against unplanned unloading outages, unforeseen changes in consumption, and cycle times. He opined that it is not prudent to minimize the number of unit trains given the unpredictability of demand, delivery rates, and the time required to lease additional railcars. Mr. Wagner explained that once the need for additional railcars is identified, it can take several months to solicit the market, evaluate bids, award the business, execute contracts, receive authorization from the railroads to operate the sets on their systems, and have sets moved into operation. From Mr. Wagner's perspective it is not prudent practice to rely on the market for trip leases or spare railcar capacity given the length of time required to lease new unit trains and place them into service. Mr. Wagner testified that if NIPSCO had not carried modest surplus railcar capacity during the first four months of 2018, there is a high probability coal generation would have been curtailed during the latter half of 2018.

Mr. Wagner also discussed heating shed improvements and freeze treatment. He stated the Schahfer heating sheds are not used because they are not effective. According to Mr. Wagner, an evaluation of the Michigan City heating shed was made in 2018, and the costs associated with the recommended improvements were prohibitive relative to the estimated benefits; therefore, NIPSCO chose to repair a number of heating elements prior to the 2018-2019 winter and will operate the heating sheds in their original configuration as needed. Mr. Wagner testified that heating sheds are marginally effective in moderate winter conditions. In severe weather conditions (wet periods followed by extremely low temperatures) he stated heating sheds can cause huge blocks of coal weighing several tons to loosen and fall. This condition restricts coal flow through the unloading hoppers and/or can cause significant damage to unloading equipment. Mr. Wagner opined that this creates an unsafe condition and typically causes significant unloading delays. To mitigate the problems caused by large blocks of coal, Mr. Wagner testified additional capital improvements would be required to install frozen coal crackers to break up these blocks. He stated this further increases cost without a significant increase in benefits. Mr. Wagner testified that given the risks and the limited benefits associated with heating shed use, other utilities have discontinued their use because they are not effective in severe winter conditions and can create safety concerns. He stated most utilities rely heavily on the use of freeze conditioning applied at the mines.

Mr. Wagner testified that with respect to freeze conditioning, NIPSCO uses best practices. For PRB coal, NIPSCO's sources apply side release to the empty railcars before these are loaded. ILB coal mines also apply side release and full body freeze treatment. He stated NIPSCO directs the application rates of full body treatments depending on the severity of the weather because the efficacy of freeze treatments can be substantially diminished in severe conditions, even at maximum application rates.

Mr. Guerrettaz testified that NIPSCO continues to work on the pricing of coal and transportation contracts to either adjust costs downward or keep further increases from occurring. He stated the OUCC has been analyzing and reviewing NIPSCO's frozen coal issues and freeze treatment processes since the "Polar Vortex" in 2013/2014 when NIPSCO's freeze treatment costs went up. Mr. Guerrettaz testified that since then, coal freeze treatment costs have fallen, but sporadic increases still occur due to extremely cold weather. He testified that NIPSCO incurs more freeze treatment costs and frozen coal due to its close proximity to Lake Michigan and its reliance on western coal. Mr. Guerrettaz testified that western coal is in the railcar for a longer period of time due to the distance between the mine and NIPSCO's facilities. Mr. Guerrettaz testified that the OUCC has also been reviewing the thawing sheds NIPSCO and other utilities use as part of an ongoing review of freeze treatment processes and frozen coal. He shared a data response from NIPSCO addressing use of the thawing shed at Michigan City and related upcoming maintenance work.

Mr. Rackers testified that although NIPSCO reported freeze-conditioning costs for the months of November and December 2018, it did not incur lightweight charges attributable to frozen-coal carryback in rail cars during those months. He stated that NIPSCO's lightweight charges can be eliminated and its freeze conditioning costs reduced with reasonable efforts to operate rail car heating sheds in conjunction with the rotary car dumping operations at its coal-fired generating stations.

In his rebuttal testimony, Mr. Wagner testified that NIPSCO's freeze-conditioning charges have averaged a little over $475,000 per year between the winter of 2014 and 2018, although costs can vary based on the severity of the weather, as shown in Attachment 3-R-A to his rebuttal testimony. He stated this an extremely small portion of NIPSCO's overall FAC costs (roughly 0.1%). As shown in Attachment 3-R-B to his rebuttal testimony, he also explained that, over the past four winters, light weight or "carry back"[5] charges have averaged about $120,000 per winter season. He testified that NIPSCO makes every commercially reasonable effort to minimize the costs associated with fuel, including costs associated with frozen coal, but that totally eliminating lightweight charges and reducing freeze conditioning costs through use of a heating shed is incorrect and ignores the potential unloading complications associated with heating sheds and the potential damage to aluminum rail cars. Mr. Wagner also testified that lightweight charges cannot be completely eliminated and that this is especially true for northern and midwestern utilities like NIPSCO that operate in colder climates. He stated the level of NIPSCO costs associated with frozen coal issues demonstrates NIPSCO's frozen coal practices are reasonable and effective.

At the hearing, Mr. Wagner testified that NIPSCO does not currently utilize heating sheds at Schahfer but is utilizing the heating sheds at Michigan City on a test basis to determine if doing so could help with issues related to frozen coal, including reducing lightweight or "carryback" charges.

[5] "Lightweight charges" is the term used in the coal industry to describe the costs associated with sending rail cars back to the coal supplier with some coal remaining in the cars (i.e., "carryback"), because it is frozen to the rail car reducing the amount of coal that can be loaded in the rail car.

He explained that NIPSCO's annual expenditure on fuel for its coal-fired generating stations is approximately $220 million and, as reflected on Attachment 3-R-B to his rebuttal testimony, annual costs associated with lightweight charges are approximately $120,000 per winter season.

Mr. Guerrettaz testified that based on his onsite audit and review of detailed work papers NIPSCO provided, the OUCC believes the forecast appears to be reasonable and reflects the best estimate of likely cost and generation for the forecasted period.

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

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

In the Commission's January 23, 2019 Order in Cause No. 38706 FAC 118 (at p. 12) and in Cause No. 38706 FAC 121, NIPSCO was ordered to include in its FAC filings covering winter months information about improvements to the generating station heating sheds and any freeze treatment used. The Commission finds NIPSCO provided the requisite testimony and information in this proceeding regarding improvements to the generating station heating sheds and freeze treatments, as ordered in Cause Nos. 38706 FAC 118 and 38706 FAC 121, and NIPSCO should continue to provide in its quarterly FAC filings covering winter months information about improvements to the generating station heating sheds and any freeze treatment used.

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

Month	Actual Fuel Cost $/kWh	Estimated Fuel Cost $/kWh	Estimating Error: Over (Under)
October	$0.030741	$0.030702	(0.13) %
November	$0.029687	$0.030235	1.85 %
December	$0.028404	$0.028439	0.12 %
Weighted Average Estimating Error			**0.55 %**

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 forecast 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, providing an entire month-by-month forecasted coal cost for each component of the cost of coal as part of its audit package. Mr. Guerrettaz testified that the OUCC reviews each component of the total cost of coal and the forecasted blend of coal by station and month. Based on its onsite FAC audit and review of the detailed work papers NIPSCO provided, the OUCC believes the forecast is reasonable and reflects the best estimate of likely costs and generation for the forecasted period.

Based on the evidence presented, including Mr. Guerrettaz's testimony upon the reasonableness of NIPSCO's fuel cost and power sales projections, the Commission finds NIPSCO's estimate of its prospective average fuel cost to be recovered during the May, June, and July 2019 billing cycles is reasonable.

11. <u>Return Earned</u>. NIPSCO's evidence demonstrates that for the 12 months ending December 31, 2018, NIPSCO earned a jurisdictional return, including ECRM, FMCA, and TDSIC revenues, of $284,189,786. This exceeds NIPSCO's authorized amount of $251,987,099 which includes $217,123,567 approved in the 44688 Order in NIPSCO's last base rate case, plus $34,863,534 of actual ECRM, FMCA, and TDSIC operating income during the 12 months ended December 31, 2018. This results in an over-earnings of $32,202,687. While the earnings for the 12 month period ended December 31, 2018, exceed the annual authorized return, Ms. Cherven 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 less than zero; therefore, under Ind. Code § 8-1-2-42.3, she stated no refund is required. Ms. Cherven testified that consistent with the August 22, 2012 Order in Cause No. 44156 RTO 1, NIPSCO excluded $41,244,187 of operating revenues, net of any associated operation and maintenance expenses and net of taxes, earned during the 12 months ended December 31, 2018, associated with NIPSCO's Multi-Value Transmission Projects for purposes of computing its operating income for the 12 months ended December 31, 2018.

Based on the evidence presented, the Commission finds that for the 12 months ended December 31, 2018, NIPSCO did not earn a return exceeding that authorized in its last base rate case, as appropriately adjusted, because NIPSCO's over-earnings were more than offset by NIPSCO's bank of under-earnings.

12. <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 December 31, 2018, was computed in conformity with Ind. Code § 8-1-2-42; (3) NIPSCO had jurisdictional net operating income for the 12 months ending December 31, 2018, 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 December 31, 2018, has been accurately applied; (5) the figures used in NIPSCO's application for a change in the FAC for the quarter ending December 31, 2018, were supported by NIPSCO's books, records, and source documentation; and (6) the OUCC recommends the fuel adjustment factor be approved as requested.

At the hearing, Mr. Guerrettaz testified about his familiarity with MISO's market rules and his review of MISO's rules and business practices manuals. Mr. Guerrettaz testified that he has been involved in FAC proceedings with multiple Indiana utilities over many years. He also testified that the Schedules attached to his prefiled testimony in this proceeding are based upon the OUCC's records, resulting from the OUCC's review of NIPSCO's filings in this and previous FAC proceedings, and review of NIPSCO's books and records during quarterly on-site audits.

Mr. Eckert testified: (1) he has created a working model of Mr. Turner's 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 investor-owned utilities in Indiana; (5) if coal decrement pricing is used, NIPSCO should provide the inputs to its calculation of the coal price (i.e., below cost) decrement, the reasons for the use of any decrement pricing, and when NIPSCO expects the decrement pricing to end; (6) the OUCC reviewed NIPSCO's hedges and believes the hedging costs were reasonable; (7) NIPSCO did not over-earn during the 12-month period covered in this proceeding; (8) NIPSCO is seeking full recovery of the wind invoice amounts NIPSCO now pays for energy received and for dispatch down power (curtailed power); and (9) the OUCC recommends NIPSCO continue to provide updates on its coal inventory.

13. Fuel Cost Adjustment Factor. Based on the evidence, we find NIPSCO has met the tests of Ind. Code § 8-1-2-42(d) for establishing a revised fuel cost adjustment. NIPSCO's evidence presented a variance factor of $0.001122 per kWh and a recoverable interruptible credit factor of $0.000834 per kWh to be added to the estimated cost of fuel for bills rendered during the May through July 2019 billing cycles in the amount of $0.027124 per kWh. This results in a fuel cost adjustment factor credit of $0.001999 per kWh after subtracting the cost of fuel in base rates and adjusting for applicable taxes. Ms. Cherven testified a residential customer using 1,000 kWh per month will experience a decrease of $4.83 on his or her electric bill from the currently approved factor.

14. 2019 Hedging Plan.

A. Background and Relief Requested. In the July 13, 2011 Order in Cause No. 43849 (the "43849 Order"), the Commission (1) approved NIPSCO's initial Hedging Plan ("Initial Hedging Plan"); (2) authorized NIPSCO to request recovery of the transactional costs associated with hedging its fuel supply in accordance with its Initial Hedging Plan as a fuel cost through its quarterly fuel adjustment clause; (3) authorized NIPSCO to request its hedging gains and losses resulting from transactions made in accordance with its Initial Hedging Plan for inclusion as credits and/or charges to the fuel costs recovered through its quarterly fuel adjustment clause; and (4) ordered NIPSCO to file its updated energy supply plan covering the succeeding two-year period on or before May 31 of each year beginning in May 2012.

In the September 5, 2012 Order in Cause No. 44205, the Commission (1) approved NIPSCO's updated energy supply plan covering the succeeding two-year period (July 2012 through June 2014) (the "2012 Hedging Plan"); (2) authorized NIPSCO to request recovery of the transactional costs associated with hedging its fuel supply in accordance with its 2012 Hedging Plan as a fuel cost through its quarterly fuel adjustment clause; (3) authorized NIPSCO to request its hedging gains and losses resulting from transactions made in accordance with its 2012 Hedging Plan for inclusion as credits and/or charges to the fuel costs recovered through its quarterly fuel adjustment clause; (4) ordered NIPSCO to file its updated energy supply plan covering the succeeding two-year period on or before March 31 of each year; and (5) approved a process with respect to future annual updates to the energy supply plan.[6]

In its 44205 S4 Order, the Commission expressed a preference to consolidate the annual review of NIPSCO's hedging plans into the FAC process. In its Compliance Filing on September 30, 2016, in Cause No. 44205 S4, NIPSCO notified the Commission that NIPSCO, the OUCC, and the Industrial Group agreed to schedule and hold a call between December 10th and December 20th each year to discuss the annual electric hedging plan NIPSCO will propose in its February FAC filings. Interested stakeholders will have the opportunity to weigh-in on the proposal during the December call and file testimony concerning the proposal in NIPSCO's FAC proceeding. This schedule will provide the interested stakeholders approximately nine weeks to consider the proposal before its inclusion in NIPSCO's February FAC filing and approximately five additional weeks after NIPSCO's February FAC filing to submit testimony.[7]

In this proceeding, NIPSCO requests Commission approval of its updated energy supply plan covering the two-year period of July 2019 through June 2021 (the "2019 Hedging Plan"). In this filing, NIPSCO proposed two hedge plan scenarios. The first scenario is a plan that takes into account NIPSCO's proposed industrial service structure currently pending in Cause No. 45159 (Attachment 5-A-1). The second scenario is a plan that assumes existing rates are in effect (Attachment 5-A-2). NIPSCO believes it is prudent to execute a plan that takes into account the proposed industrial service structure.

B. Evidence Presented. Mr. Campbell testified that if NIPSCO's requested relief in its pending rate case (Cause No. 45159) is substantially altered, NIPSCO will need to be in a position to update the hedge under Attachment 5-A-2. He testified that the hedging strategy NIPSCO plans to implement between July and October 2019 is generally the same for both of the plans presented; however, under the 2019 Hedging Plan with the new industrial service structure (Attachment 5-A-1), beginning in November 2019, the 2019 Hedging Plan assumes a reduction in overall load and a related reduction in generation to serve that load. There is a similar reduction in the need for MISO purchases beginning in October 2019 because NIPSCO anticipates several of its

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[6] The Commission approved NIPSCO's 2013 updated energy supply plan covering the two-year period July 2013 through June 2015 on July 3, 2013, in Cause No. 44205 S1. The Commission approved NIPSCO's 2014 updated energy supply plan covering the two-year period July 2014 through June 2016 on June 11, 2014, in Cause No. 44205 S2. The Commission approved NIPSCO's 2015 updated energy supply plan covering the two-year period July 2015 through June 2017 (the "2015 Hedging Plan") on June 30, 2015, in Cause No. 44205 S3. The Commission approved NIPSCO's 2016 updated energy supply plan covering the two-year period July 2016 through June 2018 (the "2016 Hedging Plan") on June 22, 2016, in Cause No. 44205 S4 (the "44205 S4 Order"). The Commission approved NIPSCO's 2017 updated energy supply plan covering the two-year period July 2017 through June 2019 (the "2017 Hedging Plan") on April 19, 2017, in Cause No. 38706 FAC 114 (the "FAC 114 Order"), and the Commission approved NIPSCO's 2018 updated energy supply plan covering the two-year period July 2018 through June 2020 (the "2018 Hedging Plan") on April 18, 2018, in Cause No. 38706 FAC 118 (the "FAC 118 Order").

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

large industrial customers to take advantage of a proposal in NIPSCO's pending Cause No. 45159 that allows them greater access to market-based energy and capacity pricing in MISO.

Mr. Campbell testified that NIPSCO is asking the Commission to approve both hedge plan approaches whereby NIPSCO will execute hedge plan scenario one (Attachment 5-A-1) if the new industrial rate structure is in place and hedge plan scenario two (Attachment 5-A-2) if the requested relief in NIPSCO's pending rate case (Cause No. 45159) is substantially altered.

Mr. Campbell testified in support of NIPSCO's 2019 Hedging Plan, opining that it is consistent with the framework and process the Commission approved in the Hedging Orders. Mr. Campbell testified that NIPSCO spoke with the OUCC and the Industrial Group by phone on December 14, 2018, to discuss the 2019 Hedging Plan. Mr. Campbell stated the 2019 Hedging Plan incorporates stakeholder input received from that meeting. He testified the objectives of the 2019 Hedging Plan are to reduce the relative movement in the FAC factor from one period to the next and to limit upside price exposure.

Mr. Campbell explained that the Initial Hedging Plan assumed all of the coal-fired generation facilities within the NIPSCO asset portfolio were fixed in price. Since a majority of NIPSCO's coal contracts are between three and five years in length, and coal pricing has historically been less volatile than natural gas pricing and the MISO market price of power, NIPSCO determined that any coal-fired generation used to meet the power supply needs of NIPSCO's customers could be classified as a fixed price resource. Mr. Campbell testified that any remaining resources that would likely be needed to meet the power supply needs of NIPSCO customers, however, would be classified as floating in price and, thus, considered when developing the hedge plan. He stated the 2019 Hedging Plan also addresses NIPSCO's exposure to natural gas and electricity price volatility associated with supplying electricity to native load customers.

Mr. Campbell explained how the 2019 Hedging Plan is constructed. He testified that NIPSCO determines the monthly volume of MWhs to be hedged by starting with the total number of on-peak MWhs needed to serve NIPSCO's internal load, excluding off-system sales. The expected number of on-peak MWhs for each month is determined through NIPSCO's demand forecasting process based upon historical usage, estimated economic growth rates, and normalized weather. Once the expected number of on-peak MWhs for each calendar month is determined, the PROMOD model is run to determine what resources will be used to meet this expected demand.

Mr. Campbell testified that modifications were made to the PROMOD model to refine the resource allocation process. He stated the PROMOD model is run with forecasted hourly spot market prices for electric energy in the MISO spot market set at a price just above the variable cost of NIPSCO's available coal-fired generation. This is done to remove forecasted purchases from the MISO spot energy market that would be made in lieu of producing energy at NIPSCO's available coal-fired generation facilities when it is economical to do so. He testified these economic spot market energy purchases are removed from PROMOD modeling because they are made at a price below the cost of production of NIPSCO's coal-fired fleet, and available coal generation is flagged in a "Must Run" status to ensure NIPSCO is capturing the physical hedge obtained from its base load assets. Mr. Campbell testified that NIPSCO's remaining on-peak energy requirements were modeled as being supplied either from NIPSCO's Sugar Creek combined cycle gas turbine ("CCGT") generating station ("Sugar Creek") or by purchasing energy from the MISO spot energy market, and these are the energy requirements for which NIPSCO is subject to market price volatility.

Mr. Campbell testified that NIPSCO followed the 2018 Hedging Plan approved in the FAC 118 Order through December 2018 with the exception of the purchase of power and gas contracts relating to September through November 2018. NIPSCO increased purchases of these power contracts beginning September 2018 due to a Sugar Creek maintenance outage change originally scheduled for October 2018 that was moved to September through November.

Mr. Campbell testified that consistent with previous plans, the 2019 Hedging Plan is comprised of two types of futures contracts. The first type of futures contract (approved in the 43849 Order) will be used to hedge the on-peak MWhs exposure related to Sugar Creek, a CCGT plant that uses natural gas to generate power. He stated the modeled volumes of power from Sugar Creek are converted to dekatherms by multiplying the number of MWhs for each calendar month by the heat rate of the Sugar Creek plant, which is approximately 7.5 dekatherms per MWh. Once the number of dekatherms per calendar month is determined, this number is divided by 10,000 (the number of dekatherms in each natural gas futures contract) to arrive at the number of natural gas futures contracts to be purchased for each calendar month of delivery. Mr. Campbell stated these contracts settle financially as opposed to physically, so they will not have any impact on the physical purchase and delivery of natural gas that is required to run the Sugar Creek plant. He noted that a natural gas futures contract settles financially by comparing the purchase price to the settlement price, netting the difference, and then multiplying this dollar difference by 10,000 to get the dollar amount per contract. Dollars change hands without any physical flow of the commodity itself.

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

Mr. Campbell testified the hedges under the 2019 Hedging Plan are being made solely to address native load fuel cost price exposure. The hedges will not change the economic dispatch of NIPSCO's generation facilities or NIPSCO's wholesale electricity sales and purchases; therefore, NIPSCO continues to propose to pass all hedging gains and seek recovery of prudently incurred hedging losses through its FAC filings.

Mr. Campbell explained NIPSCO's proposal for implementing its hedging transactions. He stated the natural gas futures contracts and the MISO Indiana Hub Day-Ahead Peak Calendar-Month Futures contracts will be purchased according to specific schedules, on a dollar cost averaging basis, up to the second to last month before the month of delivery. These purchases will conclude on the second to last month before the month of delivery because monthly natural gas futures contracts settle three business days prior to the month of delivery. According to Mr. Campbell, if the natural gas futures contracts were purchased immediately prior to the month of delivery, the purchase would effectively be made at the same time the contract was settling. Mr. Campbell testified that the MISO Indiana Hub Day-Ahead Peak Calendar Month Futures contracts will be purchased on a dollar cost averaging basis up through and including the month prior to the delivery month. He stated the schedule is broken up into the different types of futures contracts to demonstrate when and what number of contracts will be purchased.

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

Mr. Campbell sponsored an analysis determining the possible impact the 2019 Hedging Plan will have on overall purchased power costs under each of the two proposed hedge plan scenarios. The analysis shows an example of what additional power supply costs could be incurred if market prices increase by 20% from where market pricing was as of the close of business on January 11, 2019, taking into account NIPSCO's proposed industrial service structure pending in Cause No. 45159 ("Attachment 5-E-1") or a plan that assumes existing rates are in effect ("Attachment 5-E-2"). He testified that in the example in Attachment 5-E-1, there could be an additional $14,574,846 of power supply costs (inclusive of CCGT generation and MISO power purchases) and in the example in Attachment 5-E-2, there could be an additional $21,154,981 of power supply costs (inclusive of CCGT generation and MISO power purchases) if market prices rose by 20% for each month of the planned period. The plan period covers July 2019 to June 2021. The analysis also includes the effect the 2019 Hedging Plan could have on these additional power supply costs. If these hedges were in place and the market was stressed upward by 20% for each month in the plan period, the additional power supply costs would be roughly 56% ($8,172,798) in Attachment 5-E-1 and roughly 57% ($11,998,222) in Attachment 5-E-2 of what they would be without the hedge plan in place. However, if prices were to move downward by 20%, power supply costs could have been reduced by $14,574,846 in Attachment 5-E-1 and $21,154,981 in Attachment 5-E-2 through the plan period if no hedge plan had been implemented. The analysis demonstrates how a hedge plan can reduce volatility in power supply costs. While possible savings may be forgone when prices fall, the hedge plan reduces additional costs that may have been incurred when prices rise.

Mr. Campbell testified market conditions are dynamic, and the analysis provided in Attachments 5-E-1 and 5-E-2 is only intended to show the relative impact of the program under these alternative scenarios, assuming market conditions remain the same as they are today. Nevertheless, the analysis provides an indication of the impact this program may have in the future. Mr. Campbell testified NIPSCO has in the past recommended adjustments to the hedge plan approach and continues to evaluate factors that could impact the viability of the currently proposed hedging methodology.

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

Mr. Campbell testified that during the December 14, 2018, stakeholder meeting, NIPSCO proposed two hedge plan scenarios: one based on the new industrial service structure and one based on the current rate structure. He stated no further changes were discussed or proposed. Mr. Campbell reiterated that NIPSCO will continue to have discussions with its stakeholders around the effectiveness of this plan adjustment, may make additional recommendations in the future, and is appreciative of the collaborative nature of the discussions with the OUCC and the Industrial Group around the overall hedge plan approach. Mr. Campbell testified that NIPSCO is asking the Commission to approve both hedge plan approaches, with NIPSCO to execute hedge plan scenario one if the new industrial rate structure is in place and hedge plan scenario two if the relief requested in Cause No. 45159 is substantially altered in that proceeding.

Neither the OUCC nor the Industrial Group raised concerns about the 2019 Hedging Plan, its approval in this Cause, or continuing annual review of NIPSCO's future hedging plans as part of the FAC process.

C. Commission Discussion and Findings. In Cause No. 43849, the Commission found:

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

43849 Order at 10. The Commission finds that NIPSCO's 2019 Hedging Plan is consistent with the approach approved in the 43849 Order.

Filing for approval of the 2019 Hedging Plan in this FAC proceeding is also consistent with the preference the Commission stated in the 44205 S4 Order and NIPSCO's Compliance Filing in Cause No. 44205 S4. No party objected to the reasonableness of the 2019 Hedging Plan or the administrative efficiency of reviewing future annual hedging plans in a similar fashion. The Commission finds that NIPSCO should continue to consolidate the annual review of NIPSCO's hedging plans into the FAC process. When doing so, NIPSCO should expressly request approval of its updated hedging plan when initiating the applicable FAC filing, continue to evaluate the viability of the hedging methodology, and recommend adjustments to the plan if NIPSCO believes a change is reasonable.

Based on the evidence, the Commission finds that both scenarios of the proposed 2019 Hedging Plan are reasonable, consistent with the public interest, and should be approved. The evidence demonstrates NIPSCO has communicated with the OUCC and the Industrial Group in the interest of improving the plan consistent with the Commission's Orders in Cause Nos. 43849, 44205 S1, FAC 114, and FAC 118, and the Commission finds NIPSCO should continue to do so. Should NIPSCO's proposed industrial service structure changes be approved without material alterations in Cause No. 45159, NIPSCO is directed to utilize the version of the 2019 Hedging Plan included in Attachment 5-A-1. But, if material changes are made in NIPSCO's proposal in Cause No. 45159, NIPSCO is directed to utilize the version of the 2019 Hedging Plan included in Attachment 5-A-2. Additionally, in the FAC filing immediately following the issuance of a Commission order in Cause No. 45159, NIPSCO is directed to notify the Commission of disposition of the proposed industrial service structure and confirm which of the two versions of the 2019 Hedging Plan NIPSCO will be implementing.

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

16. **Confidential Information.** On March 26, 2019, NIPSCO filed a motion for protection and nondisclosure of confidential and proprietary information supported by an affidavit showing documents to be submitted to the Commission contained trade secrets within the scope of Ind. Code §§ 5-14-3-4(a) and 24-2-3-2. In its motion, NIPSCO represented that the confidentiality of the information in question had been discussed with all those participating in this proceeding, and they do not object to its designation as confidential. In a March 27, 2019, docket entry, such information was found to preliminarily be confidential, after which NIPSCO and Mr. Rackers submitted the information under seal. The Commission finds such information is 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 by the Commission as confidential and protected from public access and disclosure.

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

1. NIPSCO's requested fuel cost adjustment to be applicable to bills rendered during the May, June, and July 2019 billing cycles or until replaced by a fuel cost adjustment approved in a subsequent filing, as set forth in Finding No. 13 above, is approved on an interim basis subject to refund as set out in Finding No. 15 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. In its next FAC proceeding, NIPSCO shall discuss with all participants in that proceeding whether additional information would be helpful in future FAC proceedings. In its subsequent FAC proceeding, NIPSCO shall report upon these discussions and identify what, if any, additional information stakeholders believe will be helpful in future FAC proceedings, as discussed in Finding No. 7.A. above.

4. NIPSCO shall continue to include in its quarterly FAC filings updates concerning its utilization of the RECs associated with the wind purchases being recovered through the FAC, as discussed in Finding No. 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.

5. NIPSCO shall also continue to include in its quarterly FAC filings the information required by the Commission's April 27, 2011 Order in Cause No. 38706 FAC 90, testimony regarding efforts to mitigate costs incurred for unused train sets, and information about improvements to the generating station heating sheds and any freeze treatment used, as discussed in Finding No. 10 above.

6. 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.

7. NIPSCO's proposed 2019 Hedging Plan (both scenarios) is approved, and NIPSCO shall continue to consult with interested stakeholders in developing future hedging plans. In the FAC filing immediately following issuance of a Commission order in Cause No. 45159, NIPSCO is

directed to notify the Commission of disposition of the proposed industrial service structure and confirm the version of the 2019 Hedging Plan NIPSCO will be implementing.

8. NIPSCO is authorized to request recovery of the transactional costs associated with hedging its fuel supply in accordance with its 2019 Hedging Plan as a fuel cost through its quarterly FAC. Such transactional costs should be separately identified in the schedules supporting each such filing and upon a finding of prudency will be recoverable through NIPSCO's quarterly FAC.

9. NIPSCO is authorized to request its hedging gains and losses resulting from transactions made in accordance with NIPSCO's 2019 Hedging Plan for inclusion as credits and/or charges to the fuel costs recovered through NIPSCO's quarterly FAC. Such credits and/or charges should be separately identified in the schedules supporting each such filing and upon a finding of prudency will be recoverable through NIPSCO's quarterly FAC.

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

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

<u>HUSTON, KREVDA, OBER, AND ZIEGNER CONCUR; FREEMAN ABSENT</u>:

APPROVED:

APR 29 2019

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

Mary M. Becerra

Mary M. Becerra
Secretary of the Commission