ORIGINAL

| Commissioner | Yes | No | Not Participating |
| --- | --- | --- | --- |
| Huston | √ | | |
| Bennett | √ | | |
| Freeman | | | √ |
| Veleta | √ | | |
| Ziegner | √ | | |

**STATE OF INDIANA**

**INDIANA UTILITY REGULATORY COMMISSION**

| | | |
| --- | --- | --- |
| **VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR APPROVAL OF (1) A FUEL COST ADJUSTMENT TO BE APPLICABLE DURING THE BILLING CYCLES OF NOVEMBER AND DECEMBER 2023 AND JANUARY 2024, PURSUANT TO IND. CODE § 8-1-2-42 AND CAUSE NO. 45159, AND (2) RATEMAKING TREATMENT FOR THE COSTS INCURRED UNDER WHOLESALE PURCHASE AND SALE AGREEMENTS FOR WIND AND SOLAR ENERGY APPROVED IN CAUSE NOS. 43393, 45194, 45195, 45310, 45462, AND 45524.** | ) | **CAUSE NO. 38706 FAC 140**<br><br>**APPROVED: OCT 25 2023** |

**ORDER OF THE COMMISSION**

**Presiding Officer:**
**Kristin E. Kresge, Administrative Law Judge**

On August 18, 2023, 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 during the November 2023, December 2023, and January 2024 billing cycles or until replaced by a fuel cost adjustment approved in a subsequent filing, pursuant to Ind. Code § 8-1-2-42 and Cause No. 45159, and (2) ratemaking treatment for the costs incurred under wholesale purchase and sale agreements for wind and solar energy approved in Cause Nos. 43393, 45194, 45195, 45310, 45462, and 45524. NIPSCO concurrently prefiled its case-in-chief which included the direct testimony of NiSource Corporate Services Company employee Kelleen M. Krupa, Lead Regulatory Analyst, and the testimony and exhibits of the following NIPSCO employees:

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

On August 18, 2023, NIPSCO also filed a motion requesting confidential treatment for certain information ("Confidential Information"). In a docket entry issued August 29, 2023, the requested confidential treatment was granted on a preliminary basis.

On August 22, 2023, the NIPSCO Industrial Group ("Industrial Group") filed a petition to intervene. This petition was granted on September 1, 2023.[1]

On September 15, 2023, NIPSCO filed Attachment 1-B, to include inadvertently omitted page 6.

On September 22, 2023, the Indiana Office of Utility Consumer Counselor ("OUCC") prefiled the direct testimony and exhibits of the following:

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

The Commission noticed this matter for an evidentiary hearing at 10:00 a.m. on September 25, 2023, in Hearing Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. By docket entry dated August 31, 2023, the evidentiary hearing was continued to 10:00 a.m. on October 10, 2023 in Hearing Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. NIPSCO, the OUCC, and the Industrial Group, by counsel, participated in this evidentiary hearing, and the testimony and exhibits of NIPSCO and the OUCC were admitted without objection.

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

**1. Commission Jurisdiction and Notice.** Notice of the evidentiary hearing in this Cause was published as required by law. NIPSCO is a public utility as defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to NIPSCO's fuel cost charge; therefore, the Commission has jurisdiction over NIPSCO and the subject matter of this Cause.

**2. NIPSCO's Characteristics.** NIPSCO is a limited liability company organized under Indiana law with its principal office in Merrillville, Indiana. NIPSCO renders electric public utility service in Indiana and owns, operates, manages, and controls, among other things, plant and equipment within Indiana used for the production, transmission, delivery, and furnishing of such service.

**3. Available Data on Actual Fuel Costs.** NIPSCO's cost of fuel to generate electricity and the cost of fuel included in the cost of purchased electricity in NIPSCO's most recent base rate case approved in the Commission's August 2, 2023 Order in Cause No. 45772 ("45772 Order") was $0.033674 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 April, May, and June 2023 averaged $0.027849 per kWh.

**4. Requested Fuel Cost Charge.** NIPSCO seeks to change its fuel cost adjustment from the current fuel cost factor charge of $(0.009817) per kWh for bills rendered during the August, September, and October 2023 billing cycles to a fuel cost charge of $(0.006676) per kWh

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

for bills rendered during the November 2023, December 2023, and January 2024 billing cycles or until replaced by a different fuel cost adjustment approved in a subsequent filing.

The requested fuel cost adjustment includes a variance of $25,394,138 that was over-collected during April through June 2023 ("reconciliation period"). NIPSCO's estimated monthly average cost of fuel to be recovered in this proceeding for the forecasted billing period of November 2023 through January 2024 is $30,810,170, and its estimated monthly average sales for that period are 827,677 MWhs .

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

> (1) the electric utility has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible;
>
> (2) the actual increases in fuel cost through the latest month for which actual fuel costs are available since the last order of the commission approving basic rates and charges of the electric utility have not been offset by actual decreases in other operating expenses;
>
> (3) the fuel adjustment charge applied for will not result in the electric utility earning a return in excess of the return authorized by the Commission in the last proceeding in which the basic rates and charges of the electric utility were approved. However, subject to section 42.3 [Ind. Code § 8-1-2-42.3], if the fuel charge applied for will result in the electric utility earning a return in excess of the return authorized by the commission in the last proceeding in which basic rates and charges of the electric utility were approved, the fuel charge applied for will be reduced to the point where no such excess of return will be earned; and
>
> (4) the utility's estimate[s] of its prospective average fuel costs for each such three (3) calendar months are reasonable after taking into consideration:
>
> > (A) the actual fuel costs experienced by the utility during the latest three (3) calendar months for which actual fuel costs are available; and
> >
> > (B) the estimated fuel costs for the same latest three (3) calendar months for which actual fuel costs are available.

**6. Fuel Costs and Operating Expenses.** NIPSCO's Attachment 1-F shows fuel costs for the 12 months ending June 30, 2023, were $289,659,727 above the amount the Commission approved in the 45159 Order. NIPSCO's Attachment 1-F also shows its total operating expenses, excluding fuel, for the 12 months ending June 30, 2023, were $18,255,361 above the amount approved in the 45159 Order. The Commission finds there have been increases in NIPSCO's actual fuel costs for the 12 months ending June 30, 2023, that have not been offset by actual decreases in other operating expenses.

**7. Efforts to Acquire Fuel and Generate or Purchase Power to Provide Electricity at the Lowest Reasonable Cost.** Mr. Wagner testified that NIPSCO made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible. He testified that during the reconciliation period, of the energy produced by NIPSCO's fossil-fueled generation, NIPSCO's coal-fired generation provided 37.0% of energy generated, and 63.0% of the energy generated was gas-fired. He stated NIPSCO's coal-fired generation consumes coal from various supply regions, with the Michigan City Generating Station ("Michigan City") consuming a mix of Powder River Basin ("PRB") and Northern Appalachian ("NAPP") coal, and Unit 17 and 18 at R.M. Schahfer Generating Station ("Schahfer") consuming Illinois Basin ("ILB") coal.

**A. Fuel Procurement.** In discussing NIPSCO's coal procurement process, Mr. Wagner identified several factors NIPSCO considers when evaluating purchases for a specific generating unit, including the delivered cost, operational costs, cost of emissions controls, and management of coal combustion byproducts. In addition, a coal's combustion and emission characteristics are critical and may eliminate a coal from consideration if these characteristics adversely affect a generating unit's reliability, drastically increase the total cost of generation (fuel and operational costs) or inhibit NIPSCO's ability to comply with emission limits. He testified the reliability of the coal source and the reliability of coal transportation from that source are also critical factors NIPSCO considers.

Mr. Wagner stated NIPSCO purchased coal during the reconciliation period under three supply contracts. These contracts were with Arch Coal Sales Company for PRB coal; American Consolidated Natural Resources for NAPP coal; and Peabody COALSALES, LLC for ILB coal. Mr. Wagner confirmed that NIPSCO has no financial interest in the coal producers currently under contract.

Mr. Wagner testified that producers and customers are generally reluctant to execute long-term contracts with fixed prices without some type of market price adjustment mechanism. He opined that maintaining a price close to market is beneficial to both parties; therefore, a producer and customer may work together to establish an equitable price adjustment methodology. Mr. Wagner testified that, historically, market-based price adjustments in term supply agreements tend to reduce the buyer's cost of hedging since future prices are generally higher than spot and year-ahead prices. In addition to base price adjustments, quality price adjustments are used to maintain the underlying economics of the agreement on a dollar per million British thermal unit ("BTU") basis when the shipment quality varies from guaranteed quality specifications. Mr. Wagner testified that one of NIPSCO's term coal contracts in effect during the reconciliation period had mostly fixed prices specified in the contract, and a portion of the volume under this contract was priced using a coal market index. Another contract had rates that are indexed to generating unit hourly Day-Ahead Locational Marginal Prices ("LMPs"). In addition, all NIPSCO's coal supply agreements adjust the price of coal based on a shipment's quality variances from contract specifications.

Mr. Wagner testified the cost of coal consumed for NIPSCO for the 12 months ending June 30, 2023, was $78.70 per ton or $3.813 per million BTU. The cost of coal consumed during the reconciliation period was $74.65 per ton or $3.673 per million BTU. When compared to the prior reconciliation period, Mr. Wagner stated NIPSCO's delivered cost of coal consumed per ton decreased by $17.64 per ton and was down $0.714 per million BTU. Mr. Wagner testified several factors contributed to the change in the system cost of coal expensed during the reconciliation period, including a reduction in the delivered cost of ILB coal which has a lower contract price of relative to the inventory, for Schahfer. Another contributing factor was an increase in utilization of Michigan City, which consumes PRB coal. Additionally, railroad fuel surcharges decreased due to lower On-Highway Diesel Fuel prices.

Ms. Robles testified there have been no changes to NIPSCO's gas purchasing practices for NIPSCO's generation located off NIPSCO's gas distribution system (Sugar Creek Generating Station) during the reconciliation or forecast period. She further testified that NIPSCO has made every reasonable effort to purchase natural gas to provide electricity at the lowest reasonable price. Based on the evidence presented, the Commission finds NIPSCO has adequately explained its coal and gas procurement decision making, and its acquisition process is reasonable.

**B. <u>Coal Decrement Pricing</u>.** Mr. Wagner testified NIPSCO is not currently utilizing decrement pricing but will continue to update the Commission about decrement pricing in its future FAC filings.

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

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

**C. <u>Renewable Energy Credits ("RECs")</u>.** Ms. Robles provided an update on NIPSCO's treatment of RECs associated with its energy purchases under wind and solar purchased power agreements ("PPAs"). She testified that pursuant to the Commission's July 24, 2008 Order in Cause No. 43393 ("43393 Order"), NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreements for wind energy from Barton Wind Farm on April 10, 2009 and Buffalo Ridge Wind Farm on April 15, 2009. Consistent with the Commission's August 7, 2019 Order in Cause No. 45194 ("45194 Order"), NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Rosewater on November 20, 2020. Pursuant to the Commission's June 5, 2019 order in Cause No. 45195 ("45195 Order") NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Jordan Creek on December 2, 2020. Consistent with the Commission's February 19, 2020 order in Cause No. 45310 ("45310 Order") NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for wind energy from Indiana Crossroads Wind Generation LLC on December 17, 2021. Consistent with the 43393, 45194, 45195, and 45310 Orders, NIPSCO is also crediting any off-system sales created by its wind and solar PPAs. For the months of April, May, and June 2023, NIPSCO received 242,205 MWhs, 179,797 MWhs, and 150,534 MWhs, respectively.

Ms. Robles testified that pursuant to the Commission's May 5, 2021 Order in Cause No. 45462, NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for solar energy from Dunn's Bridge I Solar Generation LLC ("Dunn's Bridge I") on August 4, 2023. Pursuant to the Commission's July 28, 2021 Order in Cause No. 45524, NIPSCO began receiving power and seeking recovery of costs associated with the wholesale purchase and sale agreement for solar energy from Indiana Crossroads Solar Generation LLC ("Crossroads Solar") on August 8, 2023. Therefore, she said that costs associated with the wholesale purchase and sale agreement for solar energy with Crossroads Solar and Dunn's Bridge I are included in NIPSCO's projected fuel costs.

Ms. Robles testified that each megawatt hour of power generated from a qualified resource can be awarded a REC. Since no national standard currently exists, she stated each jurisdiction has set its own regulations upon how to qualify and account for RECs. Ms. Robles testified that NIPSCO receives RECs associated with the power it purchases from Barton, Buffalo Ridge, Jordan Creek, Rosewater, and Crossroads Wind. All RECs are and will be tracked in a renewable energy tracking system. Because NIPSCO's solar projects have reached commercial operation as of August 2023, NIPSCO will receive RECs for these projects, which are anticipated to be handled similarly to current RECs from wind projects. During this FAC period, Ms. Robles testified current vintage RECs were sold. The block sizes and proceeds from the sales were:

| Transaction | RECs Sold | Net Proceeds |
|---|---|---|
| 1 | 75,000 | $ 406,313 |
| 2 | 25,000 | $ 135,438 |
| 3 | 50,000 | $ 270,875 |
| 4 | 50,000 | $ 270,000 |
| 5 | 50,000 | $ 258,563 |
| 6 | 67,324 | $ 341,518 |
| 7 | 10,000 | $ 54,175 |
| 8 | 23,000 | $ 118,939 |
| 9 | 50,000 | $ 270,875 |
| 10 | 30,000 | $ 171,390 |
| 11 | 50,000 | $ 275,438 |
| 12 | 25,000 | $ 147,500 |
| 13 | 100,000 | $ 541,750 |
| 14 | 100,000 | $ 571,300 |
| 15 | 30,000 | $ 171,390 |
| 16 | 20,000 | $ 114,260 |
| 17 | 50,000 | $ 270,875 |
| 18 | 43,103 | $ 246,247 |
| 19 | 150,000 | $ 864,338 |
| 20 | 150,000 | $ 886,500 |
| Total | 1,148,427 | $ 6,387,682 |

Ms. Robles testified that during the reconciliation period, NIPSCO transferred RECs to the Green Power Rider program. The block sizes and proceeds from the sales were:

| Transaction | RECs Sold | Net Proceeds |
|---|---|---|
| 1 | 39,010 | $ 93,625 |
| Total | 39,010 | $ 93,625 |

Ms. Robles testified that NIPSCO has passed and anticipates continuing to pass the proceeds from the sale or transfer of RECs back to its customers through the Purchased Power other than MISO line item. She noted that REC prices are increasing, which is resulting in increasing revenues from REC sales being passed back to customers. Per Ms. Robles, NIPSCO continually monitors and evaluates the marketability for all RECs, and as the possibility for future legislation evolves, NIPSCO will make appropriate changes to its REC strategy.

Ms. Robles stated that NIPSCO now has 25 approved solar and wind customers with facilities registered in M-RETS, with nameplate capacities ranging between 0.05 MW and 2.0 MW. Solar and wind generation volumes are uploaded to M-RETS monthly. During this FAC period, Ms. Robles testified that current vintage solar and wind FIT RECs were sold. The block sizes and proceeds from the sales were:

| Transaction | RECs Sold | Net Proceeds |
|---|---|---|
| 1 | 4,453 | $ 10,966 |
| Total | 4,453 | $ 10,966 |

Ms. Robles stated NIPSCO has and anticipates continuing to pass the proceeds from the sale of FIT RECs back to customers through the Purchased Power other than MISO line item. She noted NIPSCO continues to have discussions with brokers and market participants to determine the best means of marketing the FIT RECs.

Mr. Guerrettaz testified NIPSCO provided a net credit of $6,492,273 to customers including RECs sold to the Green Power Rider program.

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

Ms. Robles testified NIPSCO incorporated forecasted FIT purchases in this filing. She explained that NIPSCO projects FIT purchases for the forecast period based on the average of actual FIT purchases incurred for the 12-month period ending June 30, 2023.

The Commission finds that NIPSCO shall continue to include in its quarterly FAC filings updates concerning its utilization of RECs associated with wind and solar purchases being recovered through the authority granted in the 43393, 45194, 45195, 45310, 45462, and 45529 Orders and any other future renewable purchases.

**D. Electric Hedging Program.** Ms. Robles provided the table below, which shows the hedging contracts purchased during the reconciliation period.

| **Month** | **Power Contacts** | | **Gas Contracts** | |
|---|---|---|---|---|
| | **Actual** | **Var to Plan** | **Actual** | **Var to Plan** |
| April 2023 | 30 | 10 | 31 | 0 |
| May 2023 | 10 | 10 | 38 | 0 |
| June 2023 | 35 | 10 | 37 | 0 |

Ms. Robles stated the execution of these contracts is consistent with NIPSCO's Commission-approved electric Hedging Plan through June 2023. Ms. Robles testified NIPSCO is operating under the updated 2022-2024 Hedging Plan, which began in July of 2022. In future FAC filings, NIPSCO will disclose any additional deviations from the filed and approved plan.

Ms. Robles testified the impact of the hedges during the reconciliation period was a loss of $2,397,586. The net total impact, including broker and clearing exchange fees, was $2,411,577. Broker fees represented 0.12% of the total value of the transactions occurring during the reconciliation period. Ms. Robles testified decisions were made based upon the conditions known at the time of the transactions, and NIPSCO used the same broker it uses for other transactions to limit transaction costs, with the transactions all made in accordance with NIPSCO's approved hedging plan. She stated NIPSCO will continue to solicit input and work with interested stakeholders on any potential changes to its hedging plan as NIPSCO's generation portfolio transitions.

Mr. Eckert testified the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs are reasonable. He testified NIPSCO entered 106 gas and 75 power contracts during the FAC reconciliation period.

The Commission finds that NIPSCO shall continue to include in its FAC filings testimony and evidence of its electric hedging costs and any gains/losses resulting from hedging transactions for which NIPSCO seeks recovery through the FAC.

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

Ms. Robles testified that 73,851 MWhs of purchased power in April 2023, 53,392 MWhs of purchased power in May 2023, and 157,679 MWhs of purchased power in June 2023 were in excess of the Purchased Power Benchmark. She testified that in accordance with the procedures outlined in the 43526 Order, NIPSCO has determined that in June 2023, 1,040 MWhs at an average purchased power cost of $36.89/MWh exceeded the Purchased Power Benchmark and a portion of those purchases is non-recoverable. The remainder of the MWhs 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.

Ms. Robles testified that on August 2, 2023, the Commission issued the 45772 Order, approving NIPSCO's request to eliminate the Purchased Power Benchmark established in Cause No. 41363 from the FAC. She stated because the Benchmark is applicable to the Reconciliation Period in this filing as well as July 2023, which will be included in the next FAC filing, NIPSCO indicated the benchmark will be removed in FAC 142.

OUCC witness Guerrettaz testified about the MWhs that exceeded the Purchased Power Benchmark. He stated the purchases over the benchmark have been determined to be recoverable.

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

Based on the evidence, the Commission finds NIPSCO's identified purchase power costs are properly included in the fuel cost calculation and that NIPSCO has made every reasonable effort to acquire fuel and generate or purchase power or both so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible.

**8. <u>MISO Day 2 Energy Costs</u>.** NIPSCO included in its forecast the operational changes associated with the MISO Day 2 energy market in accordance with the Commission's Orders in Cause Nos. 42685, 43426, and 43665. The total MISO Components of Cost of Fuel included in the actual cost of fuel for April, May, and June 2023 was $94,431.

Ms. Robles explained that a credit of $7,305,261 is reflected as a manual adjustment to the MISO Component of Fuel Costs for April 2023 and a charge of $472 is reflected as a manual adjustment to the MISO Component of Fuel Costs for May 2023. She explained the adjustments are a result of NIPSCO's portion of the 2022 Excess Congestion Refund. This refund is reflected as part of a Miscellaneous Adjustment, which is part of the monthly Transmission Settlement process from MISO. She noted Excess Congestion occurs when the charges assessed by MISO exceed the amount paid to the holders of the FTRs during the previous operating year. NIPSCO classifies this transaction as part of the MISO Cost of Component related to FTRs Revenues and Expenses, even though there is not a MISO charge type to reflect this amount. As a result, NIPSCO makes a manual adjustment to the monthly accumulation of MISO charges and credits from the settlement statements. She stated the Excess Congestion Refund for April 2023 was significantly higher than previous years due to several factors including an increase of monthly FTR auction revenues and increased Day Ahead congestion after hourly FTR funding.

Ms. Robles testified the Real Time Non-Excessive Energy was $1,828,905 in April 2023, $1,371,223 in May, and $1,458,405 in June 2023, primarily driven by unit derates and forced outages that occurred after NIPSCO's units cleared in the Day Ahead market, as well as differences in actual wind production compared to forecast (due mainly to wind speeds). She testified the Day Ahead Marginal Congestion Component plus actual monthly Auction Revenue Rights/Financial Transmission Rights ("ARR/FTR") expenses, less actual monthly ARR/FTR revenues, did not exceed a cost of $2 million in any month within the reconciliation period.

**9. <u>Estimation of Fuel Cost</u>.** NIPSCO estimates its total average fuel costs for October 2023, November 2023 and December 2023 will be $30,810,170 on a monthly basis.

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

Mr. Wagner testified that market dynamics have decreased coal demand globally, which should ease supply constraints for coal-fired utility generators into 2023. He stated that the factors that may impact supply and demand during the forecast period including, but not limited to, power prices, natural gas prices, railroad and coal supplier performance, generating unit performance, weather conditions, and labor disruptions. NIPSCO's contracted purchases are forecasted to meet NIPSCO's 2023 coal delivery requirements and coal producers are obligated to perform under their agreements. Its coal suppliers have reassured NIPSCO that they will meet the contracted supply requirements. The price of coal used for the forecast period consists of mostly fixed prices. Mr. Wagner testified that if power prices continue to decrease, there may be decreases in the cost of coal under NIPSCO's indexed coal supply agreement. If demand exceeds the forecast and current supply obligations, NIPSCO may need to purchase additional supply, which may impact fuel costs during the forecast period.

Mr. Wagner stated the average spot market price of coal during the reconciliation period, when compared to the prior reconciliation period, was $14.48 per ton (down $0.57) for PRB coal, $54.40 per ton (down $35.26) for ILB coal, and $65.17 per ton (down $32.86) for NAPP coal. He stated these are average F.O.B. mine spot market prices only, which do not include the cost of transportation, and actual prices may vary from published indices.

In identifying energy market trends and factors affecting the market for coal and transportation, Mr. Wagner stated wholesale electricity prices were roughly 58% lower during the reconciliation period compared to the same period in 2022. Coal prices have continued to decline. Mild weather in U.S. and low natural gas prices contributed to the reduction in wholesale energy prices. The key drivers that kept upward pressure on electric prices during most of 2022, including strong global energy demand, rising electric demand, high natural gas prices, high coal prices, and high railroad fuel surcharges, continued to ease during the Reconciliation Period. API 2 prices (coal delivered to Amsterdam, Rotterdam, and Antwerp ("ARA")) that had bolstered domestic coal prices earlier in 2022 continued to decline. The resulting U.S. electric energy supply mix, driven by these market forces, is as follows: renewable generation should be 22% of the mix in 2023 and is expected to increase to 25% in 2024, natural gas-fired generation should be 42% of electric generation in 2023 and is expected to decline to 40% in 2024, and coal-fired generation should be 16% in 2023 and is expected to decrease 15% in 2024. The Energy Information Agency ("EIA") expects natural gas prices will increase moderately during the remainder of 2023 and through 2024. Flat production and flat to declining demand should cap pricing. The EIA expects pricing to increase slightly above $3.00 per MMBTU by the end of 2023 and rise to $3.50 per MMBTU during 2024. Bituminous coal prices are 58% lower than year-ago levels and have driven coal-fired generation to the marginal energy source and this should keep coal pricing relatively flat. In the long run, coal demand will continue to fall driven by lower natural gas prices and coal generation being phased out of energy markets worldwide.

Mr. Wagner testified these dynamics continue to drive prices lower in all energy markets during the reconciliation period. He stated coal pricing into Europe (delivered to ARA) has fallen precipitously since 2022. Additionally, coal producers and railroads have typically relied on strong international markets to offset the long-term decline in domestic demand. Strong exports and improved domestic demand during 2022 provided coal producers and coal transporters with increased sales opportunities and price improvements. He noted the EIA expects coal exports should range between 99 to 103 million tons annually through 2024, which may offset some of the losses in domestic markets.

Mr. Wagner testified that Class I railroads have struggled to meet the surge in demand over the last two years and have limited customer shipments for coal as well as other commodities and products they transport. He stated coal supply constraints have been caused by reduced investment in coal production and coal transportation projects, supplier bankruptcies, and mine closures over the last several years. Mr. Wagner testified these supply and capacity reductions could lead to market volatility if energy demand rebounds. The lower coal demand and slowing of railroads' business has stabilized and improved railroad performance during 2023.

Mr. Wagner testified the EIA is forecasting domestic electric power coal demand to decline by nearly 21% in 2023 driven largely by low natural gas prices, increased renewable generation, and coal-fired generation retirements. Additionally, the economic conditions are expected to return to modest growth during the balance of 2023 likely keeping a floor on energy prices.

Mr. Wagner testified that NIPSCO's estimate for the cost of coal consumed for generation in the forecast period is estimated to be $64.76 per ton or $3.265 per million BTU. In developing the forecast period estimate, Mr. Wagner stated NIPSCO's fuel supply group incorporates coal contract prices inclusive of adjustments specified in the agreement, dust treatment costs, freeze conditioning (seasonal) costs, railcar lease cost, railcar maintenance costs, estimates of contract prices (fixed prices and indexed), transportation fuel surcharges using the monthly average price of U.S. On-Highway Diesel Fuel ("HDF"), the Association of American Railroad's All Inclusive Index Less Fuel ("AIILF") adjustments and estimates of future coal market prices. Additionally, the fuel supply group provides a forecast of beginning inventory values in dollars and quantities in tons for each generation station. These assumptions are provided to NIPSCO's energy supply and optimization group to develop the forecast.

Ms. Robles testified NIPSCO completed its forecast for this FAC filing on August 10, 2023, using its production cost modeling system, PROMOD,2 and made reasonable decisions under the circumstances then known.

The Fuel Cost Factor is forecasted to be $37.225 compared to a Base Cost of Fuel of $33.674. Ms. Robles explained that (1) combined cycle generation cost per MWh is higher compared to FAC-139; (2) the credit associated with the OSS Adjustment is forecasted to be lower than in FAC-139 due to reduced opportunities for OSS sales; (3) purchases through MISO is forecasted to be higher on a total MWh basis than in FAC-139; and (4) although the forecasted cost per MWh is lower than FAC-139, it is projected to be higher compared to recent pricing.

Ms. Robles stated to ensure NIPSCO provides electricity to its retail customers at the lowest fuel cost reasonably possible, NIPSCO has utilized the approved Hedging Plan from FAC-134, which became effective July 1, 2022, and NIPSCO will continue to utilize financial hedges under the 2022 Hedging Plan to mitigate economic impacts and volatility within each FAC. Additionally, NIPSCO has added additional wind and solar resources and will continue to add new resources to its portfolio, which do not have variable fuel costs and are much cheaper relative to utilizing coal-fired (steam) generation. She stated NIPSCO will continue to utilize its growing wind, solar, and solar plus storage fleet of assets to economically serve customers.

Mr. Wagner testified two key factors could impact coal transportation costs during the forecast period: power prices and the price of HDF. Power prices may impact coal transportation costs under two transportation contracts that are indexed to station LMPs. Contract transportation rates are forecasted using forward energy prices and have maximum rates that ultimately hedge price exposure. With respect to the price of HDF, two coal transportation agreements also have mileage-based fuel surcharges that vary with changes in HDF which can impact transportation costs. Fuel surcharges under these agreements are calculated monthly using the average weekly spot price of HDF. Mr. Wagner testified fuel surcharge estimates are included in rate projections used to develop comprehensive transportation costs for the forecast period. He stated the spot price of HDF as of August 7, 2023 was $4.239 per gallon, which is a 15% year-over-year decrease. The EIA expects global oil inventories to decrease during the latter half of 2023 and expects diesel prices to average $4.18 per gal during the second half of 2023 and average $3.94 per gallon in 2024. However, the EIA expects declines in Russian petroleum production with increases in non-OPEC country production. This net impact is expected to result in flat diesel prices. Therefore, actual fuel surcharges under NIPSCO's transportation agreements are expected to remain relatively stable during the forecast period.

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

Mr. Wagner testified NIPSCO is proactively administering coal and rail transportation agreements to address any potential coal supply and/or coal transportation shipment issues. Additionally, all anticipated coal supply requirements for 2023 should be met under current supply agreements. Market dynamics have changed significantly from 2022 and demand for both coal and coal transportation globally has lessened, which has reduced the stress on the coal supply chain. NIPSCO also continues to work closely with its rail carriers to ensure coal deliveries meet demand during the forecast period.

Mr. Wagner stated the days of coal inventory supply at Schahfer was approximately 53 days (unchanged from the prior quarter) at the end of the reconciliation period. He testified solid railroad performance and lower consumption resulted in relatively stable inventory at Schahfer. Michigan City's PRB coal inventory was at 36 days and the NAPP inventory was at 40 days at the end of the reconciliation period. Mr. Wagner testified NIPSCO has made every reasonable effort to acquire fuel so as to provide electricity to its retail customers at the lowest fuel cost reasonably possible.

Mr. Wagner testified NIPSCO's fleet size was 923 railcars (seven sets with 5.2% spares) at the end of the reconciliation period. The typical spare railcar pool ranges between three and eight percent. NIPSCO is collecting railcars for return and this has led to variations in the spare railcar count. Mr. Wagner testified during the reconciliation period NIPSCO utilized roughly 50% of its railcar fleet. He explained NIPSCO stored two sets at Schahfer at the start of the reconciliation period and stored three sets there at the end of the period. This was largely due to station maintenance outages (planned and unplanned) and lower energy prices. Michigan City held one set at the station and one set was stored with the Chicago South Shore Railroad due to lower than anticipated consumption. NIPSCO continuously evaluates its railcar needs based on demand and railroad performance estimates. NIPSCO determined that the fleet size should be reduced to 784 railcars (six-unit trains with roughly 4% spares). NIPSCO is in the process of returning 262 railcars by the end of 2023. Mr. Wagner explained that to support this effort, Schahfer personnel collected and assembled 128 railcars during February, March, and April 2023 and this group of cars was delivered to the lease return location during the second week of May. NIPSCO will continue to use commercially reasonable efforts to return the remaining 137 cars to the lessor before the end of the year.

Mr. Wagner testified NIPSCO is reducing the fleet size by 262 railcars in 2023 to mitigate expense. During the reconciliation period, 123 railcars were delivered to the return location and two additional cars were scrapped and removed from the lease. NIPSCO also stored one set of railcars at a third-party location as it generally does when Michigan City enters a planned maintenance outage or if market conditions keep the unit in service. NIPSCO will utilize Michigan City's or Schahfer's trackage (a zero-cost option) or sublease railcars to minimize cost, whenever possible. Mr. Guerrettaz testified the OUCC will continue to review NIPSCO's railcar fleet size. The OUCC asked for additional information for the FAC 141 audit because it noted railcar maintenance cost per ton is projected to increase materially.

Mr. Wagner testified NIPSCO has continued to survey the market to find potential third-party customers interested in sub-leasing railcars; however, there were no viable third-party customers. He said he is aware that some large utilities are holding on to "excess" railcars out of concern that it may be difficult and/or more expensive to lease cars back if demand improves. The number of railcars available in the market has diminished because scrap rates of coal gondola railcars have been aggressive over the last few years and railcar lease rates have increased drastically, which supports the concern of a potential shortage. Overall, NIPSCO's plan to reduce the coal railcar fleet from eight sets to six sets by the end of the year is a prudent balancing of economics and reliability.

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

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

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)** |
|---|---|---|---|
| April | $0.021931 | $0.034786 | 58.62% |
| May | $0.030272 | $0.033148 | 9.50% |
| June | $0.031024 | $0.035019 | 12.88% |
| **Weighted Average Estimating Error** | | | **23.31%** |

Ms. Robles testified the 23.31% difference led to a variance factor of ($10.227). The differences were primarily driven by a combination of (1) lower than anticipated market prices and lower actual steam generation costs due to reduced unit availability and units that were offered into the MISO market but not dispatched by MISO during the reconciliation period; (2) a lower actual cost associated with the MISO Components Cost of Fuel; and (3) REC sales, which helped to mitigate potential increases in the impact during the reconciliation period. At the time the forecast was prepared neither NIPSCO nor the market as a whole anticipated an approximate 22%

decrease in average natural gas prices ($1.988/Dth actual compared to $2.549/Dth estimated) for this reconciliation period; or an approximate 28% decrease in the all-hours average power price in MISO ($29.23/MWh actual LMP compared to $40.30/MWh estimated LMP) for this reconciliation period.

Mr. Guerrettaz testified nothing came to the OUCC's attention while reviewing NIPSCO's filing indicating the projections NIPSCO used for fuel costs and power sales were unreasonable when comparing actual prior quarter and forecasted fuel costs and sales figures.

The Commission finds, based on the evidence, that NIPSCO's estimate of its prospective average fuel cost to be recovered during November 2023, December 2023, and January 2024 billing cycles is reasonable.

**10.** **Return Earned.** Ind. Code § 8-1-2-42.3 and Ind. Code § 8-1-2-42(d)(3) requires the Commission to find that the FAC applied for will not result in the electric utility earning a return over the return authorized by the Commission in the last proceeding in which the basic rates and charges of the utility were approved. NIPSCO's evidence demonstrates that for the 12 months ending June 30, 2023, NIPSCO earned a jurisdictional return, including TDSIC revenues, of $247,384,180. This is $37,308,867 less than NIPSCO's authorized amount of $284,693,047, which includes $258,654,143 approved in the applicable rate cases, plus $26,038,904 of actual TDSIC operating income during the 12 months ended June 30, 2023. NIPSCO calculates the overall earnings bank (sum of the differentials) for the relevant period as $62,800,818; therefore, under Ind. Code § 8-1-2-42.3, NIPSCO did not earn in excess of its authorized net operating income, and no refund is required.

Based on the evidence presented, the Commission finds that for the 12-month period ending June 30, 2023, NIPSCO did not earn a return exceeding that authorized in its last base rate case, as appropriately adjusted.

**11.** **OUCC Report.** In addition to the testimony referenced above, Mr. Guerrettaz testified: (1) the fuel cost element of NIPSCO's power purchases has been calculated by including the additional requirements of various Commission Orders; (2) the variance for the quarter ending June 30, 2023, was computed in conformity with Ind. Code §§ 8-1-2-42, -42.3, and relevant orders; (3) NIPSCO did not have a net operating costs greater than granted in NIPSCO's last general rate case proceeding; and (4) the fuel cost adjustment for the quarter ending June 30, 2023 has been properly applied in conformity with the requirements of Cause No. 38706 FAC 137 and 138. Mr. Guerrettaz stated the OUCC recommends NIPSCO's proposed FAC factor of ($0.006676) per kWh be approved. Mr. Guerrettaz also recommends the Commission order NIPSCO to continue to provide (1) the monthly railcar inventory and explain any deviations that occur from the expected forecast and present all information impacting the cost per ton for the railcar maintenance increase; (2) detailed coal cost charts from each supplier to each station for the three actual months on a going forward basis setting forth the components of coal and transportation; and (3) a copy of all new RFPs and contracts for transportation and coal.

Mr. Eckert testified: (1) he has created a working model of Ms. Robles' purchased power over the benchmark calculation and agrees with this calculation; (2) NIPSCO's treatment of Ancillary Services Market ("ASM") charges follows the treatment the Commission ordered in its

June 30, 2009 Phase II Order in Cause No. 43426 ("Phase II Order"); (3) NIPSCO is continuing to recover Day Ahead Revenue Sufficiency Guarantee ("RSG") Distribution Amounts and Real Time RSG First Pass Distribution Amounts through the FAC pursuant to the Phase II Order; (4) NIPSCO's steam generation costs are higher than the other large electric investor owned utilities in Indiana and NIPSCO's actual monthly cost of fuel (mills/kWh) is comparable to the other large electric investor owned utilities in Indiana; (5) NIPSCO should continue to update the Commission on its coal inventory and coal price decrement; (6) if coal decrement pricing is used, NIPSCO should provide justification and documentation supporting the need for and utilization of coal decrement pricing, as well as specify when it expects coal decrement pricing to end and provide inputs to its calculation of the coal price decrement; (7) the OUCC reviewed NIPSCO's hedges and believes the hedging profits, losses, and costs were reasonable; (8) NIPSCO provided information regarding Buffalo Ridge, Barton, Jordan Creek, Rosewater, and Indiana Crossroads; and (9) NIPSCO provided an update on the status of the Railroad Litigation.[3] OUCC witness Eckert further testified that a residential customer using 1,000 kWhs in September 2023 will pay $183.92 (excluding taxes), which consists of $175.90 in base charges set in NIPSCO's last approved rate case (Cause No. 45772), $(9.82) in a fuel adjustment clause credit, and $8.02 in non-FAC trackers.

**12. Fuel Cost Adjustment Factor.** Based on the evidence, the Commission finds NIPSCO has complied with the tests of Ind. Code § 8-1-2-42(d) for establishing a revised fuel cost adjustment. NIPSCO's evidence presented a variance factor of ($0.010227) per kWh to be added to the estimated cost of fuel for bills rendered during the November 2023, December 2023, and January 2024 billing cycles in the amount of $0.026998 per kWh. This results in a fuel cost adjustment factor of ($0.006676) per kWh, after subtracting the cost of fuel in base rates. A residential customer using 1,000 kWh per month will experience an increase of $3.14 on his or her electric bill from the currently approved factor.

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

**14. Major Forced Outages.** Consistent with past Commission Orders, Mr. Saffran sponsored Attachment 4-A describing each major forced outage NIPSCO's generating units experienced during the second quarter of 2023, including the length and cause of each major forced outage, the generating unit involved, and proposed solutions to prevent such outages from reoccurring. For purposes of his presentation, a major forced outage is a unit forced outage lasting longer than three consecutive days. He also sponsored Confidential Attachment 4-B providing a root cause analysis for forced outages if an analysis was completed at the time of the FAC filing.

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[3] On September 30, 2019, NIPSCO filed a complaint in the United States District Court for the District of Columbia against the Union Pacific Railroad Company, BNSF Railway Company, CSX Transportation, Inc., and Norfolk Southern Railway Company (currently pending in Civil Action No. 1:19-cv-02927-PLF) for illegally conspiring to use rail fuel surcharges as a mechanism to fix, raise, maintain, and stabilize the prices of rail freight transportation services sold in the United States (the "Railroad Litigation").

**15.** **Status of Railroad Litigation.** In accordance with the Commission's Order in Cause No. 38706 FAC 125, Ms. Krupa testified the Railroad Litigation remains pending, and as of June 30, 2023, NIPSCO has deferred $4,550,145 in associated legal costs. Mr. Wagner advised the Railroad Litigation remains in the expert discovery phase and was consolidated for pre-trial purposes in Multi-District Litigation. On August 2nd and 3rd, NIPSCO's expert witness was deposed by the defendants' attorneys regarding his initial expert report, which was provided to the defendants as part of required expert disclosures. NIPSCO's claim in the Railroad Litigation relies, in part, on the opinion of its expert witness. Defendants' experts provided their responsive expert reports on August 15th pursuant to the applicable court rules and the procedural schedule issued by the judge. No substantive determinations have occurred in the Railroad Litigation. The Commission finds NIPSCO provided an update on the status of the Railroad Litigation as ordered in FAC 125 and should continue doing so.

**16.** **Confidential Information.** On August 18, 2023, NIPSCO filed a motion for protection and nondisclosure of confidential and proprietary information, which was supported by an affidavit showing document to be submitted to the Commission contained trade secrets within the scope of Ind. Code §§ 5-14-3-4 and 24-2-3-2. In a docket entry issued August 29, 2023, such information was found to preliminarily be confidential, after which NIPSCO 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 November 2023, December 2023, and January 2024 billing cycles or until replaced by a fuel cost adjustment approved in a subsequent filing, as set forth in Finding No. 12 above, is approved on an interim basis subject to refund as set out in Finding No. 13 above.

2. Prior to implementing the approved rates, NIPSCO shall file the tariff and applicable rate schedules under this Cause for approval by the Commission's Energy Division. Such rates shall be effective on or after the Order date subject to Division review and agreement with the amounts reflected.

3. NIPSCO shall continue to include in its quarterly FAC filings updates concerning its utilization of the RECs associated with the wind purchases being recovered through the FAC, as discussed in Finding No. 7C 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. 7D above.

4. NIPSCO shall also continue to include in its quarterly FAC filings the information required by the Commission's April 27, 2011 Order in Cause No. 38706 FAC 90 and testimony regarding efforts to mitigate costs incurred for unused train sets, as discussed in Finding No. 9 above.

5. NIPSCO shall also include in its quarterly FAC filings information related to Day Ahead Marginal Congestion Component and the cost of coal stacks from each supplier to each station for the three actual months on a going forward basis and shall also provide a copy of all new RFPs and contracts for transportation and coal to the extent such are issued.

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. 7B above.

7. NIPSCO shall continue to include in its quarterly FAC filings an update on the status of the Railroad Litigation required by the Commission's January 22, 2020 Order in Cause No. 38706 FAC 125, as discussed in Finding No. 15 above.

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

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

**HUSTON, BENNETT, VELETA, AND ZIEGNER CONCUR; FREEMAN ABSENT:**

**APPROVED: OCT 25 2023**

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

Dana Kosco Digitally signed by Dana Kosco Date: 2023.10.25 10:17:08 -04'00'

**Dana Kosco**
**Secretary of the Commission**