APPLICATION OF DUKE ENERGY INDIANA, LLC FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR ELECTRIC SERVICE, FOR APPROVAL OF A CHANGE IN ITS FUEL COST ADJUSTMENT FOR HIGH PRESSURE STEAM SERVICE, AND TO UPDATE MONTHLY BENCHMARKS FOR CALCULATION OF PURCHASED POWER COSTS IN ACCORDANCE WITH INDIANA CODE § 8-1-2-42, INDIANA CODE § 8-1-2-42.3 AND VARIOUS ORDERS OF THE INDIANA UTILITY REGULATORY COMMISSION

ORDER OF THE COMMISSION

Presiding Officers:
David E. Ziegner, Commissioner
David E. Veleta, Senior Administrative Law Judge

On January 26, 2017, Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company") filed with the Indiana Utility Regulatory Commission ("Commission") an Application in Cause No. 38707 FAC 111, for approval of a change in its fuel adjustment charge ("FAC") for electric and steam service and to update monthly benchmarks for purchased power costs. On January 31, 2017, Michael A. Mullett and Patricia N. March, and Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor") filed Petitions to Intervene, which were granted by the Presiding Officers on February 9, 2017.

As part of its case-in-chief in Cause No. 38707 FAC 111, Duke Energy Indiana presented testimony describing a forced outage commencing on August 30, 2016 and lasting 98 days at Duke Energy Indiana's Cayuga Station Unit 1 ("2016 Outage"). On March 2, 2017, Nucor filed a motion requesting the Commission initiate a subdocket for the purpose of investigating the 2016 Outage and its impact on the Company's fuel costs. In the Commission's April 26, 2017 order in Cause No. 38707 FAC 111, we granted the motion for subdocket as it related to the 2016 Outage, but allowed the Company to collect the related fuel cost revenues on an interim basis subject to the outcome of this subdocket.

On May 16, 2017, and May 19, 2017, Citizens Action Coalition of Indiana, Inc. ("CAC") and Duke Energy Indiana Industrial Group ("Industrial Group"), respectively, filed Petitions to Intervene in this subdocket, which were granted by the Presiding Officers on May 31, 2017.

Carolinas, LLC; and Scott A. Burnside, Manager, Unit Commitment for Duke Energy Carolinas LLC.

On September 14, 2017, the OUCC prefiled the direct testimony of Michael D. Eckert, Senior Utility Analyst for the OUCC's Electric Division; Nucor prefiled the direct testimony and exhibits of Richard A. Polich, P.E., Managing Director of GDS Associates, Inc.; and Industrial Group prefiled the direct testimony and exhibits of Nicholas Phillips, Jr., Managing Principal of Brubaker & Associates, Inc. On October 17, 2017, the Company filed a Motion to Strike portions of the testimony of Nucor's witness Richard A. Polich ("Motion"). Nucor filed its response to the Motion on October 27, 2017. Duke Energy Indiana filed its reply on November 3, 2017.


A public evidentiary hearing was held in this Cause on February 5, 2018, at 9:30 a.m., in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. The Company, OUCC, Nucor, CAC, and Industrial Group appeared and participated at the hearing. At the hearing in this Cause, Duke Energy Indiana withdrew its Motion.

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

1. **Notice and Commission Jurisdiction.** Notice of the hearing in this Cause was given as required by law. Duke Energy Indiana is a public utility within the meaning of Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to the Company's rates and charges related to adjustments in fuel costs. Therefore, the Commission has jurisdiction over the parties and the subject matter of this Cause.

2. **Duke Energy Indiana's Characteristics.** Duke Energy Indiana is a public utility corporation organized and existing under the laws of the State of Indiana with its principal office in Plainfield, Indiana, and is a second tier wholly-owned subsidiary of Duke Energy Corporation. Duke Energy Indiana is engaged in rendering electric utility service in the State of Indiana and owns, operates, manages, and controls, among other things, plant and equipment within the State of Indiana used for the production, transmission, delivery and furnishing of such service to the public. The Company also renders steam service to one customer, International Paper.

3. **Relief Requested.** Duke Energy Indiana requests approval of the Settlement Agreement, in its entirety. Specifically, Duke Energy Indiana requests: (1) approval to credit customers $3 million to offset the costs of purchased power incurred during the 2016 Outage, to be refunded through the next FAC proceeding; (2) a determination that Duke Energy Indiana will file, in subsequent FAC proceedings, any root cause analysis ("RCA") performed during the normal course of business for forced outages of units of 100 MW or more lasting more than 100 hours, in accordance with Duke Energy Indiana's standard protocol for determining when to conduct an RCA in effect at the time of the outage; and (3) a determination that Duke Energy Indiana will, in subsequent FAC proceedings, calculate an estimate of the impact on native load fuel costs for any major forced outages on units larger than 100 MW that last more than 60 days in duration.
4. **Duke Energy Indiana’s Case-In-Chief.**

A. **Mr. Luke.** Mr. Luke testified that although a formal RCA is not performed as a result of every outage, one was performed by the Company for the 2016 Outage. Duke Energy Indiana considers health and safety issues, environmental impact, the extent of the equipment damage, and the impact on megawatt loss when determining whether to perform an RCA. Mr. Luke testified that the RCA was performed by a diverse internal team consisting of a Qualified Investigation Team Lead and subject-matter experts. Mr. Luke summarized the conclusions of the 2016 Outage RCA which found that stator bar T21 overheated and the insulation system failed causing a ground fault of the A-phase of the stator winding. The probable cause of the overheating was the presence of a small section of masking tape, which had been properly placed over the ventilation tubes on the inlet end of stator bar T21 to facilitate painting of the stator winding during the 2014 planned outage. The masking tape was not properly removed, which restricted air flow through stator bar T21 causing the stator bar to overheat over time. Mr. Luke testified that the Company’s contractor for the 2014 planned outage work, Alstom, placed the masking tape over the ventilation tubes in order to apply epoxy tagging paint over the stator windings. He stated that Alstom was responsible for removing the tape at the end of the maintenance work. Under the contract, Alstom was required to account for foreign materials, such as masking tape, before closing the generator. Mr. Luke testified that the RCA recommended corrective actions to prevent a similar incident from happening in the future, which the Company has completed.

Mr. Luke testified that Duke Energy utilizes a standard Generator Maintenance Program which recommends performing maintenance tasks at nominal frequency based upon original equipment manufacturer (“OEM”) recommendations, industry research, and the Company’s operating experience. Preventative, predictive, and corrective maintenance is managed through the Company’s work management process. Mr. Luke testified that the Company has followed the Company’s Generator Maintenance Program at Cayuga Station. He testified that Duke Energy Indiana also considers OEM recommendations when establishing unit maintenance requirements, along with the unit condition assessment.

Mr. Luke testified that from 2001 through 2016, the average equivalent forced outage rate (“EFOR”) for Cayuga Unit 1 was 5.02%, which is better than the industry average EFOR of 7.32% for midsized coal units over that same period. He stated that based on these metrics, Cayuga Unit 1 has been more reliable than the average midsize coal unit. Mr. Luke testified that Duke Energy Indiana operated and maintained Cayuga Unit 1 in a reasonable and prudent manner prior to the 2016 Outage. There were no avoided or incomplete maintenance activities that could have prevented the outage.

Mr. Luke testified that Duke Energy Indiana is self-insured through an affiliate for the property damage incurred at Cayuga Unit 1, which has a $1 million deductible. He testified that the repairs made to Unit 1 during the 2016 Outage totaled approximately $9.5 million, and an insurance claim is pending. He also testified that the Company is working with the contractor, Alstom, to come to a reasonable resolution. Mr. Luke testified that Duke Energy Indiana uses best in class maintenance practices for its generating units.
B. **Mr. Cornelius.** Mr. Cornelius described Cayuga Station as a two-unit generating facility built between 1970 and 1972, with a capacity of 1,075 MW (gross). He testified that the fundamental purpose of the stator bars is to form the winding around the rotor to collect the magnetic forces from the rotating shaft to generate electricity. The stator is the stationary portion of the generator, while the rotor rotates. Mr. Cornelius explained that there are two types of stator bars in a generator – top bars and bottom bars, based on their location in the stator. There are 36 top and 36 bottom stator bars, each approximately 30 feet in length, within the Cayuga Unit 1 generator. These combined 72 bars are referred to as the stator “winding.”

Mr. Cornelius testified that in the fall of 2014 Duke Energy Indiana hired Alstom to perform a major turbine generator overhaul on Cayuga Unit 1 (“2014 Outage”). The generator was disassembled, the generator rotor was removed for a complete rotor rewind, and the stator was inspected, tested, and underwent routine maintenance. A new generator hydrogen core monitor was also installed, which detects scorched insulating material within the generator. He testified that during the 2014 Outage Alstom applied epoxy tagging paint to the internal components of the generator, which is an important part of normal maintenance on the generator. This involved placing masking tape on the ventilation tubes at the ends of the stator bars to prevent any paint from entering the tubes and potentially blocking or restricting air flow. Mr. Cornelius testified that epoxy tagging paint is routinely applied to the end winding during major outages to help protect the insulation over the conductors that are in the stator bars. He testified that the fresh paint assists in locating issues with vibration and also has certain compounds that can be released and detected by the generator hydrogen core monitor in the event of overheating. Mr. Cornelius testified that the majority of the painting was performed after the generator stator was inspected, tested, and repaired but before the rotor was reinstalled. It is common practice to apply touch-up paint after the rotor installation.

Mr. Cornelius described the various testing performed on the stator during the 2014 Outage which confirmed the condition of the stator winding insulation and stator, as a whole, were in very good condition given the age of the generator. Mr. Cornelius testified that the Company required its contractors, such as Alstom, to establish cleanliness control/foreign material exclusion practices to ensure dirt, contaminants, or other foreign materials were not introduced into the equipment. The contract with Alstom included such practices. Mr. Cornelius testified that after the 2014 Outage there were no problems with the generator or operating parameters that would have given the Company any indication that a failure was imminent.

Mr. Cornelius testified that a ground fault in the generator stator winding caused Cayuga Unit 1 to trip on August 30, 2016. After confirming the functionality of the relay itself, the generator step up transformer and Isophase Bus, additional testing confirmed a ground on the ‘A’ phase of the generator. On September 2, 2016, Siemens and Duke Energy Turbine Generator Services (“TGS”) were mobilized to the site to begin disassembly of the generator. He testified that a visual inspection of the generator stator bars on the exciter end identified tape covering the ventilation holes on the T21 bar, but it wasn’t until the turbine end endbell was removed that the fault location was visually identified by signs of charring and soot on stator bar T21. Mr. Cornelius testified that the Company determined the best repair option to be a complete rewind of the generator stator, which took place during the fall 2016 outage and lasted approximately 100 days. He testified that prior to the 2016 Outage, a full generator rewind of Cayuga Unit 1 was planned for 2022. Although a major outage is still planned for 2022, since a full stator rewind will no longer be necessary (for another 35-45 years) the duration of that outage may be reduced.
two to four weeks from the 10.3 weeks that was previously planned. Mr. Cornelius testified that in his 20 plus years of experience with major generator outages, he has never before encountered an incident where tape from epoxy tagging painting over vent tubes caused an incident with the generator. He testified that the Company took all necessary steps to return Cayuga Unit 1 to service as quickly as possible.

C. Mr. Fischli. Mr. Fischli testified that as the Company’s TGS Generator Program Manager, he investigated the initial cause of the 2016 Outage to ensure that the correct repair and resolution was identified and executed to prevent recurrence of the failure. In this role, he reviewed the Cayuga Unit 1 inspection results daily during the generator disassembly as well as the historical maintenance records for Cayuga Unit 1 to identify any contributing factors to the failure. He testified that he also worked with various vendors to compile a list of repair options and prices. Mr. Fischli testified that after confirming the ground on the A phase of the generator was internal to the generator, it was disassembled to identify the exact location of failure and determine the necessary repairs. He testified that Siemens assisted in the troubleshooting and failure diagnosis, performed electrical testing to confirm the failure, and disassembled the generator to facilitate a visual inspection.

Mr. Fischli testified that his review of the historical maintenance records of the unit showed no contributing causes to the 2016 Outage. Since 1989, maintenance records showed consistent major maintenance on the generator on a seven to nine year interval, which aligns with current OEM general generator maintenance philosophy. He also testified that there were no signs of degraded condition of the unit based on the 2014 generator overhaul test results. Mr. Fischli testified that after Siemens removed the exciter end (“EE”) endbell, a visual inspection of the generator stator bars on the exciter end of the machine identified masking tape covering the ventilation holes on the T21 stator bar. No visual indications of a fault location were seen on the exciter end linking the tape to the ground fault. He testified that once the turbine end (“TE”) endbell was removed, a fault location was visually identified by signs of soot and charring on stator bar T21. Mr. Fischli testified that the primary damage occurred on T21 stator bar, with a breach of the insulation where the ground fault shorted to the stator core iron. After the T21 stator bar was removed, the bottom bar in the slot B21 was also noted to be charred with mechanical insulation damage, although B21 insulation had not yet been electrically compromised. The stator core iron where the ground fault occurred was not damaged.

Mr. Fischli testified that the leading cause of failure was blocked ventilation from the two, four to five inch long pieces of paint-covered masking tape that were inadvertently left on the ventilation tubes on top stator bar 21, which allowed T21 to overheat during operation over a period of time. He testified that the blocked ventilation caused accelerated insulation degradation. He testified that the T21 stator bar was also impacted by the thermal cycling of the bar. Mr. Fischli testified that Cayuga Station could not likely have detected this overheating earlier since the machine would not have been reopened absent major extenuating circumstances.

Mr. Fischli testified that the equipment installed in the unit to monitor stator health at the time of the 2016 Outage met OEM recommendations. A combination of the original manufacturer’s embedded resistance temperature detectors (“RTDs) to monitor the hydrogen gas temperature inside the generator, as well as the hydrogen core monitor installed during the 2014 Outage to detect any overheating in the generator, were in use at the time of the 2016 Outage. He testified that there were no temperature alarms or core monitor alarms from the time of the
2014 Outage until the 2016 Outage that would have indicated overheating within the generator. He explained that the core monitor picks up any scorched paint or insulation compounds circulating within the cooling gas in the generator. The location of the fault was embedded approximately four inches into the slot, which is tightly packed with filler and wedges to lock the stator bar in place during operation. Mr. Fischli opined that the burned compounds that were emitted by the overheating on this bar remained trapped within the tightly packed materials and never made it out into the main cooling gas flow for the core monitor to detect and alarm operators. At the time of the 2016 Outage the ground fault provided enough mechanical stimulation to blow the scorched compounds out into the general gas flow, causing the core monitor to alarm at that point. Mr. Fischli testified that embedded RTDs have limited usefulness as they only read a “spot temperature” at the exact location of the RTD. He explained how the embedded RTD is also a diluted indication because it indicates the average temperature of the top bar, bottom bar, and bulk stator core temperature in the area.

Mr. Fischli testified that Alstom recommended and installed several embedded RTDs between the top coil and the top stator wedge during the 2014 Outage. He testified that after the generator was returned to service following the 2014 Outage, it was discovered that RTD 14 was not compatible with the distributive control system and therefore did not report valid or useable temperature readings. A combination of OEM embedded RTD’s and gas discharge temperature detectors were in use for monitoring the hydrogen gas temperature inside the generator, as well as the hydrogen core monitor, at the time of the 2016 Outage. Mr. Fischli testified that the significant distance between the fault location and RTD 14 would have impaired RTD 14’s thermal response to the elevated temperature even if the indicator was functional.

Mr. Fischli testified that to minimize the 2016 Outage duration, while the unit was being disassembled to determine the cause of the outage, TGS solicited several bids for various work scope options which would vary dependent on the exact location and nature of the fault. Mr. Fischli prepared an analysis identifying available options and to assess the benefits and risks of each repair option. Of the two options considered, partial or a full rewind, Mr. Fischli recommended a full stator rewind of the Cayuga Unit 1 generator. He explained that due to a long-standing problem with end winding vibration and the fact that the generator was nearing the end of the nominal machine life as designed by the OEM, the practical choice to minimize overall cost to the customer was to perform the full rewind, eliminating the need to perform another stator rewind for the expected life of the generator. He testified that another factor was that Siemens could expedite delivery of the stator bars such that the full rewound outage duration was not significantly different from the partial rewind.

Mr. Fischli’s economic assessment performed as part of his analysis evaluated the energy market impact of an extended outage for partial repair in 2016 combined with another extended outage in 2018 for full stator rewind. This analysis suggested a full stator rewind in emergent manner would be more prudent than planning another extended outage for a full stator rewind in the near future. Mr. Fischli explained that the generator design, with the Sesi-Ring support cone on each end, was a key contributor as to why a partial rewind was not recommended. Since the stator bars were epoxied to the support cone to enhance rigidity of the structure, there was a high risk of damage to the stator bars upon removal of the support cone. This would have required repair of all 36 top bars and extended a partial rewind outage significantly. In addition, Mr. Fischli testified that multiple stator bars had to be removed in order to remove the B21 bottom bar for repair. He stated that it is not uncommon to damage stator bars due to the mechanical stress applied during the
removal process. A number of bars were significantly warped after removal, which would have required them to be replaced as well, further extending the outage duration for a partial rewind option. Mr. Fischli testified that the best case partial rewind, assuming no issues were encountered requiring additional replacements, would involve replacing 16 stator bars, which would have left the remaining 56 stator bars in an at-risk condition. Had a partial rewind been performed, a full rewind was recommended to move up from 2022 to 2018 to address the remaining risk on the 56 bars causing an additional outage impact. Mr. Fischli testified that the decision to proceed with the full stator rewind was made based on the risk assessments of potential damage and the high probability of occurrence in a partial rewind scope option. Confirmation of the identified risk during bar removal for the full stator rewind validated that the optimum decision was made to limit total outage duration and cost to customers. Mr. Fischli testified that a stator bar analysis performed by Siemens after the 2016 Outage validated TGS’ preliminary conclusion that the cause of failure was blocked ventilation from the masking tape over the ventilation tubes on top stator bar 21, causing T21 to overheat during operation over a period of time.

D. Mr. Burnside. Mr. Burnside explained how his team calculated the impact of the 2016 Outage on native load fuel costs using the production costing model Sumatra. He testified that the Sumatra model incorporates system information such as heat rates, emission rates, generating unit fuel costs, emissions allowance costs, and unit variable operating and maintenance costs. Also included as inputs are actual hourly data, including native load demand, generating unit output from MISO, and actual native load purchased power information from the billing system. Sumatra then “economically dispatches” or matches, on an hourly basis, the demand (load) with available supply resources (i.e., generation or purchases) that are economically “stacked” (prioritized based on production costs, lowest cost to highest cost). Consequently, Sumatra economically allocates the production costs for serving native load. Mr. Burnside testified that the Sumatra analysis provided a starting point from which to prepare an estimate of the impact of the 2016 Outage native load fuel from August 30 through December 7, 2016. He then had to make many assumptions for a “what if” analysis outside of Sumatra.

Mr. Burnside testified that the results of the analysis concluded that native load costs were approximately $6.90 million higher than they would have been if Cayuga Unit 1 had been in service during the time period of the 2016 Outage. The retail portion of the cost is estimated to be $6.21 million. He testified that he looked at four separate components to calculate native load costs: First he added (1) the lost financial margin on MWh output from Cayuga Unit 1 was estimated to be $7.60 million; and (2) the cost of purchasing auxiliary power for Cayuga Unit 1 during the 2016 Outage was $0.57 million. He then subtracted (3) approximately $0.68 million of emission allowance and reagent costs at Cayuga Unit 1 that were avoided during the 2016 Outage; and (4) future FAC related costs of approximately $0.59 million avoided by fully rewinding the stator versus waiting until a later planned outage.

Mr. Burnside testified that it was necessary to make assumptions about the Midcontinent Independent System Operator (“MISO”) market to estimate the lost financial margin. The actual locational marginal pricing (“LMPs”) at Cayuga Unit 1 pricing node were affected by the absence of the unit and are therefore an unreliable indicator of what prices would have been if the unit had been online. He testified that a proxy LMP, equal to the actual day-ahead LMP at the CIN.PSI load zone adjusted by the historic basis difference between the load zone and Cayuga Unit 1 node, was used to calculate the lost financial margin. Mr. Burnside explained how the proxy LMP and lost financial margin were calculated. He also testified that the off-line auxiliary power cost is not
an estimate but the actual cost of off-line auxiliary power purchased from MISO during the outage. The avoided cost of emission allowances and reagents was calculated by multiplying the avoided MWhs of Cayuga Unit 1 production by the applicable $/MWh NOx allowance and lime/limestone rates.

Mr. Burnside testified that future FAC related costs were avoided by fully rewinding the stator during the 2016 Outage rather than waiting until a later planned outage. He estimated that Cayuga Unit 1 would be capable of earning a financial margin of approximately $2.6 million during March through May 2022 if there were no planned outage whatsoever. He assumed the 2022 outage would be shortened by three weeks which represents 22.8% of the three-month period. He testified that if the 2022 outage is reduced by three weeks then native load customers would receive the benefit of an additional $593,000 in financial margin.

Mr. Burnside testified that he believes his analysis to be reasonable given that it is not possible to precisely model how MISO would have calculated LMPs and how MISO would have dispatched Cayuga Unit 1 if the unit had been online.

5. **OUCC and Intervenor’s Case-In’Chief Evidence.**

A. **OUCC.** Mr. Eckert described the review and analysis he conducted. He explained that the Duke Energy Indiana insurance policy covering the damage to Cayuga Unit 1 has a $1 million deductible. The Company did not have any insurance that covered lost revenue or any purchased power costs that may have been incurred to replace that generation. He testified that the insurance adjuster’s third report stated the amount of recovery that Duke Energy Indiana would most likely get from its contractor as $34,986. Mr. Eckert testified that Duke Energy Indiana is pursuing claims against the contractor related to the 2016 Outage. Mr. Eckert stated the OUCC recommends that Duke Energy Indiana report the amount of recovery received from the contractor to the Commission, so that the Commission may determine whether a credit to ratepayers is appropriate to offset the cost of purchased power necessitated by the 2016 Outage. Finally, Mr. Eckert opined that the Company should have provided a more detailed outage analysis in FAC 111.

Mr. Eckert offered three OUCC recommendations: (1) leave the rates in this Cause as interim subject to refund until Duke Energy Indiana and the contractor have finalized the additional claim process; (2) require Duke Energy Indiana to report the conclusion of the claim process to the Commission and the OUCC, once finalized, in a future FAC proceeding, including any amount of recovery received from the contractor; and (3) require Duke Energy Indiana to provide outage analyses reports, including RCAs, on major forced outages of units of 100+ MW lasting 100+ hours as part of Duke Energy Indiana’s standard FAC workpaper package.

B. **Industrial Group.** Mr. Phillips testified that Duke Energy Indiana was imprudent in allowing Unit 1 to go back into operation without removing the masking tape on the stator vent, and the Company has not demonstrated that the additional fuel costs incurred as a result of the 2016 Outage were prudently incurred. He testified that because the Company’s fuel cost analysis was not performed using PROMOD, it is unclear whether the 2016 Outage cost ratepayers more than what the Company presented. He added, that even if one accepts Duke Energy Indiana’s methodology, he disagreed with the inclusion of 2022 “future FAC related costs avoided” as a result of performing a full rewind on Cayuga Unit 1 in 2016. He stated that
if the scheduled outage is in fact shorter than anticipated in 2022, as suggested by the Company, any avoided costs will be passed through to customers at that time.

C. **Nucor.** Mr. Polich provided an overview of the 2016 Outage and contended that it was avoidable and Duke Energy Indiana customers should not bear the economic impact of the outage. He discussed the generator temperature monitoring equipment in place at the time of the 2016 Outage. Mr. Polich disagreed with Mr. Fischli’s opinion that the embedded RTDs would not have detected the overheating in stator bar T21. In his opinion, the temperature reading by the stator bar T21 embedded RTD would have been diluted, but the order of magnitude of the temperature increase was sufficient to be detectable. Mr. Polich stated that proper use of trend monitoring and comparison of stator bar embedded RTD temperatures would have indicated stator bar T21 was overheating. He said this should have triggered an alarm in the Cayuga Unit 1 Distributive Control System (“DCS”) or resulted in notification to the plant operators of an anomaly in the generator temperature readings. He added that because the RTDs were not tested for compatibility with the Cayuga Unit 1 DCS, the RTDs were not functional and no information was available concerning the temperature in stator bar T21.

Mr. Polich presented a responsibility assessment, which discussed the RCA and corrective actions identified therein. He stated that although the contractor is responsible for completion of the work in accordance with the contract, the plant owner is ultimately responsible for taking the proper steps and precautions to ensure the work is completed properly. He said Duke Energy Indiana’s RCA corrective actions identifies items for the Company to address and correct to prevent the future occurrence of problems and causes similar to those encountered at Cayuga Unit 1. Mr. Polich testified that Duke Energy Indiana had the responsibility to ensure its contractors working on the turbine/generator performed in accordance with specifications and established procedures to prevent leaving foreign material in the turbine generator. He concluded that Duke Energy Indiana should not be allowed to recover the higher native load fuel costs that resulted from the 2016 Outage because this outage was preventable and avoidable had the Company and Alstom conducted the turbine generator maintenance work properly, with the appropriate procedures. Mr. Polich also presented a revised estimate for the impact on native load fuel costs related to the 2016 Outage which excluded the offset for future avoided FAC costs, which he claimed is speculative.

6. **Duke Energy Indiana’s Rebuttal Testimony.**

A. **Mr. Luke.** Mr. Luke testified that Mr. Polich’s hindsight-based analysis is not appropriate. The appropriate standard, used by the Commission in reviewing a plant outage in 2009, is whether Duke Energy Indiana’s actions were reasonable and prudent. He explained that the Commission’s review should focus on whether Duke Energy Indiana operated and maintained Cayuga Unit 1 in a manner that was reasonable and prudent in light of prevailing industry standards and the information available to plant personnel at the time of the outage. Mr. Luke testified that because the Company has met that standard, it should be allowed to recover the necessary purchased power costs. Mr. Luke testified that evidence through improvement opportunities suggested in an RCA does not by itself lead to a conclusion that Duke Energy Indiana acted imprudently or unreasonably. He stated that the Company was utilizing operations and maintenance practices that are consistent with normal utility operations and industry best practices. The application of these same operation and maintenance practices have resulted in Cayuga Units 1 and 2 being among the best performers in Duke Energy’s Tier 1 coal fleet. He testified that the
Commission should not disallow fuel costs incurred due to an isolated incident, most likely caused by one instance of basic human error.

In response to Mr. Polich's statement that the new RTDs installed by Alstom were not compatible with the Cayuga Unit 1 DCS and did not report the temperature properly, Mr. Luke testified that this conclusion was drawn from the RCA rather than from any independent review or analysis. Mr. Luke stated that Alstom recommended the installation of RTDs of a different resistance type and different configuration based on the availability of the RTDs and the high risk associated with the installation of slot RTDs. He testified that it was not known whether Alstom could make them compatible with the DCS at the time of installation of these RTDs.

Mr. Luke testified that although Duke Energy Indiana personnel walked down Cayuga Unit 1 with its contractor prior to closing it to ensure no materials were left behind, unfortunately the tape was not noticed. Mr. Luke testified that based on the Company’s standard practices with monitoring contractors, Duke Energy Indiana provided adequate and prudent oversight of its contractor during the 2014 Outage. He stated that Alstom is a competent and qualified global energy company with significant related turbine and generator experience, which contributed to their selection as the preferred contractor. Mr. Luke testified that the Company has a foreign materials exclusion (“FME”) policy in place to reduce the probability of foreign materials or equipment/tools from being unaccounted for and inadvertently left in the piece of equipment upon reassembly, which all contractors are required to comply with. Mr. Luke testified that Duke Energy Indiana personnel acted in a reasonable and prudent manner in conducting a review for foreign materials. There were no foreign materials in the unit, other than the painted over piece of tape which is not a loose piece of material as it was secure, painted over, and resembled surrounding winding insulation.

Mr. Luke disagreed with Mr. Eckert’s recommendation that Duke Energy Indiana should be required to provide RCAs on major forced outages greater than 100 MW lasting more than 100 hours as part of its standard FAC. He stated that a formal RCA is a lengthy procedure that is not appropriate for all outages meeting arbitrary MW and time criteria. The Company has its own criteria for determining when an RCA is conducted, which include, but are not limited to the following: (i) when an event results in an employee or contractor Occupational Safety Health Administration recordable injury or illness; (ii) when there is a Category 1 Reportable Environmental Event such as a spill to the Waters of the U.S.; (iii) when an incident or operating practice results in equipment damage greater than $100,000; (iv) when an event results in a 50% or more loss of Maximum Dependable Capacity for more than 60 minutes; and (v) other circumstances determined by management, such as significant near misses or some Category 2 Reportable Environmental Events. Mr. Luke testified that the FAC is a summary proceeding and detailed outage reports such as a RCA could not be performed within the timeframe allotted to an FAC.

B. **Mr. Cornelius.** Mr. Cornelius identified the stator temperature monitoring equipment on Cayuga Unit 1 prior to and following the 2014 Outage. As to the embedded RTDs, he testified that although the OEM no longer recommended them, the Company decided to replace certain non-functioning embedded RTDs during the 2014 Outage at Alstom’s recommendation at the time. He testified that Alstom replaced the 10 ohm copper RTDs with 100 ohm platinum RTDs, based on availability, which prevented an extended outage beyond the original schedule. At Alstom’s recommendation, they were installed between the top stator bar and
the wedge because the top stator bar could not be removed without damaging the stator bars. Mr. Cornelius testified that plant personnel discovered the newly replaced embedded RTDs were not compatible with the DCS in 2014 when the generator was restarted and did not receive a valid signal from the four embedded RTDs. He stated that the Company tested the RTDs and determined they were sending signals to the DCS, but the DCS could not read those signals. Mr. Cornelius testified that although resolving the incompatibility with the embedded RTD inputs was included as a work order, a low priority was placed on resolving the problem because the Company did not designate embedded RTDs as critical instrumentation. He testified that there were 12 functioning gas discharge RTDs that met all OEM recommendations for monitoring which provided graphic information and indication to the DCS reflective of the operating health and condition of the machine. He stated that the new embedded RTDs were considered to be duplicative of the hydrogen core monitor and the functioning gas discharge RTDs and as such, not critical instrumentation requiring an immediate fix.

Mr. Cornelius disagreed with Mr. Polich’s statement that “critical documents associated with the placement and removal of the masking tape were missing.” He explained that Duke Energy Indiana did not routinely document the placement and removal of masking tape during an outage and had no reason to do so at the time of the 2014 Outage. He clarified that the RCA states that no documents exist which would indicate when the masking tape was placed over the ventilation tubes at the ends of the stator bars. It could have been placed there during the initial painting done by Alstom and was undetected at the time of the inspection prior to closing up the generator or, the tape may have been placed there by Alstom after the Duke Energy Indiana inspection during a final “crawl through” when additional touch-up painting might have occurred.

Mr. Cornelius disagreed with Mr. Polich’s implication that because there is no written documentation or signoff sheet reflecting evidence of a visual inspection of the exciter end of the generator, it must not have been performed. Mr. Cornelius stated that visual inspections are performed throughout generator outages and are not routinely documented. It does not mean that an inspection was not performed. Mr. Cornelius testified that he had no reason to believe that the exciter end of the generator was not inspected during the 2014 Outage.

C. Mr. Fischli. Mr. Fischli testified that Mr. Polich overlooked the fact that Duke Energy Indiana had gas discharge RTDs, in addition to the hydrogen core monitor, hydrogen gas temperature detectors, and embedded RTDs. He explained that the Company had these four types of temperature monitoring installed because it applied a belt-and-suspenders approach to monitoring internal core temperature. Mr. Fischli explained the function of each monitor and stated that Mr. Polich’s only concern was with the embedded RTDs. Mr. Fischli testified that two of the six embedded RTDs were functioning and communicating with the DCS at the time of the 2016 Outage, which Mr. Polich failed to note. Mr. Fischli disagreed with Mr. Polich’s assertion that the outage was preventable and avoidable. He stated that the primary monitoring methods in accordance with OEM recommendations, the hydrogen core monitor and gas discharge RTDs, were functional during 2014-2016 and provided no alerts to plant personnel that there was an issue on stator bar T21. Mr. Fischli stated that Mr. Polich’s testimony is incorrect as to the location of the embedded RTDs being on stator bar 21 between the bottom and top stator bars. He stated that they were actually installed on stator bar T21 between the top stator bar and the stator bar wedge, which is significantly different. Had they been installed as Mr. Polich testified the indicated temperature would have been much greater. Mr. Fischli testified that the hydrogen cooling gas flow on the stator wedge, where the RTD was actually located, had a significant impact on heat
removal in the direct vicinity of the new RTD. Mr. Fischli testified that Alstom recommended this placement of the new embedded RTDs as installation between bottom and top stator bars was not accessible without removal of the top stator bar. It was standard industry practice to place them in this location rather than removing the stator bar, which would have been more costly and resulted in a significantly longer outage. Mr. Fischli testified that since 1990 the OEM has recommended gas discharge RTDs as the primary monitoring method for directly-cooled stator winding in lieu of embedded RTDs. He stated that the Cayuga Unit 1 Generator had 12 functional gas discharge RTDs prior to and at the time of the 2016 Outage. Mr. Fischli explained why he disagreed with Mr. Polich’s estimation of the temperature in stator bar T21 at the time of the 2016 Outage, and concluded that the temperature may have been elevated, but certainly not to the extent he states. He stated that the functioning hydrogen core monitor did not detect any tagging paint compounds prior to the generator failure and visual inspection of the bar after removal did not show any gross or severe insulation discoloration, which would have been occurred with gross overheating. Mr. Fischli testified that although trend monitoring, as suggested by Mr. Polich, is a useful tool if available, in this instance there was no historical benchmark information to review for trend monitoring because the new embedded RTD was not installed at the same location as the original embedded RTD. There was no RTD in Slot 21 prior to the 2014 Outage. Mr. Fischli disagreed with Mr. Polich’s recommendation that the RCA corrective action should have required ensuring functionality of all measuring devices with OEM and the plant DCS. He stated that this is unreasonable as some instrumentation inside the generator is extremely difficult to access in order to troubleshoot or repair. Also, the value of monitoring embedded RTDs, which are no longer recommended by the OEM, does not justify the extensive disassembly required for repair. He testified that prudence requires evaluating the benefit of information provided and the cost to repair the equipment, and deciding whether it is cost-justified to initiate the repair. Ensuring the functionality of all measuring devices, as suggested by Mr. Polich, would significantly increase the cost to the customer.

D. Mr. Burnside. Mr. Burnside testified that it would not have been possible to correctly utilize PROMOD in his analysis of the impact of the 2016 Outage, as suggested by Mr. Phillips. He stated that the Company does not have access to generator and transmission data of competing utilities in the MISO system. LMPs at individual nodes are influenced by generation activity and transmission constraints outside of the Duke Energy Indiana system. Without this information, PROMOD cannot perform an after the fact analysis. Mr. Burnside testified that the approach he utilized, as explained in his direct testimony, was reasonable. Mr. Burnside disagreed with Mr. Phillips recommendation that future 2022 FAC related avoided costs resulting from performing a full rewind on Cayuga Unit 1 in 2016 should not be included in the analysis. He stated that the need for a full stator rewind is not speculative and was already scheduled to be performed during a 2022 planned outage. Utilizing Mr. Cornelius’ estimation that rewinding the stator in 2016 will reduce the 2022 outage by two to four weeks, it was assumed in the analysis that the outage was reduced by approximately three weeks. Mr. Burnside testified that contrary to Mr. Phillips” testimony that the Company could choose to retire Cayuga Unit 1 prior to 2022, the Company’s Integrated Resource Plan does not call for Cayuga Unit 1 to retire before the year 2035, which was the extent of the study period. Mr. Burnside also testified that the stator rewind scheduled for 2022 was not dependent on a rate case, but rather the maintenance needs of the unit.
7. **Settlement Testimony.**

A. **Duke Energy Indiana.** Mr. Luke testified that the Settlement Agreement is the product of extended negotiations among the Settling Parties, conducted at an arms' length basis, and is intended to resolve all disputes, claims and issues that could have been raised in the proceeding. Duke Energy Indiana is not admitting any fault or imprudence. He testified that the Settlement Agreement, attached as Exhibit 9-A, provides that Duke Energy Indiana will: (1) reimburse customers $3 million to offset the purchase power costs during the 2016 Outage; (2) file in subsequent FAC proceedings any RCA performed during the normal course of business for outages of units of 100 MW or more lasting more than 100 hours, in accordance with (a) the reporting requirement imposed in the Final Order in Cause No. 38707 FAC 90; and (b) Duke Energy Indiana’s standard protocol for determining when to conduct an RCA in effect at the time of the outage; (3) calculate an estimate of the impact on native load fuel cost for major forced outages on units larger than 100 MW and that last more than 60 days in duration, which would be included in Mr. Burnside’s workpapers; and (4) reimburse Nucor and Industrial Group for their reasonably incurred legal expenses and attorneys’ fees up to $300,000. These funds will not be borne by Duke Energy Indiana’s customers. Mr. Luke testified that any RCA provided under the terms of the settlement will be provided in the FAC proceeding immediately following the completion of the RCA. He testified that the Settlement Agreement does not impose an obligation to perform an RCA that would otherwise not be performed.

Ms. Sieferman, Director Rates and Regulatory Planning for Duke Energy Indiana, testified that the $3 million credit to customers will be refunded through the next FAC proceeding initiated following approval of the Settlement Agreement. She explained that the credit will be allocated between retail and native wholesale jurisdictional sales using the same methodology as is used for the fuel costs typically included in the FAC. She testified that the reasonable attorney’s fees and expenses agreed to under the Settlement Agreement will be paid by Duke Energy Indiana shareholders and will not flow through to customers. Ms. Sieferman testified that the Settlement Agreement provides a reasonable resolution to the potential issues that could have been raised in this proceeding.

B. **Industrial Group.** Mr. Phillips stated that the Settlement Agreement provides a reasonable resolution to the issues presented in this case and brings substantial value to ratepayers. He testified that the $3 million credit to customers through the next FAC represents a reasonable resolution of Duke Energy Indiana’s responsibility for the purchase power costs due to the 2016 Outage. He testified that the enhanced reporting requirements under the Settlement Agreement aid the consumer parties and the Commission in understanding outage causations and economic impacts. Mr. Phillips testified that, in his opinion, the Settlement Agreement is reasonable and in the public interest, and recommended that the Commission approve the Settlement Agreement.

C. **Nucor.** Mr. Polich testified that he agreed with Duke Energy Indiana’s RCA on the cause and description of how stator bar T21 failed, resulting in the 2016 Outage. He testified that the Settlement Agreement is the product of lengthy, arms-length negotiations and Nucor joins in the Settling Parties’ request for its approval. Mr. Polich testified that the Settlement Agreement is a complete and interrelated package that is intended to resolve all issues between the Settling Parties in this proceeding.

A. Settlement Agreement. Settlements presented to the Commission are not ordinary contracts between private parties. See United States Gypsum, Inc. v. Indiana Gas Co., 735 N.E.2d 790, 803 (Ind. 2000). Any settlement agreement that is approved by the Commission “loses its status as a strictly private contract and takes on a public interest gloss.” Id. (quoting Citizens Action Coalition v. PSI Energy, Inc., 664 N.E.2d 401, 406 (Ind. Ct. App. 1996)). Thus, the Commission “may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement.” Citizens Action Coalition, 664 N.E.2d at 406.

Further, any Commission decision, ruling, or order, including the approval of a settlement, must be supported by specific findings of fact and sufficient evidence. United States Gypsum, 735 N.E.2d at 795 (citing Citizens Action Coalition of Ind., Inc. v. Public Service of Ind., Inc., 582 N.E.2d 330, 331 (Ind. 1991)). The Commission’s own procedural rules require that settlements be supported by probative evidence. 170 IAC 1-1.1-17(d). Therefore, before the Commission can approve the Settlement Agreement, we must determine whether the evidence in this Cause sufficiently supports the conclusions that the Settlement Agreement is reasonable, just, and consistent with the purpose of Indiana Code ch. 8-1-2, and that such agreement serves the public interest.

This subdocket was initiated in FAC 111, in which we stated:

The Commission must base its decisions solely on the evidentiary record and when appropriate may seek supplemental evidence to foster reasoned decision-making. At times the summary nature of proceedings with statutory time constraints such as the FAC do not lend themselves to such record development. Applicant generally identified the major outage and repair of Cayuga Unit 1. Nucor and the OUCC, however, explored the outage and related impact on Applicant’s fuel cost recovery at issue in this expedited FAC proceeding and entered additional facts concerning the outage and repair of Cayuga Unit 1 into the record which raised reasonable questions regarding the root cause of the outage. Applicant has not yet refuted nor supported its position sufficiently, nor has it provided any scale to the potential financial impact of it, to allow a final decision on the prudency of Applicant’s actions regarding the outage and therefore the reasonableness of recovery for any incremental fuel costs associated with it. We agree with Nucor based on the facts in this circumstance that such a detailed review is best accomplished outside the statutory time constraints of the FAC summary proceeding. Thus, we find that the provision, review, and inquiry of such information is best served by the Commission’s initiation of a subdocket proceeding focused on the issue. Therefore, the Commission grants Nucor’s Motion for Subdocket.

Duke Energy Indiana, 38707 FAC 111, at 8 (IURC Apr. 26, 2017). Through the subdocket, the parties had the opportunity to present additional evidence concerning the 2016 Outage and repairs, the 2014 maintenance, and the financial impact of the incremental fuel costs associated with the 2016 Outage. The record demonstrated that the Cayuga Unit 1 2016 Outage was ultimately caused by masking tape that was not removed during planned outage maintenance by Alstom, a Duke
Energy Indiana subcontractor, in 2014. The record also demonstrated that as a result of the Cayuga Unit 1 2016 Outage, Duke Energy Indiana incurred more than $6 million in purchased power charges that otherwise would not have occurred.

To resolve these issues, the Settling Parties presented a Settlement Agreement to the Commission for approval. The Settlement Agreement provides that Duke Energy Indiana will refund $3 million to customers through the FAC process, that Duke Energy Indiana will provide additional information through the FAC process concerning future outages of units 100 MW or larger, lasting 60 days or more, and that Duke Energy Indiana shareholders will reimburse the Industrial Group and Nucor for reasonable attorney fees and legal expenses up to $300,000. Under the terms of the Settlement Agreement, resolution of this Cause does not represent an admission of fault on behalf of Duke Energy Indiana for the 2016 Outage.

Having reviewed all of the evidence in this proceeding, we find that the Settlement Agreement represents a reasonable resolution to this proceeding, and we approve the Settlement Agreement in its entirety. The Settlement Agreement resolves the contested assignment of the ultimate responsibility for the cause of the outage, the immediate customer refund for a significant portion of the cost of the outage, and the enhanced transparency and timely process should significant outages occur in the future provide support for this finding. The Settling Parties agree that the Settlement Agreement should not be used as precedent in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce its terms. Consequently, with regard to future citation of the Settlement Agreement, we find our approval herein should be construed in a manner consistent with our finding in Richmond Power & Light, Cause No. 40434, 1997 Ind. PUC LEXIS 459 at *19-22 (IURC March 19, 1997).

B. Confidentiality. Duke Energy Indiana filed motions for protection of confidential and propriety information on July 20, 2017, and September 29, 2017. In the motions and supporting affidavits, Duke Energy Indiana demonstrated a need for confidential treatment for: (1) certain sensitive and detailed cost information associated with its Cayuga Station Generating Units and the 2014 and 2016 Outages, including vendor pricing; (2) Cayuga outage data, heat rate, and variable cost information used in calculating the impact of the 2016 outage on native load fuel costs; (3) sensitive and detailed information provided to Duke Energy Indiana by its contractors regarding Cayuga Unit 1; and (4) confidential terms and conditions of Duke Energy Indiana’s vendor contracts. On August 1, 2017, and October 10, 2017, respectively, the Presiding Officers made preliminary determinations that such information should be subject to confidential procedures. We find that all such information is confidential pursuant to Ind. Code § 5-14-3-4 and Ind. Code § 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.

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

1. The Settlement Agreement, which is attached to this Order, is approved, and this subdocket is closed.

2. Duke Energy Indiana shall refund $3 million to customers through its next FAC proceeding initiated following the date of this Order.
3. Duke Energy Indiana shall, with its prefiled testimony in subsequent FAC proceedings, file any RCA performed in accordance with the report requirement imposed in the Final Order in Cause No. 38707 FAC 90 and its standard protocol for determining when to conduct an RCA.

4. In subsequent FAC proceedings, Duke Energy Indiana shall calculate an estimate of the impact on native load fuel cost for major forced outages on units larger than 100 MW and that last more than 60 days in duration.

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

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

APPROVED: APR 11 2018

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

Mary M. Becerra
Secretary of the Commission
STIPULATION AND SETTLEMENT AGREEMENT
JURC CAUSE NO. 38707 FAC 111-S1

Introduction
This Stipulation and Settlement Agreement ("Agreement"), dated as of the 16th day of January, 2018, is made and entered into by and between the duly authorized representatives of Duke Energy Indiana, LLC (and its successors) and Nucor Steel-Indiana, the Duke Energy Indiana Industrial Group, and the Indiana Office of Utility Consumer Counselor ("collectively "Settling Parties") solely for purposes of compromise and settlement. The Settling Parties agree that this Agreement resolves all disputes, claims, and issues from the Indiana Utility Regulatory Commission ("Commission") proceeding in Cause Nos. 38707 FAC 111 and 38707 FAC 111-S1.

Settlement Terms

1. Refund to Customers. Duke Energy Indiana will credit $3,000,000 to offset the purchased power costs during the Cayuga outage which are at issue in this proceeding. This amount will be refunded, following approval of this Agreement, through the next FAC. This amount represents the entire amount of the customer credit to resolve this proceeding and does not represent an admission of fault on behalf of Duke Energy Indiana, LLC.

2. Root Cause Analysis. In subsequent fuel clause proceedings, Duke Energy Indiana agrees to file, with its profiled testimony, any Root Cause Analysis ("RCA") performed in accordance with:
   a. the reporting requirement imposed in the Final Order in Cause No. 38707 FAC 901; and
   b. Duke Energy Indiana's standard protocol for determining when to conduct an RCA in effect at the time of the outage.2

Duke commits to providing any such RCA in the fuel clause proceeding immediately following the completion of the RCA.

3. Estimate of Native Load Fuel Costs. In subsequent fuel clause proceedings, Duke Energy Indiana agrees to calculate an estimate of the impact on native load fuel cost for major forced outages on units larger than 100 MW and that last more than two months (60 days) in duration. Duke Energy Indiana agrees to include this information in its profiled workpapers, and shall reference such workpapers in its profiled testimony.

4. Attorney's Fees. Duke Energy Indiana agrees to reimburse Nucor Steel-Indiana and the Duke Energy Indiana Industrial Group for their reasonably incurred legal expenses and attorneys' fees up to $300,000, subject to verification of actual expenses and fees. Fees and expenses due under this

1 See, JURC Final Order in Cause No. 38707 FAC 90, p. 12 (reporting required for outages of units of 100 MW or more lasting more than 100 hours).
provision shall be received within 30 days after all reviews and appeals of a final order in this proceeding have been exhausted. This amount will be paid by Duke Energy Indiana shareholders and will not flow through to customers.

5. **Settlement Resolves all Issues in this Proceeding.** This Agreement is a complete and interrelated package that is intended to resolve all issues between the Settling Parties as to Duke Energy Indiana's filing in Cause No. 38707 FAC 111 S1.

6. **Other.**

   A. The Settling Parties agree to notify the Commission of this settlement in a timely manner and will jointly move the Commission for approval of the Agreement in its entirety.

   B. The Settling Parties agree to support the terms of this Agreement in good faith and further agree not to take any positions adverse to or inconsistent with the Agreement or any adverse positions against each other with respect to the Agreement before any appellate courts, or on rehearing, reconsideration, remand or subsequent or additional related proceedings before the Commission. Duke Energy Indiana, the Duke Energy Indiana Industrial Group shall, and the OUC and Nucor Steel-Indiana may, present testimony that contains substantial evidence before the Commission in support of the Agreement.

   C. If the Order of the Commission in this proceeding modifies or conditions this Agreement, only the Settling Parties to this Agreement may decide to accept or reject such modification or condition. If the Settling Parties do not unaniously accept the modified Agreement, this Agreement shall become void in its entirety and have no effect.

   D. The Settling Parties shall remain bound by the terms of this Agreement and shall continue to support or not oppose all the terms of the Agreement on appeal, remand, reconsideration, etc., even if the Commission rejects the Agreement. However, in the event that the Agreement is rejected by the Commission and such rejection is ultimately upheld on rehearing, reconsideration, and/or appeal, at the point when all such proceedings and appeals are complete, this Agreement shall become void and of no further effect (except for provisions which have already been fully implemented or that are explicitly stated herein to survive termination/voiding).

   E. The positions taken by the Settling Parties in this Agreement shall not be deemed to be admissions by any of the Settling Parties and shall not be used as precedent, except as necessary to implement the terms of this Agreement. This provision shall survive termination/voiding of this Agreement.

   F. It is understood that this Agreement is reflective of a good faith negotiated settlement and neither the making of the Agreement nor any of its provisions shall constitute an admission by any Settling Party in this or any other litigation or proceeding except as necessary to implement or enforce this Agreement. It is also understood that each and every term of the Agreement is in consideration and support of each and every other term.
G. The communications and discussions during the negotiations and conferences and any materials produced and exchanged concerning this Agreement all relate to offers of settlement and shall be privileged and confidential, without prejudice to the position of any Settling Party, and are not to be used in any manner in connection with any other proceeding or otherwise. This provision shall survive termination/voiding of this Agreement.

H. The undersigned Settling Parties have represented and agreed that they are fully authorized to execute the Agreement on behalf of their designated clients, and their successors and assigns, who will be bound thereby.

I. This Agreement may be executed in two (2) or more counterparts, each of which shall be deemed an original, but all of which together shall constitute one and the same instrument.

ACCEPTED AND AGREED TO THIS 16th day of January 2018.

[Signature pages to follow]
For Duke Energy Indiana, LLC

Melody Birmingham-Byrd, President
Duke Energy Indiana, LLC

Melanie D. Price
Associate General Counsel
Duke Energy Indiana, LLC

[This is a signature page for the Stipulation and Settlement Agreement in Cause No. 38707 FAC 111 SI before the Indiana Utility Regulatory Commission. Remainder of page intentionally left blank.]
For the Indiana Office of Utility Consumer Counselor:

William Fine, Consumer Counselor  
Indiana Office of Utility Consumer Counselor  

Randall C. Helmen, Chief Deputy Consumer Counselor  
Indiana Office of Utility Consumer Counselor

[This is a signature page for the Stipulation and Settlement Agreement in Cause No. 38707 FAC 111-S1 before the Indiana Utility Regulatory Commission. Remainder of page intentionally left blank.]
For Nucor Steel - Indiana:

Anne Becker
Lewis & Kappes, P.C.

[This is a signature page for the Stipulation and Settlement Agreement in Cause No. 38707 FAC 111-S1 before the Indiana Utility Regulatory Commission. Remainder of page intentionally left blank.]
For the Duke Energy Indiana Industrial Group:

Signature

Aaron A. Schmoll
Lewis & Kappes, P.C.

[This is a signature page for the Stipulation and Settlement Agreement in Cause No. 38707 FAC 111-S1 before the Indiana Utility Regulatory Commission. Remainder of page intentionally left blank.]