ORIGINAL

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

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

SUBDOCKET FOR REVIEW OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA'S 2021 EXTENDED FORCED OUTAGE AT EAGLE VALLEY AND ITS RELATED IMPACT ON FUEL PROCUREMENT AND FUEL COSTS.))))))

CAUSE NO. 38703 FAC 133 S1

APPROVED: JAN 18 2023

ORDER OF THE COMMISSION

Presiding Officers:
James E. Huston, Chairman
Stefanie N. Krevda, Commissioner
Loraine L. Seyfried, Chief Administrative Law Judge

On November 24, 2021, by its Order in Cause No. 38703 FAC 133, the Indiana Utility Regulatory Commission ("Commission") created this subdocket proceeding to examine the impact of the Eagle Valley Combined-Cycle Gas Turbine ("CCGT") extended forced outage on the fuel procurement and fuel costs of Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana" or "Applicant").

On December 14, 2021, counsel for Citizens Action Coalition of Indiana, Inc. ("CAC"), an intervenor in Cause No. 38703 FAC 133, filed an appearance in this Cause.

On January 7, 2022, AES Indiana filed an unopposed motion to extend the time to file an agreed procedural schedule and committed to file a status report, which the Presiding Officers granted by Docket Entry on January 10, 2022. The Presiding Officers further required AES Indiana to file a Status Report on the Eagle Valley repairs, Root Cause Analysis ("RCA") status, and timeline for moving forward by February 9, 2022. AES Indiana submitted the Status Report on February 9, 2022.

On February 18, 2022, by Docket Entry, the Presiding Officers required AES Indiana to file updated status reports on the 1st and 15th of each month beginning on March 1, 2022, until otherwise notified. AES Indiana filed status reports on March 1, March 15, and March 24, 2022.

On March 31, 2022, AES Indiana filed a Stipulation and Agreement as to Procedural Schedule and Request to Terminate Status Reports. On April 11, 2022, the Presiding Officers, by Docket Entry, established a procedural schedule, scheduled a Technical Conference, and granted AES Indiana's request to terminate status reports. In response, on April 14, 2022, AES Indiana filed a Notice Regarding the RCA.

On April 27, 2022, the AESI Industrial Group ("Industrial Group") filed a Petition to Intervene which was granted by Docket Entry on May 9, 2022.

On May 31, 2022, AES Indiana filed the direct testimony, attachments, and workpapers for the following witnesses:

- John Bigalbal, Chief Operating Officer, US Conventional Generation, AES US Services, LLC;
- Alexander K. Halter, Operations Manager, Eagle Valley, AES Indiana;
- Holcombe Baird, Senior Reliability Consultant and RCA Facilitator, Reliability Center, Inc. ("RCI");
- David Jackson, Director, Commercial Operations, AES US Services, LLC; and
- Natalie Herr Coklow, Regulatory Accounting Manager, AES US Services, LLC.[1]

The Commission conducted a Technical Conference on June 6, 2022, at 1:30 p.m. in Room 222 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana.

On August 29, 2022, the Indiana Office of Utility Consumer Counselor ("OUCC") filed its direct testimony of Michael D. Eckert, Director of the OUCC's Electric Division, and consumer comments. The same day, the Industrial Group filed the direct testimony and attachments of Michael P. Gorman, a Managing Principal with Brubaker & Associates, Inc. and the CAC filed the direct testimony Ben Inskeep, CAC's Program Director.

On October 7, 2022 AES Indiana prefiled rebuttal testimony of Mr. Bigalbal, Mr. Halter, Mr. Jackson, Ms. Coklow, and the following witnesses:

- G. Aaron Cooper, Chief Commercial Officer, US Utilities, AES US Services, LLC; and
- Ralph N. Zarumba, Managing Director, Black & Veatch Global Advisory.

On October 25, 2022, AES Indiana, the OUCC, the CAC, and the Industrial Group filed an Unopposed Joint Motion for Leave to File Settlement Agreement and Request for Settlement Hearing ("October 25 Joint Motion"). The October 25 Joint Motion informed the Commission the above parties had reached settlement. The formal written Stipulation and Settlement Agreement ("Settlement Agreement") was also filed on October 25, 2022.

By docket entry dated October 26, 2022, the Presiding Officers granted the October 25 Joint Motion and revised the procedural schedule.

On November 4, 2022, AES Indiana filed the settlement testimony of Chad A. Rogers, Director Regulatory Affairs, supporting the Settlement Agreement reached among all the parties. The same day, the OUCC and the Industrial Group filed supporting settlement testimony of Mr. Eckert and Mr. Gorman, respectively.

An Evidentiary Hearing was held at 2:30 p.m. on November 21, 2022, in Room 222, PNC Center, 101 West Washington Street, Indianapolis, Indiana. At the hearing, AES Indiana, the OUCC, and the Industrial Group, appeared and participated by counsel. In accordance with a Notice filed November 18, 2022, CAC counsel was not able to appear at the hearing and the parties

[1] A revision to Ms. Coklow's testimony was prefiled on October 14, 2022.

stipulated to the admittance of the CAC's evidence. The testimony and exhibits of AES Indiana, the OUCC, the Industrial Group, and the CAC were admitted without objection.

Based upon applicable law and the evidence of record, the Commission finds as follows:

1. Notice and Jurisdiction. Notice of the evidentiary hearing was given and published by the Commission as required by law. AES Indiana is a "public utility" as that term is defined in Ind. Code § 8-1-2-1(a). Under Ind. Code § 8-1-2-42, the Commission has jurisdiction over changes to AES Indiana's fuel cost charge. Therefore, the Commission has jurisdiction over Applicant and the subject matter of this subdocket.

2. AES Indiana's Characteristics. AES Indiana is an electric generating utility and a corporation organized and existing under the laws of Indiana with its principal office in Indianapolis, Indiana. AES Indiana is engaged in rendering electric public utility service in Indiana. AES Indiana owns and operates plants and equipment within Indiana used for the production, transmission, delivery, and furnishing of electric service to the public.

3. Background. The Eagle Valley CCGT plant ("Eagle Valley") is a 671 MW gas-fired combined cycle gas turbine facility located in Morgan County, Indiana. The plant consists of two GE 7FA.05 gas turbines, associated Nooter Eriksen heat recovery steam generators, and a Toshiba steam turbine. Eagle Valley commenced commercial operations on April 28, 2018, which is the date AES Indiana took ownership and control of the CCGT. This proceeding addresses the Eagle Valley CCGT forced outage that occurred April 25, 2021 to March 18, 2022 ("Outage").

4. AES Indiana's Case-in-Chief.

A. Overview of Eagle Valley. Mr. Bigalbal provided an overview of Eagle Valley. He testified Eagle Valley has had two years of solid performance, reliably operating as a baseload unit in 2019 and 2020. Mr. Bigalbal explained that Eagle Valley is a modern plant with automated controls. The control systems are supposed to be designed to operate the plant automatically and perform the necessary startup and shutdown sequences as well as ramping up and down. He explained the automated control systems should monitor processes, alarm if there is a deviation in the expected sequence or process, and perform trip functions for significant deviations to provide safety for personnel and to protect the equipment. Mr. Bigalbal said some portions of the control systems can be manually overridden by operator intervention; manually overriding the automated controls should not defeat the protection systems, alarms, and trips. Mr. Bigalbal testified that the control system should ensure all systems are properly lined up and in a state of condition that allow for proper operation. He said these conditions are called permissives and testified that in the event all permissives are not met, the control system should not allow a sequence to advance, or a process or piece of equipment to be put into service. He said AES Indiana and its personnel reasonably approach work with the expectation that the plant's control systems purchased from qualified sources have sound logic and design and added that operators are not expected to completely understand the complex engineering logic of these control systems.

B. Overview of Eagle Valley CCGT Steam Handling System. A pictorial overview of the Steam Handling System was provided in Applicant's Exhibit 2-C, Confidential Attachment AKH-1. Mr. Halter explained that when the steam turbine is online and out of startup mode, the bypass valves are closed. He said the main steam, also called high pressure ("HP") steam, is the highest pressure steam. The main steam flows through the HP steam turbine, exits through the HP Turbine Exhaust pipe, and is now called cold reheat ("CRH") steam. Mr. Halter explained this steam is sent back to the heat recovery steam generator ("HRSG") and is reheated into what is called hot reheat ("HRH") steam. The HRH steam flows through the intermediate pressure ("IP") steam turbine, through the low pressure ("LP") steam turbine, and then condenses in the condenser. Mr. Halter said the LP steam system provides supplemental steam at the IP exhaust prior to entering the LP steam turbine. He said the bypass system is used when the gas turbine is running and the steam turbine is not running or is in startup. Mr. Halter said the HP bypass valve controls the pressure of the main steam and bypasses the HP turbine directly into the CRH piping. He explained the IP bypass valve controls the pressure of the HRH steam, which directly reduces the pressure of the CRH steam, and bypasses the IP and LP turbine directly into the condenser.

C. <u>Overview of Cold-Start Process</u>. As explained by Mr. Halter, a cold-start for the Steam Turbine Generator 1 ("STG1") is when it has been shut down for over 72 hours. A cold-start requires a long startup sequence to minimize temperature ramp up and thermal stress on the steam turbine. Mr. Halter testified that prior to the Outage, STG1 experienced five cold-starts since commercial operation began in April 2018.

D. <u>Controls Overview</u>. Mr. Halter explained that a control narrative is the written description of what each system is, the major components of the system, and how the components operate. He said the relevant control narratives were written by Chicago Bridge & Iron ("CB&I"), the engineering, procurement, and construction ("EPC") Contractor for the Eagle Valley CCGT. He said the control narratives are written for the systems designed by CB&I and need to meet the design criteria of the original equipment manufacturers ("OEMs"). Mr. Halter testified that a controls engineer uses the control narrative to build the Distributed Control Systems ("DCS") logic to operate the components per the control narrative description. He said Eagle Valley CCGT has three control systems: General Electric ("GE") Mark VIe, Toshiba Microprocessor Aided Power ("TOSMAP"), and Emerson Ovation. The GE Mark VIe control system controls the gas turbines and gas turbine generators. The Toshiba TOSMAP control system controls the steam turbine and steam turbine generator. And, the Emerson Ovation system controls the generation output and the remainder of the plant, which includes the HRSG and steam handling system.

E. <u>Eagle Valley CCGT Forced Outage</u>.

1. <u>Incident 1A</u>. Mr. Bigalbal explained Incident 1A occurred on April 25, 2021, when the unit was returning from its planned maintenance outage and began start up. He said during start up, the STG1 experienced an issue with the 52G Breaker (generator breaker) that prohibited it from synchronizing with the grid. He said the 52G Breaker should have closed to allow the unit to synchronize (or connect) to the grid but the control system was showing the 52G Breaker open in one location and closed in another. He testified that when troubleshooting did not resolve the issue, a decision was made to shut down the unit for the night so that troubleshooting could resume the next day. He said during the unit coast down, the 86G1 and 86G2 lockout relays were activated, which should have opened the 41E field breaker ("41E Breaker"). After the turbine

completed its coast down and was placed on turning gear, the 86G relays were reset by a technician. Fourteen minutes after the 86G relays were reset, the 86ET lockout relay tripped.

Mr. Bigalbal explained the 41E Breaker, which isolates and protects the generator, did not open as expected, but remained closed. He said because the 41E Breaker was closed and not opened by activation of the 86G relays, the Automatic Voltage Regulator ("AVR"), which had been previously shut down by the 86G relay activation, was put into service. Mr. Bigalbal explained that troubleshooting and subsequent testing determined that a short to ground in the field had occurred.

Mr. Bigalbal described the damage assessment and associated actions taken by AES Indiana immediately following Incident 1A. Mr. Bigalbal discussed the alternatives to the repair of the generator and the steps taken by AES Indiana to mitigate the duration of Incident 1A. He stated the repairs to the steam turbine's generator were completed the first week of November 2021, the plant commenced testing and startup, and the incident completed on November 10, 2021.

Mr. Bigalbal testified the estimated non-fuel operating costs and capital expenditures for Incident 1A totaled $8,882,797 and explained that because these costs are not recoverable through the FAC process, they are not part of the FAC applications that were approved on an interim basis subject to true-up pending the outcome of this subdocket. He said a portion of the costs will be covered by insurance after the $5,000,000 deductible and added Applicant expects to receive an insurance settlement of approximately $1,000,000 for Incident 1A. Mr. Bigalbal stated Applicant is also working with outside counsel to assess and pursue potential warranty and claims against the EPC Contractor and OEMs.

2. <u>Incident 1B</u>. Mr. Halter testified that Incident 1B occurred on November 10, 2021 during a cold restart of the Eagle Valley CCGT when the unit returned from Incident 1A. He said that during the restart, Toshiba provided a controls system engineer for startup and troubleshooting support. He explained that on November 8, 2021, Gas Turbine 2 ("GT2") was successfully started and connected to the grid. He said, thereafter, an attempt to start the STG1 failed due to a communications issue inside the Toshiba TOSMAP responsible for providing the communication between the field sensors and the control processors. He said while troubleshooting was underway, GT2 output was increased to get GT2 into Dry Low NOx Mode to allow the Selective Catalytic Reduction system to be put into service and reduce NOx emissions.

Mr. Halter testified that on November 10, 2021, the TOSMAP issues were resolved, and the STG1 startup sequence was initiated. He said the heat soaks and speed ramp ups were completed and the unit reached Full Speed, No Load ("FSNL") operation; however, this effort was delayed by breaker issues and a need to determine why the 41E Breaker failed to close. He said troubleshooting efforts found the problem resulted from a failed relay on a printed circuit board in the AVR controller. Mr. Halter testified that once the printed circuit board was replaced, the 52G Breaker failed to close, leaving the generator unable to connect to the power grid. He stated that while troubleshooting the issue with the 52G Breaker, the sound of an explosion was heard in the control room. He said both units, the STG1 and GT2, were tripped manually, and the operators proceeded with a plant shutdown and added that a field visual inspection found a rupture in the south leg of the HP exhaust pipe.

Mr. Halter also testified that Kiewit, Stag Control, and AES Indiana control experts performed a comprehensive review of the control narratives and control logic. He said after the reviews were completed, Kiewit and AES Indiana developed the necessary modifications to the control narratives and logic. Emerson was hired to implement the control logic change and Technical Training Professionals was hired to perform training in association with the control system changes. He said Kiewit provided a commissioning team to oversee the startup of the plant.

Mr. Halter discussed the repair work following Incident 1B. He also discussed the steps taken by AES Indiana to mitigate the duration of Incident 1B and the repair options that were investigated. Mr. Halter said the repairs were completed by March 11, 2022, the plant was successfully restarted and achieved full load on March 14, and the required Midcontinent Independent System Operator ("MISO") capacity test was completed with both gas turbines and steam turbine at full load on March 15. He said Eagle Valley then operated with one gas turbine and the steam turbine from March 15 to March 18, 2022, to allow for GT2 and HRSG2 to cool while additional tuning changes were made and to test the gas turbine during a cold startup. He said the facility was released for full load dispatch on March 18, 2022, and the facility is operating efficiently with the same heat rate as prior to the repairs.

Mr. Halter testified the estimated non-fuel operating costs and capital expenditures for Incident 1B totaled $13,619,070 and explained that because these costs are not recoverable through the FAC process, they are not part of the FAC applications that were approved on an interim basis subject to true-up pending the outcome of this subdocket.

F. **<u>Control Logic and Troubleshooting Overview</u>.** Mr. Halter discussed the importance of control logic, presented a technical specifications excerpt from the turnkey EPC contract, which was included as Applicant's Exhibit 2-C, Confidential Attachment AKH-2(C), and discussed the necessity for troubleshooting. He discussed the function of automated controls and said manual intervention should not defeat the automated protection systems and trips.

G. **<u>Comprehensive Controls Review</u>.** Mr. Halter testified that following Incident 1B, CCGT design specialists and control system experts reviewed the control systems, narratives, and logic for critical systems and equipment. He said each control narrative was reviewed to determine if the control design is correct for controlling its respective system and then the DCS logic was reviewed to determine if the logic meets the control narrative. He said the review was undertaken because the Outage was caused by two-high impact incidents during start-ups in 2021 and system controls failed to protect critical equipment in both events. He said when Incident 1B occurred, it was evident there was a controls failure that allowed for the STG1 to operate until failure. Mr. Halter said Applicant's EPC contract technical specifications required control systems that will trip equipment to protect personnel and equipment prior to failure.

Mr. Halter elaborated on the control logic issues in the DCS as a main contributor to Incident 1B. He said in Incident 1B, the control systems did not have an automatic trip as protection for the high temperature condition, contrary to the practice to have a high temperature alarm level, and, if not effectively acted upon, have a high, high temperature trip level to protect the unit.

As summarized in Table AKH-2 of Applicant's Exhibit 2-C, Kiewit's review found discrepancies in the control narratives and DCS logic. Mr. Halter said there were discrepancies in the control narratives where they incorrectly described the systems, the instrumentation identified for control was incorrect, the permissives (conditions that must be met to safely startup equipment) and/or trips were incorrect, and the control narrative did not meet the OEM's design criteria. He testified there were discrepancies found in the DCS logic where the DCS logic had incorrect and/or missing permissives, incorrect and/or missing trips, incorrect instrumentation being used for control, and did not follow the control narrative. Mr. Halter testified that the recommendations from the controls review have been implemented.

H. RCA. AES Indiana witnesses Baird, Bigalbal, and Halter discussed the RCA. Mr. Bigalbal and Mr. Baird explained a RCA seeks to identify factors, that when addressed, would have the highest probability of preventing a reoccurrence. Mr. Bigalbal said the RCA is an essential component to continuous improvement and its purpose is distinct from a review of whether Applicant has acted imprudently, i.e., without caring for the consequences of an action—a conscious disregard for sound utility practice. Mr. Baird explained how RCI's RCA process is implemented, described the RCI PROACT® Logic Tree to conduct RCAs, and explained his role in the RCA process.

1. Incident 1A. Mr. Bigalbal said the Incident 1A RCA determined that STG1 failed to synchronize with the grid because the 52 Breaker did not close; the 52 Breaker did not close due to a disconnected wire in the generator breaker cabinet; and troubleshooting efforts to remedy the 52 Breaker issue discovered an error in the as-built wiring schematics. Mr. Bigalbal also discussed the confidential findings in the RCA regarding the cause of the field short. He said the Incident 1A RCA found that when the 86G relays were reset, with the 41E Breaker closed, the AVR energized the field and there was not enough hydrogen flow to cool the excited field on turning gear since the amount of circulation is driven by the rotor speed.

Mr. Bigalbal elaborated on the underlying physical and latent factors identified in the Incident 1A RCA. He said the RCA was unable to conclusively determine how the wire was disconnected. He said there are several ways wires may be disconnected from a terminal strip including intentional, accidental, or without intervention, and discussed the extensive hypothesis and reenactment work performed as part of the RCA. He said had this wire not been disconnected, Incident 1A would not have occurred.

Mr. Bigalbal also elaborated on what happened with respect to the AVR that sent excitation current to the field while the unit was on turning gear and said this was unexpected since the Steam Turbine Generator was tripped. He said the field breaker of a generator should not open if the generator is synchronized to the grid. He concluded that the 52GX relay could not be RESET and provided false indication to the 41E Breaker open command circuit. He said this logic is called into question and added Applicant is reviewing this logic with Toshiba.

Mr. Bigalbal said the RCA recommended corrective actions are complete: re-terminate the disconnected wire in the generator breaker (52G Breaker) cabinet using OEM recommended standards including terminal ring lugs; clean up wiring in the field breaker (41E Breaker) cabinets to remove wiring with exposed conductors and other identified deficiencies; establish 86 series lockout relay reset Standard Operating Procedure ("SOP") in accordance with industry best practices; and establish operational pre-startup step to confirm agreement in status indicators for the generator (52G Breaker) and field (41E Breaker) breakers. He said the RCA also recommended the following: (1) conducting an engineering review of the field breaker (41E Breaker) open signal circuit hardwired interlocks and control system interlocks for effective redundancy as well as compliance with Institute of Electrical and Electronics Engineers and Electric Power Research Institute standards (completed); (2) OEM review of the incident details to consider installing provisions in the AVR logic to detect and alert operators of a discrepancy in the generator (52G Breaker) and field (41E Breaker) breaker status (underway with Toshiba). Applicant has designed and implemented logic to trip the 5A Breaker (Excitation Transformer Breaker) in the event the lockout relays activate and the 41E Breaker does not open after a short period of time; (3) perform an audit of all wiring diagrams for accuracy of generator protection systems and document the findings and develop a plan to correct discrepancies (this inspection and a redline markup of the drawings are complete, and the drawings are being updated); (4) implement a training program for operators and technicians specifically on the design and operation of the generator protection system, including processes for operating breakers and resetting lockout relays (complete).

2. <u>Incident 1B</u>. Mr. Halter testified that the Incident 1B RCA analysis identified the potential issues in the DCS as a main contributor to Incident 1B and experts were hired to separately assess and correct these matters. He said the Incident 1B RCA investigated why the CRH piping ruptured and why the HP Steam components were damaged (was it pressure, was it temperature). He said this investigation determined that the rupture and damage was due to high HP exhaust temperature.

Mr. Halter said the RCA then investigated what caused the high HP exhaust temperature. He said the RCA determined that the CRH piping and exhaust end of the HP steam turbine experienced high temperature estimated to be approximately 1500F. He said the piping is rated for 1150F and the steam turbine components are rated for approximately 1250F. He said this high temperature is the cause of the damage.

Mr. Halter testified the RCA determined the following situations as the cause for the high HP exhaust temperature and he discussed each of these situations: (1) insufficient flow of steam through the HP turbine to remove heat generated by windage; (2) HP steam pressure and temperature supplied to the HP turbine; (3) insufficient notification and response to high HP exhaust temperature condition; and (4) operation of the steam turbine for an extended period of time (five hours and nine minutes) at FSNL condition. Mr. Halter testified that during the startup in November 2021, all four of the situations described above worked together to cause the damaging temperature in the HP exhaust. He said reviewing historical data, in which there was not a failure, each of these situations have occurred before; however, these situations had not occurred all at the same time.

Mr. Halter identified the RCA corrective actions and recommendations and stated Applicant had completed all these actions.

I. <u>Updated Start-Up Operations</u>. Mr. Halter discussed the latent issues with temperature and pressure and the control system changes made by Applicant to safeguard against a recurrence. He compared the start-up operations relevant to HP steam and exhaust temperature and pressure for Incident 1B and the March start-up. He said the steam turbine will not be allowed to start until the startup mode is activated, the HP steam temperature and pressure are within design parameters, and the CRH pressure is within design parameters. He presented data illustrating this point. Mr. Halter said these figures demonstrate the effectiveness of the controls system to control the steam conditions, which ultimately control the HP exhaust temperature. He said this clearly shows that there were deficiencies in the control system. He said the control system protection will be functional even if an operator places any of the equipment into manual mode.

J. Fuel Procurement and Fuel Costs. AES Indiana witness Jackson addressed the impact of the Outage on fuel procurement and fuel costs. Mr. Jackson identified the FAC proceedings affected by the Outage (April 25, 2021 to March 18, 2022) where certain fuel cost recovery was approved on an interim basis or deferred pending outcome of this subdocket.

Mr. Jackson testified that the Outage was not the only factor affecting the FAC during the FAC 133 through FAC 136 period. He said throughout this period, natural gas and coal prices trended dramatically higher as both markets experienced the global impact of the energy markets. He said natural gas exports increased due to demand for liquified natural gas and coal exports because of higher expected burns and tight inventories. He said domestically, coal inventory was tight due to higher forecast burns and challenges in the transportation sector. Mr. Jackson testified that the higher cost of fuel inputs has led to increases in power prices. He testified that Applicant has reasonably determined what part of the actual fuel and purchased power costs incurred during the period are attributable to the Outage and that this analysis includes the effect of the Outage on the FAC 136 reconciliation period.

He discussed the actions taken by Applicant to mitigate the price risk of the Outage by completing financial peak power hedges and natural gas hedges. Mr. Jackson testified that, at the end of May 2021, AES Indiana entered into financial power hedges for peak power during the months of June through August of 2021. He explained that on June 18, 2021, AES Indiana entered into financial peak power hedges for the month of September 2021; on September 29 and 30, 2021, AES Indiana entered into financial peak power hedges for October 2021; and on December 1, 2021, AES Indiana entered into a financial peak power hedge for December 6 through 17, 2021. Mr. Jackson testified that AES Indiana supported the hedge decisions, execution, and financial results in FAC 133, 134 and 135. He added that AES Indiana chose to hedge natural gas instead of power in January and February 2022.

Mr. Jackson discussed the process AES Indiana used to determine the appropriate volume of the power hedges. He testified that the power hedges were reasonable based on the facts and circumstances as they existed at the time the transaction was entered.

Mr. Jackson presented the value of the Eagle Valley CCGT peak power hedge as compared to realized daily pricing and discussed the factors that impacted the value of the peak power hedge. Mr. Jackson stated that using analysis consistent with the process used to inform the financial power hedge decisions for the months of June through October and December 2021, Applicant evaluated purchasing natural gas instead of peak power hedges. He said in prior evaluations, AES Indiana did not have economic energy length and explained the circumstance was different in January and February, in that AES Indiana had economic energy length based on then-current natural gas and power prices. He said this available economic generation was at a lower cost than peak power prices if Applicant had elected to hedge with financial power and added that for this reason, Applicant elected to purchase natural gas instead of peak power to reduce risk for customers. Mr. Jackson described the transaction completed for January and February 2022 and discussed Applicant's evaluation of the benefit of hedging natural gas instead of hedging peak power. Mr. Jackson noted the OUCC did not challenge the hedging decisions in Applicant's FAC filings and said the Commission found the peak power hedges were reasonable.

Mr. Jackson compared actual historical costs to estimated fuel and purchased power costs had Eagle Valley CCGT been operational and explained that the estimated results show the Outage net impact to retail fuel cost after gains from the financial peak power hedges are applied, as well as purchased power over the benchmark attributable to the Outage. He explained the analysis was performed using the wholesale module in OATI (Open Access Technology International, Inc.) and testified that the analysis shows the total estimated Outage impact to fuel cost variances was $41,518,479 during the historical FAC periods net of the financial peak power and physical natural gas hedge gains and losses of $8,179,967.

Mr. Jackson testified that AES Indiana recovers the cost of power purchased in the MISO market in accordance with the Purchase Power Benchmark Order approved in Cause No. 43414. He said the benchmark procedure applies to an unplanned full forced outage defined as a complete outage due to mechanical or electrical equipment failure, which is not the result of imprudence, malfeasance, nonfeasance, or other inappropriate acts. Mr. Jackson testified that purchased power over the benchmark in FAC 133 through FAC 136 totaled $5,351,911 and of that amount, approximately $4,595,198 is estimated to be attributable to the Outage. He said, in other words, using the analysis described previously, purchased power over the benchmark would have been $4,595,198 lower had Eagle Valley been available.

K. Non-FAC Matters. Mr. Jackson also discussed the impact of the Outage on Applicant's capacity accreditation in MISO and on the Off-System Sales ("OSS") Rider. He testified that these latter two topics do not address costs that are subject to recovery via the FAC but were provided because questions on these topics were asked by the Commission during the technical conference conducted on October 21, 2021, in FAC 133. He explained Applicant's purchase of replacement capacity has positively impacted Eagle Valley CCGT's capacity accreditation in the current planning year and will have a similar impact the next three planning years. He quoted an excerpt from the Commission Order in Cause No. 44795 OSS 6 as recognizing this benefit. Finally, Mr. Jackson said the period of May 2021 through March 2022 had a forecasted margin of $15,054,550 and during the same period, a realized actual OSS margin of $4,799,406.

L. Accounting and Ratemaking. AES Indiana witness Coklow presented Applicant's proposed accounting and ratemaking treatment for the unrecovered deferred fuel and purchased power costs related to the Outage that was calculated by Witness Jackson, including the proposed recovery period.

Ms. Coklow testified that AES Indiana has estimated the portion of the fuel cost variances related to Eagle Valley is $41,518,474. She said the Outage impacted the months of April 2021 through March 2022 and the FAC 133 through FAC 136 filings. She presented the variances that were included in the factor in each of the FAC filings during the Outage period and testified that Applicant included only non-Outage variances in the FAC filings for these periods.

She explained the Order in FAC 133 allowed recovery of 50% of the variance in that proceeding, which was less than the calculated estimate of the non-Outage actual variance. She stated that in FAC 134, AES Indiana proposed to defer all variances while Applicant worked on the calculation to determine the portion of costs and variances that was attributable to the Outage. She explained that in FAC 135 this calculation had been completed and Applicant included the estimated cumulative non-Outage actual variances from FAC 133, 134, and 135 in its request of recovery, while leaving the Eagle Valley impact subject to this subdocket. She testified that in FAC 136 filed in June 2022, AES Indiana proposed to follow the FAC 135 methodology and requested the non-Outage portion for recovery. She said the ending deferral would result in a regulatory asset balance of $41,578,475, which is equal to the estimated variance attributable to the Eagle Valley variance shown in Table 1 of her direct testimony and concluded that the amount of this deferral reflects the total dollar amount at issue in this subdocket.

Ms. Coklow testified that to mitigate rate impact, AES Indiana proposes to recover the estimated Outage portion of the unrecovered fuel and purchased power variances, not including any carrying charges, over four FAC filings starting with the next FAC following the Order in this subdocket. Ms. Coklow said a recovery period of four FAC filings corresponds with the similar period for which the costs were incurred. She said AES Indiana proposes to include this adjustment to future FAC filings as an adjustment on FAC Schedule NHC-1, which is the same treatment that AES Indiana used in FAC 133 and FAC 135 when fuel variances were split over multiple filings.

Ms. Coklow testified that the accounting and ratemaking requested in this filing includes no repair or other non-fuel costs.

She testified that AES is proposing to recover the estimated Outage related fuel and purchased power costs in future FAC filings and therefore, FAC 133 through FAC 135 would no longer need to be subject to refund. She stated that if the Commission were to adopt a different proposal, AES Indiana would still propose that any reconciliation would be included in future FAC filings and this would eliminate the need for FACs 133 through FAC 135 to be subject to refund.

Ms. Coklow discussed the estimated FAC factor impact of AES Indiana's proposal. She testified that in relation to Applicant's factor from FAC 135 and after removing variances associated with FAC 133 and 134, AES Indiana estimates its proposal would result in an average increase of $3.14 or 2.50% for a typical residential customer using 1,000 kWh per month.

5. <u>OUCC and Intervenor Testimony</u>.

A. <u>OUCC</u>. Mr. Eckert provided a general overview of the events leading up to and during the Outage events at issue in this proceeding that occurred at Eagle Valley. He said AES Indiana's failure to put in place basic functional operating procedures and technical documentation set the generating facility at a greater risk of "potentially damaging conditions."

Mr. Eckert began by discussing the history of Eagle Valley. He described the outage at Eagle Valley in 2018 that shut the station down for approximately two months. Citing to portions of Sargent & Lundy's 2018 fire-event RCA report, he explained that Applicant's failure to empty the drain tanks led to a fire at Eagle Valley. He explained the recommendation Sargent & Lundy and AES Indiana made, and stated AES Indiana had implemented all of them except for the logic changes. Mr. Eckert stated GE would not approve the changes to the operating logics because the logic in place was standard and was being used in other commissioned applications without issue.

Mr. Eckert addressed the OUCC's analysis of the April 25, 2021 outage (Incident 1A) and the November 10, 2021 outage (Incident 1B) at Eagle Valley. He summarized the events of Incident 1A and 1B at Eagle Valley. He explained the 41E and 52G Breakers identified in Incident 1B's RCA were the same breakers that showed condition indications during the STG1 startup and synchronization process during Incident 1A. He said both 41E and 52G Breakers showed condition indications on plant operators' screens, requiring inspection and troubleshooting prior to Incidents 1A and 1B. He said based on his understanding of the Incident 1B RCA, the hazardous buildup of unmonitored and uncontrolled high-temperature and high-pressure steam was the catalyst for the CRH pipe exploding and subsequently damaging the steam turbine.

Mr. Eckert discussed what the Incident 1A RCA determined and the observations and recommendations RCI made in its RCA. He also discussed what the Incident 1B RCA determined, what situations RCI identified as acting together to create the outage and what RCI recommended in its RCA. He also described what RCI concluded in its RCA for Incident 1B, which also noted that the Toshiba Technical Information Letter ("TTIL") Revision 1 was not implemented.

Regarding the TTIL, Mr. Eckert stated that it had ceased being disseminated to Eagle Valley leadership for review and implementation sometime between the start of operations and the issuance of the February 2021 TTIL. The last TTIL that Eagle Valley leadership received was in August of 2018. He explained that some time before Incident 1B, Toshiba issued a TTIL warning of conditions that could potentially cause a cold reheat pipe to explode, as experienced at Eagle Valley in Incident 1B. If AES Indiana had received the TTIL and followed its directives, Incident 1B potentially would not have occurred. He explained that the RCA reports point out several instances where operators were inadequately trained and described those instances. Mr. Eckert also discussed why AES Indiana hired Kiewit and Stag Control to perform a review of the Eagle Valley CCGT control narratives and DCS logic. He said Kiewit's review found 258 discrepancies, the details of which have been deemed confidential, and he stated AES Indiana has been taking steps to resolve the discrepancies in the control narratives and DCS logic.

Mr. Eckert also discussed the OUCC's position regarding cost responsibility for the Outage that resulted in the plant being offline for approximately 11 months. He explained that the OUCC inquired into the status of settlement discussions for damages related to Incidents 1A and 1B with the EPC (or other parties) and insurance policies that might cover damages that occurred in Incidents 1A and 1B.

Mr. Eckert stated that AES Indiana became responsible for the plant on April 28, 2018, when it began commercial operations. He said the OUCC recommends the Commission find that AES Indiana ratepayers are not responsible for the Outage and that several parties, including ABB, Chicago Bridge and Iron, Toshiba, Emerson Ovation, Nooter Eriksen, and AES Indiana contributed to and/or were partially responsible for the Outage. He said ratepayers, at a minimum, should not be charged for the $41,518,476 variance that AES Indiana had calculated to be the fuel-related expense incurred as a result of the Outage.

B. **Industrial Group.** Mr. Gorman described Eagle Valley's operating history and provided a comparison of Eagle Valley's performance to other modern CCGT plants, noting Incidents 1A and 1B had a material impact on Eagle Valley's availability and reliability. He also noted that customers continued to pay through rates for the plant's capital and fixed operating costs as though it was continually performing in a reliable and efficient manner.

Mr. Gorman discussed the Outage at Eagle Valley and provided an overview of Incident 1A and Incident 1B. He provided a table of the identified root causes for Incident 1A and discussed the contributing factors to Incidents 1A and 1B. Mr. Gorman also explained the significance of the TTIL. He testified that the RCAs indicate Eagle Valley leadership was unaware of TTIL Revision issued by Toshiba in 2021 because AES Indiana had, for unknown reasons, been dropped off the distribution list and took no corrective action to ensure it remained on the distribution list.

Mr. Gorman explained why he believed it was important that the operational history indicates the same problems arose during multiple cold restarts but went uncorrected. He stated, once AES Indiana took control of Eagle Valley, in four of the five cold start-ups, the HP exhaust high temperature alarm was activated but not corrective actions were taken to address the issue. Mr. Gorman testified the RCAs identified a number of operational errors that contributed to Incidents 1A and 1B. He stated Applicant's operating procedures, lack of accurate wiring diagrams, and failure to train operators to follow OEM procedures "make a clear finding" that AES Indiana should be held accountable for the unit's failure to start up operations starting on April 25, 2021 and extending through the completion of that forced outage through March 18, 2022.

Mr. Gorman also analyzed the impact on AES Indiana's FAC cost due to the Outage and provided an estimated impact of the Outage on Applicant's fuel costs. He explained how he estimated the increase to AES Indiana's fuel cost due to the Outage for FAC 133 through FAC 136. He provided Table 3 showing his estimated increase in FAC fuel costs of $70,870,826. Mr. Gorman expressed disagreement with AES Indiana's estimate of the impact of the Outage on those FACs. He stated Applicant significantly understated the additional sales in Off-System Sales margin that can reduce recoverable FAC costs, thereby materially understating the FAC cost damages caused by Outage.

Mr. Gorman recommended the Commission order AES Indiana to provide a refund to ratepayers, with accrued interest, in the subsequent FAC proceedings, in the amount of approximately $70,900,000 to reflect FAC savings had the Outage not occurred. He said the Outage during the FAC 133 through FAC 136 periods was due to the utility's own imprudent and negligent acts, and the resulting replacement FAC costs should not be recovered from customers. He testified that interest should be awarded to ratepayers for not only any delay in that refund, but also because AES Indiana underestimated the impact of Outage, thus imposing costs on customers that should not have been recovered from ratepayers.

C. <u>CAC</u>. Mr. Inskeep highlighted CAC's concerns with AES Indiana's request to recover certain costs associated with the nearly year-long Outage. He explained at a high level the major reasons he believed Eagle Valley was not operated in a safe and reliable manner. He said together, the RCAs show that AES Indiana played a significant role in causing Incidents 1A and 1B.

Mr. Inskeep reviewed AES Indiana's Eagle Valley Incident 1A and discussed what the RCA for Incident 1A found. He said the RCA team found incidents where wire installation did not adhere to best practices or a reliable electrical protection control system, such as insulated ring lugs not used on CT sensor connecting circuits and incorrect rated wire type used for jumper connections between terminals. He also discussed other factors that contributed to the damage caused by Incident 1A. Mr. Inskeep summarized what the RCA recommended and discussed how these recommendations compare with how AES Indiana believes it should operate Eagle Valley.

Next, he reviewed AES Indiana's Eagle Valley Incident 1B and stated AES Indiana admitted in response to a data request that "Incident 1B created a safety risk." He stated that Eagle Valley operators were not sufficiently trained and prepared to address the high HP steam pressure and temperature issue that occurred on November 10, 2021, noting that Eagle Valley operators were alerted to the high temperatures in the HP exhaust but took no action. He also provided additional comments regarding the alarm received by the operators.

Mr. Inskeep stated that, like Incident 1A, there were wiring issues that also contributed to Incident 1B. He provided the results of AES Indiana's review of the Eagle Valley control systems, narratives, and logic for critical systems and equipment after Incident 1B. He said prior to Incident 1B, AES Indiana did not have design specialists and control system experts conduct a detailed review of the control systems, narratives, and logic for critical systems and equipment. He stated instead, AES Indiana relied on its EPC contractor's representations about the design and operation features and did not verify their accuracy.

Mr. Inskeep stated he agreed that AES Indiana likely believed it was purchasing a plant with automated controls, and that the contract provision it highlighted provides support for that general expectation. He disagreed, however, that this absolves AES Indiana of its responsibility to "trust but verify" that the power plant it purchased had those automated controls in place and were operating correctly. He said AES Indiana also has a responsibility to properly train its personnel so they are prepared to recognize and respond to a failure of automated controls. He discussed the relevance of TTILs. He also testified the control room operators deviated from written startup procedure, which instructed GT2 starting load to be at 16 MW.

Mr. Inskeep discussed the costs AES Indiana identified and how AES Indiana's purchased power benchmark factors into the recovery of costs associated with the Outage. He said factors within AES Indiana's control played a key role in Incidents 1A and 1B, including insufficient personnel training, poor practices and operating procedures, unsafe operations and an inadequate safety culture, overreliance on automation, and a disruptive operating environment. He described his concerns with AES Indiana's estimation of the purchased power and fuel costs attributable to the Outage, asserting Applicant's analysis is opaque and incomplete. He recommended the Commission deny AES Indiana's request to recover $41,518,474 in costs from ratepayers and for the Commission to direct AES Indiana to issue customer refunds for any additional amounts the Commission finds reasonable for other impacts associated with the Outage that were not quantified by AES Indiana.

6. <u>AES Indiana's Rebuttal</u>. Mr. Bigalbal responded to certain matters raised by witnesses for the OUCC, Industrial Group and CAC. He provided clarification regarding plant maintenance and said Applicant performs the maintenance and inspections recommended by the OEMs at their scheduled periods. Mr. Bigalbal disagreed with the suggestion that the Eagle Valley commissioning process should be reviewed and discussed the ongoing review process and the settlement terms in Cause No. 45029.

Mr. Bigalbal explained Applicant necessarily purchases equipment designed and sold by third parties. He stated Applicant performed due diligence in selecting the EPC contractor and the EPC contract has commercially reasonable warranties and damage provisions. He also testified that there is a limitation on consequential damages in the EPC contract—but the existence of this type of clause is consistent with industry practice.

Mr. Bigalbal stated that Applicant has made claims under its insurance policy and as mentioned by Mr. Eckert, Applicant is also assessing options to hold contractors accountable. He said insurance proceeds do not cover the whole amount due to the deductible and uncovered scopes of work, such as the wiring verification and comprehensive controls review. He testified a warranty claim is addressed to the warranted work and does not concern replacement power costs, and any award from arbitration would be used to cover the legal fees and costs and the insurance deductible.

He stated that OUCC witness Eckert mentions the CCGT operators came from the old coal plant, but this should not be viewed negatively. He said one should not conclude that there was no operator training or that training was insufficient based on the RCA.

Mr. Bigalbal also disagreed with Mr. Inskeep's contention that AES Indiana did not operate Eagle Valley in a safe and reliable manner, which created unsafe operating conditions and resulted in significant damages to the plant. He said Applicant has a robust safety program in place and consistently works to improve its safety programs, policies, and culture and operated the plant in a manner that is consistent with good industry practices.

Mr. Bigalbal concluded that AES Indiana acted prudently with the information that it had at the time.

Mr. Halter responded to Mr. Gorman's contention that the Eagle Valley CCGT performance compares unfavorably to national gas fired combined cycle plants generally. He said an apples-to-apples comparison of Eagle Valley's operating performance to the North American Electric Reliability General Availability Data System shows the facility is operating well compared to the national average for combined cycle plants. Mr. Halter presented data comparing the Eagle Valley operational performance for 2019 and 2020. He testified the performance metrics indicate plant personnel, plant leadership, and the control systems are working correctly and there are no underlying issues. He also presented other data to support that the Eagle Valley CCGT is performing well even with the 2018 fire included in the analysis.

Mr. Halter also responded to Messrs. Eckert, Gorman, and Inskeep regarding their assessment of Incidents 1A and 1B. He testified that while the control system issues are technically complex, the significance of the latent deficiencies identified in RCAs should not be disregarded. He stated some of the equipment failures identified in the other parties' testimony involved other parts of the plant and have no connection to Incidents 1A or 1B. Also, he rejected the view that the history of the plant dating back to construction warrants a finding of imprudence regarding the Outage.

Responding to the other parties' testimony regarding the contractor failure to report the disconnected jumper wire and the 86G lockouts manual reset, he said Applicant performed prudent steps to hire, provide safety orientation, and oversee the contractor working on the 52G breaker. Regarding the 86G lockouts manual reset, Mr. Halter testified it is inaccurate to identify human roots as the explicit cause of Incident 1A. He said the lack of a written SOP does not justify the disallowance of all the Outage related fuel and purchased power costs. He said a RCA provides recommendations to minimize the potential for a recurrence of the event; therefore, the recommendation to create a SOP does not imply negligence of AES Indiana.

Regarding Incident 1B, Mr. Halter disagreed with Mr. Inskeep's opinion that AES Indiana should have discovered and corrected the errors in the control narratives and logic. He explained why the contention that Applicant failed to ensure the CCGT was operating consistent with OEM criteria before the commercial operation date is inaccurate. Mr. Halter said the operators believed the alarm was normal since that's what occurred during commissioning. He explained that Applicant reached out to Toshiba and Toshiba stated they do not have audible alarms for TOSMAP. Mr. Halter described nuisance alarms and noted that the RCA recommended to review alarm history and clean up nuisance alarms, which has been completed and is still being reviewed and corrected as continuous improvement.

Responding to Mr. Inskeep's assertion that Applicant acted imprudently because known issues were not properly documented and addressed, Mr. Halter stated that there was a deficiency in the control system that caused the cold reheat drain valve not to function correctly during startup while it was in AUTOMATIC. He stated this is a perfect example of how human error only occurred because the control system did not work correctly.

Mr. Halter testified that Applicant took reasonable steps to sign up for TTIL distribution and to verify that its personnel were on the TTIL distribution list. He explained what occurred and testified it is unclear why Toshiba stopped providing TTIL's to Eagle Valley. He stated it is unreasonable to expect AES Indiana to pursue corrective actions to a TTIL that it was unaware of.

With respect to training, Mr. Halter said the RCAs do not state there is a lack of training overall. He testified the after-the-fact comments made during the RCA interview process are helpful on a going forward basis but should not be used to diminish the amount and quality of training that was provided.

Mr. Halter further elaborated on the control room operators' deviation from the written startup procedure, expressing his disagreement with the idea that management overruling their direct reports is an act imprudence. He stated the GT operating at 90MW was one of the contributing causes and added this is a perfect example of a system that is not functioning correctly and led to human error. With respect to the electrical wiring verification, Mr. Halter said that while the troubleshooting was ongoing during the November 2021 startup, if the automated control systems were working correctly, Incident 1B would not have happened even though the startup was delayed due to troubleshooting.

Mr. Halter responded to Mr. Gorman's statement that the Incident 1B RCA identified the steam turbine operation for an extended period of time at FSNL condition as a contributing factor. He provided the confidential information from Toshiba's Operation and Maintenance Manual and explained there is nothing that states how long a steam turbine can operate at FSNL. In response to statements regarding the number of people in the control room, Mr. Halter said this after-the-fact RCA perspective does not invalidate the prudence of Applicant's decision to have additional resources on hand to oversee and assist with startup.

With respect to operator knowledge, Mr. Halter testified the hindsight analysis revealed Eagle Valley experienced three problems with this automation: (1) the control logic did not match the control narrative or the Toshiba operating specifications; (2) there were not any alarms that the bypass system was controlling the pressure too high; and (3) the operators did not have substantial knowledge on what the pressure setpoints should be during the starting process. He testified when you look at these three problems, it is reasonable for the operators to assume the bypass system is working correctly since the control system is automated and has historically worked and it did not have any alarms to indicate it was not working properly.

Mr. Halter concluded that Applicant has directed matters responsibly and there was no intentional misconduct or conscious disregard for sound utility practice. He further stated that Applicant reasonably selected and relied on qualified contractors and purchased equipment and systems from qualified equipment and systems manufacturers. He said while Applicant has addressed the human circumstances to safeguard against a recurrence, the individualized circumstances of human error here do not warrant the other parties' recommended cost disallowance.

Mr. Jackson responded to Messrs. Gorman and Inskeep regarding the fuel cost impact of the Outage. He reiterated that during the FAC 133 through FAC 136 period, natural gas and coal prices trended dramatically higher as both markets experienced the global impact of the energy markets. He said the higher cost of fuel inputs led to increases in power prices. He said that AES Indiana reasonably used the market price of natural gas to calculate Eagle Valley fuel costs if it were operational.

Mr. Jackson clarified that his direct testimony concerns discrete peak power hedges and natural gas hedges, distinct from Applicant's ongoing hedge program. He stated the Commission authorized the hedging gains and losses to be included in the deferred fuel and purchased power costs. He said Applicant's calculation of the fuel and purchased power costs attributable to the Outage is net of the hedging benefit and, therefore, Applicant's calculation is consistent with the Commission's FAC orders. Mr. Jackson said AES Indiana used a robust process to quantify the fuel and purchased power costs attributable to the Outage. He said Applicant's assumption of Eagle Valley's capacity factor assumed a 3.5% Equivalent Forced Outage Rate and showed a high capacity factor during the modeled period, and thus, the calculation properly reflects the scope of the FAC.

Ms. Coklow addressed the requests for the Commission to issue a refund with accrued interest in this case. She stated that the amount requested by Applicant for recovery has not yet been collected from customers and therefore, any disallowance of this amount would not require a customer refund. Ms. Coklow testified that AES Indiana has already used some tools for rate mitigation and detailed the tools used.

Mr. Cooper responded to Mr. Gorman's calculation and contention that the Outage resulted in $70,870,826 in fuel costs during the FAC 133 through FAC 136 periods. He disagreed with Mr. Gorman's claim that Applicant's method results in an "underestimate" of costs attributable to the Outage. He stated such claim rests on the mistaken view that OSS margins are flowed through the FAC; they are not.

Mr. Cooper explained how AES Indiana allocated FAC costs between Eagle Valley Outage-related costs and all other fuel and purchased power costs. He stated the FAC does not true up energy margin, the FAC trues up customer fuel and purchased power related costs. Mr. Cooper explained his disagreement with Mr. Gorman's contentions regarding OSS margins and described Applicant's changes to Mr. Gorman's analysis to reflect the fuel and purchased power cost associated with the Outage. Mr. Cooper said his calculation shows fuel and purchased power costs attributable to the Outage (net of hedges) are $30,920,100, which is less than the AES Indiana estimate of approximately $41,500,00. He also provided a table detailing the Eagle Valley impact by Incident.

Mr. Zarumba responded from a regulatory policy perspective to the testimony of Messrs. Gorman, Inskeep, and Eckert concerning imprudence. He stated that viewing an individual decision through the lens of hindsight may inappropriately cause the application of a perfect performance standard that is tied to a positive outcome. He said human error is an unavoidable cost of any human endeavor. Additionally, he testified, people can have differences of opinion that are within the range of reasonableness. He stated he believed an imprudent act falls outside of the range of reasonable disagreement.

7. <u>Settlement Agreement and Supporting Testimony</u>. The uncontested Settlement Agreement, which was executed by AES Indiana, the OUCC, the Industrial Group, and the CAC and purports to resolve all the issues before the Commission in this Cause is attached hereto and incorporated by reference. The Settlement Agreement was supported by the testimony of AES Indiana witness Rogers, OUCC witness Eckert, and Industrial Group witness Gorman. All witnesses offering settlement testimony discussed the arm's-length nature of the negotiations, the complexity of the negotiations, and the efforts undertaken to reach an uncontested and balanced settlement that fairly resolves all issues in the case.

Mr. Rogers described the Settlement Agreement. He explained, in summary, the Settlement Agreement resolves all issues related to the Outage in this and prospective proceedings (e.g., OSS Rider, Capacity Adjustment, and rate cases). He said under this comprehensive settlement, AES Indiana agrees not to recover $21,000,000 of previously deferred costs and to credit an additional $6,800,000 to customers in future rates.

Mr. Rogers explained how the Settlement Agreement is organized. He stated Section A.1. of the Settlement Agreement sets forth Applicant's agreement not to seek or recover from customers through rates the following:

a. $21000,000 of previously deferred costs.
b. $5,800,000 of carrying charges that does not include any gross-up for income taxes.
c. $3,700,000 of Incident 1A operation and maintenance ("O&M") related to Outage repairs, wiring verification, RCA (net of $300,000 of estimated insurance recovery).

d. $4,000,000 of Incident 1B O&M related to Outage repairs, controls review, RCA (net of $2,100,000 of estimated insurance recovery).
e. Any O&M related to Incident 1A and 1B including, but not limited to, Outage repairs, controls review, wiring verification, and RCA cost not identified in AES Indiana's case in chief filing, which totals $7,700,000 (net of estimated insurance recovery) as set forth in c. and d. above.

Mr. Rogers explained how the forgone carrying charge amount was calculated. He said carrying charges represent the cost of financing funds for the deferred fuel and purchased power costs over the period that those costs were deferred. He said AES Indiana has not requested or recorded recovery of carrying charges on the deferral. He said the carrying charge amount of $5,800,000 was calculated using the same methodology discussed in AES Indiana witness Coklow's rebuttal testimony. Mr. Rogers explained that the $5,800,000 of foregone carrying charges in the Settlement Agreement reflects the agreed decrease in the recoverable fuel and purchased power costs and the longer recovery period of eight FAC periods, as compared to four FAC periods, as proposed in AES Indiana Witness Coklow's rebuttal testimony. He said the foregone recovery of carrying charges and the elongated recovery period mitigate customer rate impact and are responsive to concerns raised by the other parties.

Regarding the Outage O&M, Mr. Rogers said the amounts identified in the Settlement Agreement are net of estimated insurance recoveries totaling $2,400,000. He explained because the final costs may vary from the amounts identified by Applicant, Section A.1.e sets forth the agreement that AES Indiana will not recover any additional O&M costs related to Incidents 1A and 1B above $7,700,000. He said AES Indiana has recorded these costs to expense and will continue to expense any future similar costs in accordance with the Settlement Agreement. Mr. Rogers testified that this section is in the public interest because it provides a significant rate mitigation for customers.

Mr. Rogers explained Section A.2. of the Settlement Agreement provides that AES Indiana will offset future costs in the amount of $6,800,000 and Section A.3. of the Settlement Agreement sets forth the implementation of the cost offset from Section A.2. He explained this offset will be implemented through a credit in the calculation of the FAC factor in the first FAC filed after issuance of a final Commission order approving the Settlement Agreement, which Applicant anticipates will be FAC 139. He testified this approach is administratively efficient and mitigates the near-term rate impact for customers. He explained this rate mitigation is estimated to impact the factors by approximately ($1.80) per MWh in FAC 139, which will be in effect from June 2023 through August 2023 billing periods. He said while the agreement to forego recovery of the Outage O&M costs also mitigates rates for the benefit of customers, his estimate does not reflect the foregone O&M cost recovery because such costs are not included in the FAC.

Regarding Section A.4., which sets forth the amounts AES Indiana is permitted to recover, Mr. Rogers said the Settling Parties agree AES Indiana shall be authorized to recover through the FAC the remaining previously authorized deferred costs in the amount of $20,518,476 to be amortized over eight FAC periods with no carrying charges. He stated this cost recovery will commence with the first FAC filed after issuance of a final Order approving the Settlement Agreement. In addition, AES Indiana will include this cost recovery in future FAC filings as an adjustment on FAC Schedule NHC-1 and these FAC filings will be subject to the normal reconciliation process that is performed for each FAC filing.

Mr. Rogers explained the Settlement Agreement reasonably allows for the recovery through rates of the remaining $20,518,476 of deferred fuel and purchased power costs relating to the Outage and mitigates rate impact to customers by spreading the recovery over eight FAC periods without carrying charges. He said this equates to $2,564,809 per FAC and is estimated to impact the FAC 139 through FAC 146 factors by approximately $0.78 per MWh which will be in effect from June 2023 through May 2025. He further explained the Settlement Agreement results in savings to customers of $0.80 per MWh in FAC 139 through FAC 146 factors, as compared to full recovery of the $41,518,476 of deferred fuel and purchased power costs related to the Outage.

Mr. Rogers explained Section A.5. of the Settlement Agreement recognizes that AES Indiana may have rights, claims, and causes of action against Toshiba, Emerson, CB&I, GE, or other vendors or contractors with respect to the Outage. He said the parties agree that any amounts received from these companies as well as other vendors or contractors net of all reasonable legal and other costs associated with pursuing said causes of action and any other reasonable costs, including any insurance deductibles, that AES Indiana might incur as part of its resolution of claims with respect to the Outage ("Net Recovery") may be retained by AES Indiana subject to certain conditions.

Mr. Rogers explained that any Net Recovery of O&M costs greater than the O&M amounts in Section A.1. of the Settlement Agreement will be credited to retail customers via the FAC and any Net Recovery by AES Indiana for claims for capital costs related to the outages will be used to reduce the amount recorded to Utility Plant in Service ("UPIS"), as required by Generally Accepted Accounting Principles. He further explained any Net Recovery will also be subject to Section A.6.e. and A.7. He said Section A.6.e provides that any Net Recovery of claims for capital costs greater than the capital investment incurred to repair and replace equipment as a result of the Outage ("Outage Capital Investment") identified in Applicant's testimony ($12,357,339) will be shared with customers via the FAC proceeding, subject to a 50/50 split. He said Section A.7. provides that in the event there is any Net Recovery remaining after implementation of Sections A.5.a., A.5.b. and A.6., which exceeds, in the aggregate, $47,857,339 ($21,000,000 + $3,700,000 + $4,000,000 + $6,800,000 + $12,357,339) then the remaining Net Recovery will be provided on an 80/20 basis to the Indiana Utility Rate Payer Trust (80%) and to fund the community action program network of Indiana Community Action Association to facilitate low-income weatherization in AES Indiana's service territory (20%). He explained this provision reasonably addresses the potential that Applicant might recover costs from third parties. He further explained it also provides Applicant an opportunity to recoup costs disallowed from the ratemaking process from third parties together with the costs incurred to pursue such actions and directs that any net excess will go to the benefit of customers either directly through rates or indirectly through the organizations identified in the Settlement Agreement.

Mr. Rogers explained Section A.6. of the Settlement Agreement addresses the Outage Capital Investment. He said as a general matter, a utility is permitted to earn a return of, and on, invested capital through the ratemaking process. He said the Settlement Agreement provides that Applicant shall not seek, nor be permitted to earn, a return on the Outage Capital Investment. He explained, in other words, the parties agree the intent of this section is to allow AES Indiana a return of, but no return on, the Outage Capital Investment in future AES Indiana base rate cases.

Regarding implementation of Section A.6., Mr. Rogers explained that it will be implemented starting with Applicant's first base rate proceeding following approval of the Settlement Agreement. He said for purposes of determining the retail revenue requirement in the rate case, a reduction will be made to AES Indiana's retail jurisdictional UPIS for the Eagle Valley CCGT in the amount of $12,357,339, net of: (1) accumulated depreciation on the Outage Capital Investment; and (2) any reduction made pursuant to Section A.5.b. of the Settlement Agreement. He explained the reduction in retail jurisdictional UPIS computed in accordance with Section A.6.b. will be recorded in a regulatory asset, which will be amortized through retail rates without carrying charges over 25 years. He explained the effect of this treatment is that AES Indiana will be able to recover the Outage Capital Investment costs through future base rates but will not include the amounts in rate base for purposes of calculating a regulated weighted average cost of capital return "on" in future rate cases. Mr. Rogers testified AES Indiana considers this a compromise and reasonable resolution that benefits the public by mitigating rate impact.

Mr. Rogers explained the Settlement Agreement provides that no other capital expense related to the repair and replacement of equipment because of the Outage has been incurred except for those costs identified in AES Indiana witnesses Bigalbal's and Halter's direct testimony; and AES Indiana will not seek recovery of, or on, through retail rates of any amounts more than $12,357,339. He said like the O&M provision he discussed, this provision recognizes that while the final actual costs incurred by Applicant for the Outage Capital Investment may vary from the amounts reflected in Applicant's direct testimony, any such excess will not be reflected in rates.

Mr. Rogers explained Section A.8. states the interim and subject to refund/reconciliation and true-up basis ordered in FAC 133 through FAC 136 shall be removed and the FAC factors approved therein shall be finalized. He said the parties agree that no other FAC filing should be made interim and subject to refund/reconciliation and true-up as a result of the Outage and this Settlement Agreement. He explained that because the Settlement Agreement is intended to resolve and settle all issues related to the Outage and its associated costs and ratemaking, the past and future FAC factors should no longer be interim and subject to refund/reconciliation and true-up basis pending this subdocket.

Mr. Rogers explained Section A.9. describes AES Indiana's commitment to notify the Commission and the parties of the completion of the two remaining RCA recommendations and the resolution of any claims made under Section A.5. He said the Settlement Agreement establishes that these notices shall be made via a compliance filing in this subdocket subject to the protection of confidential information. Mr. Rogers testified that reporting on the outstanding two RCA recommendations that he identified and resolution of claims via compliance filings in this subdocket is administratively efficient and in the public interest.

Mr. Rogers explained Section A.10. provides that the Settlement Agreement is a comprehensive package resolution. He said this Section states the Settlement Agreement and Order in this Cause shall resolve and settle all issues related to the Outage and its associated costs and ratemaking including the FAC, OSS Rider and Capacity Adjustment trackers, and base rate proceedings. He explained the package resolution of all Outage impacts is reasonable and administratively efficient because it allows for the Outage to be considered in this one docket rather than piecemeal over several dockets.

Mr. Rogers explained why he believes Commission approval of the Settlement Agreement is in the public interest. He stated Applicant presented two RCAs as well as the comprehensive controls reports and discussed this hindsight analysis with the Commission and other parties at technical conferences to facilitate knowledge of the incidents. He explained AES Indiana believes it has made changes to the controls to reasonably safeguard against a recurrence and taken appropriate steps to mitigate the duration and costs of the Outage. Mr. Rogers stated the testimony of AES Indiana's witnesses explains that AES Indiana was not aware of the latent deficiencies in the control systems and protective schemes and discusses how AES Indiana views its actions based on information that it had at the time. He said the testimony filed by the other parties reflects differing views as to the issues related to the Outage, including the causes, responsibility, and costs. Mr. Rogers testified settlement is a reasonable means of resolving a controversial proceeding in a manner that is fair and balanced to all concerned. He said the Settlement Agreement is supported by and within the scope of the evidence presented by the parties, reasonably addresses the concerns raised in this proceeding, and provides a balanced, cooperative outcome of the issues related to the Outage.

Mr. Eckert also testified in support of the Settlement Agreement, noting settlement discussions were complicated due to the different parties' positions and the complex issues surrounding the RCAs, equipment problems, the number of contractors, logic problems, and wiring schematics. He described the ratepayer benefits of the Settlement Agreement and stated AES Indiana's fuel costs will be lower than they otherwise could have been. He described the issues that are resolved in Sections A.5, A.6, and A.7 regarding insurance and warranty claims. He explained that AES Indiana potentially has claims against Toshiba, Emerson, CB&I, GE, or other contractors regarding the Outage. He said the Settlement Agreement resolves issues with any rights, claims, and action that AES Indiana has as a result of the Outage. He explained these settlement terms allow AES Indiana the potential to recover disallowed costs and establish how any Net Recovery greater than $47,857,339 will be credited/shared with retail customers through the FAC and base rates, the Indiana Utility Rate Payer Trust, and the Indiana Community Action Association to facilitate low-income weatherization in AES Indiana's service territory. He stated AES Indiana also agreed to forego a return "on" the $12,357,339 of capital investment to repair the plant. Mr. Eckert explained the Settlement Agreement resolved additional issues in Section A.10., which resolves all issues related to the Outage and its associated costs and ratemaking, including in the FAC, OSS Rider and Capacity Adjustment trackers, and base rate proceedings. He said AES Indiana has also committed to notify the Commission and parties of its completion of the two outstanding RCA recommendations.

Mr. Eckert explained why the OUCC believes the Settlement Agreement is supported by the evidence. He stated, through its regularly filed FAC proceedings, AES Indiana sought recovery of $41,518,476 of deferred fuel and purchased power costs related to the Outage. He said the OUCC and CAC proposed that the entire amount be disallowed while the Industrial Group recommended AES Indiana provide a refund to customers in the amount of $70,900,000. Mr. Eckert said the Settlement Agreement saves AES Indiana's customers over $20,000,000 in fuel costs, not including carrying costs, and protects customers by shielding them from additional

Outage costs that AES Indiana could have sought in future rate proceedings. He explained for all these reasons, the Settlement Agreement is in the public interest, and the OUCC recommends it be approved.

Mr. Gorman summarized the Settlement Agreement and stated that it resolves the parties' dispute related to FAC cost reconciliation collections and other issues. He said the other issues addressed by the Settlement Agreement include base rate recovery, fixed O&M expense recovery, and the treatment of the capital investment cost incurred to restore Eagle Valley to a reliable operating condition.

Mr. Gorman described the Settlement Agreement's resolution of FAC costs. He said the reduction in the amount of potentially recoverable deferred fuel costs, by just over half, reflects a compromise between all the parties of the disputed amount of increased fuel expense caused by the unavailability of Eagle Valley during the Outage periods. He said in addition, AES Indiana is foregoing recovery of carrying charges that would amount to $5,800,000. He explained AES Indiana's agreement to forego recovery of the carrying charges represents an additional savings to ratepayers of amounts that will never be collected through the FAC or otherwise.

Mr. Gorman described the ratepayer credits included in the Settlement Agreement. He said this credit resolves other issues raised by the parties, including disputes over the OSS margins and capacity costs related to the Outage. He further stated the credit will be implemented in its entirety in AES Indiana's first FAC filed after the issuance of a final Order approving the Settlement Agreement.

Mr. Gorman said the Settlement Agreement also outlines the parties' agreement on the treatment of O&M expenses and replacement capital improvements needed to restore Eagle Valley to full and reliable operating conditions, including how these amounts are treated in AES Indiana's next and future rate proceedings. Referring to the Settlement Agreement, he said the parties have agreed that $7,700,000 of non-fuel Outage O&M, net of estimated insurance recovery, will be excluded from recovery in base rates, and $12,357,339 of Outage Capital Investment, net of both accumulated depreciation on the Outage Capital Investment and any recovery from third parties of these capital costs, will be removed from UPIS and recorded in a regulatory asset and amortized through retail rates without carrying charges over 25 years. He stated the Settlement Agreement includes provisions addressing the situation if AES Indiana's total Net Recovery of Outage costs from third parties exceeds the total of the disallowed FAC costs, net O&M costs, the customer credit, and Outage-related capital improvements. Specifically, he stated that any net recovery of O&M costs above the $7,700,000 in O&M costs identified in the Settlement Agreement will be credited to retail ratepayers via the FAC. With respect to Outage Capital Investment, the net recovery will be used to reduce the amount recorded to UPIS and net recovery that exceeds $12,357,339 of Outage Capital Investment will be shared by Applicant with its customers on a 50/50 basis. Finally, he stated that should Net Recovery exceed the total of the disallowed FAC costs, net O&M costs, the customer credit, and Outage-related capital improvements, or approximately $47,857,339, that recovery would be distributed to the Indiana Utility Ratepayer Trust and to assist low-income weatherization programs in Applicant's service territory.

Mr. Gorman testified he believes the Settlement Agreement is a reasonable resolution of the additional costs incurred by AES Indiana that are associated with the Outage.

8. <u>Commission Discussion and Findings</u>. Settlements presented to the Commission are not ordinary contracts between private parties. *U.S. Gypsum, Inc. v. Ind. Gas Co.*, 735 N.E.2d 790, 803 (Ind. 2000). When the Commission approves a settlement, that settlement "loses its status as a strictly private contract and takes on a public interest gloss." *Id*. (quoting *Citizens Action Coal. of Ind., Inc. 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 Coal.*, 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. *U.S. Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coal. of Ind., Inc. v. Pub. Serv. Co. 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 Ind. Code ch. 8-1-2, and that such agreement serves the public interest.

This subdocket was initiated in FAC 133 to allow the Commission and the parties additional time to examine the impact of Incident 1A on fuel procurement and fuel costs and was subsequently expanded to include Incident 1B. Through this proceeding, the parties had the opportunity to present additional evidence concerning the Outage. The RCAs that AES Indiana performed and subsequently submitted to the Commission revealed problems we would not expect to see in a standard new CCGT facility. The parties' testimony and exhibits illustrate the gravity, magnitude, and appreciation of the seriousness of the system failures AES Indiana experienced with the Outage at Eagle Valley. Consequently, the Commission has before it substantial evidence from which to judge the reasonableness of the terms of the Settlement Agreement and, after careful consideration, finds the Settlement Agreement is reasonable, just, and properly balances the interests of AES Indiana and its customers.

AES Indiana's initial case-in-chief requested authority to recover $41,518,476 of deferred fuel and purchased power costs related to the Outage. AES Indiana deferred the fuel and purchased power costs based on Commission orders in FAC 133 through FAC 136, which authorized the factors as interim and subject to refund/reconciliation and true-up pending the resolution of this subdocket. The OUCC, CAC, and the Industrial Group took issue with the requested cost recovery associated with the Outage. They argued that the deferred amounts should not be recovered, or that a refund was due to customers. On rebuttal, AES Indiana contested the positions taken by the parties.

To resolve the issues, all parties joined in the Settlement Agreement subject to Commission approval. AES Indiana, the OUCC, and the Industrial Group presented evidence supporting the Settlement Agreement as a reasonable and balanced resolution to the issues described above. The Settlement Agreement resolves all pending issues in this subdocket and addresses potential costs and ratemaking issues regarding OSS Rider and Capacity Adjustment trackers and base rate proceedings related to the Outage.

The Settlement Agreement reflects the significant collaboration and compromise inherent in serious negotiations among a diverse group of interests. The recovery of the deferred Outage costs was in dispute and the record shows the Settlement Agreement reasonably allows for some recovery of the costs within the range of evidence presented by the parties. Under this comprehensive settlement, AES Indiana agrees not to recover $21,000,000 of previously deferred costs and to credit an additional $6,800,000 to customers in future rates to address concerns raised by the other parties. The reduction in the amount of potentially recoverable deferred fuel costs, by just over half, reflects a compromise among the parties of the disputed amount. In addition to reducing AES Indiana's cost recovery, the negotiated resolution of the issues mitigates customer impact by extending the cost recovery period without carrying charges and provides for a significant near-term rate credit. AES Indiana's agreement to forego recovery of approximately $5,800,000 in carrying charges represents a compromise to the litigated positions and clarifies the amount will never be collected through the FAC or otherwise.

As explained by Mr. Eckert and summarized above, the comprehensive Settlement Agreement also protects customers by shielding them from additional Outage costs that AES Indiana could have sought in future rate proceedings. The Settlement Agreement also includes reasonable reporting requirements concerning completion of the remaining two RCA recommendations and updates on the resolution of any third-party claims.

The Settlement Agreement also includes provisions that potentially provide ratepayers with additional benefit. As set out in Section A.5., the Settlement Agreement provides that AES Indiana may have rights, claims, and causes of actions against third parties with respect to the Outage. Any Net Recovery may be retained by AES Indiana subject to the conditions set forth in the Settlement Agreement and Net Recovery above certain amounts will be shared with customers either directly or indirectly. Section A.5.a. states that any Net Recovery of O&M costs above the $7,700,000 in O&M identified in Sections A.1.c. and A.1.d. will be credited to retail ratepayers through the FAC. Section A.5.b. clarifies that any Net Recovery for claims for capital costs related to the Outage will be used to reduce the amount recorded to UPIS. In addition, Section A.6. provides the net Outage Capital Investment will be recorded in a regulatory asset and amortized through rates over 25 years without carrying charges. Section A.6.e. provides that any Net Recovery of claims for capital costs above the $12,357,339 will be shared 50/50 between AES Indiana and its retail customers.

Finally, Sections A.5.c. and A.7. clarify that any Net Recovery, in the aggregate, over $47,857,339 (which equals the total of unrecovered deferred fuel cost, the agreed to O&M expense, the ratepayer credit, and the capital costs associated with the Outage) will be distributed to the Indiana Utility Ratepayer Trust and the community action program network of Indiana Community Action Association to facilitate low-income weatherization in AES Indiana's service territory. These provisions recognize the potential for recovery of costs from third parties and reasonably share any remaining Net Recovery with ratepayers as specified above, after which any remaining Net Recovery will be used indirectly to support ratepayers. Thus, we find these provisions are not inconsistent with the bargain of the parties and resulting comprehensive agreement.

Based upon our review of the record and consideration of the Settlement Agreement and supporting testimony and exhibits, the Commission finds the Settlement Agreement is within the range of potential overall outcomes and represents a just and reasonable resolution of the issues. Therefore, having determined that approval of the Settlement Agreement is in the public interest and reasonably resolves all issues in this subdocket as well as other future proceedings, we approve the Settlement Agreement in its entirety.

9. Effect of Settlement Agreement. Regarding future citation of this Order, the Commission finds our approval herein should be construed in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 WL 34880849 at *7-8 (IURC March 19, 1997).

10. Interim Rate Disposition. The interim rate and subject to refund/reconciliation and true-up conditions imposed on the FAC factors approved in FAC 133 through FAC 136 shall be removed and terminated.

11. Confidential Information. On May 24, 2022, June 1, 2022, and September 7, 2022, AES Indiana filed Motions for Protection and Nondisclosure of Confidential and Proprietary Information in this Cause, which were supported by affidavits showing that certain information to be submitted to the Commission was trade secret information as defined in Ind. Code § 24-2-3-2 and should be treated as confidential in accordance with Ind. Code §§ 5-14-3-4 and 8-1-2-29. In Docket Entries dated May 27, 2022, June 3, 2022, and September 19, 2022, the Presiding Officers found the information should be held confidential on a preliminary basis. After review of the information and consideration of the affidavits, we find the information is trade secret information as defined in Ind. Code § 24-2-3-2, is exempt from public access and disclosure pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29, and shall be held as 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, a copy of which is attached to this Order, is approved and this subdocket is closed.

2. AES Indiana shall implement the agreed rate credit in the FAC in accordance with the Settlement Agreement.

3. AES Indiana is authorized to recover $20,518,476 of the previously deferred fuel and purchased power costs through the FAC in accordance with the Settlement Agreement.

4. AES Indiana is granted accounting authority to implement the Settlement Agreement, including authority to record the reduction in retail jurisdictional UPIS computed in accordance with Section A, Paragraph 6.b. of the Settlement Agreement in a regulatory asset. The regulatory assets shall be amortized as provided in the Settlement Agreement.

5. The interim and subject to refund/reconciliation and true-up conditions imposed in Applicant's FAC proceedings pending this subdocket are terminated and removed.

6. The information filed in this Cause pursuant to AES Indiana's motions for protective order are deemed confidential pursuant to Ind. Code §§ 5-14-3-4 and 8-1-2-29, 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.

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

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

APPROVED: JAN 18 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: 2023.01.18 10:12:48
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Dana Kosco
Secretary of the Commission

IURC JOINT EXHIBIT No. 1 11-21-22 AT DATE REPORTER

OFFICIAL EXHIBITS

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

SUBDOCKET FOR REVIEW OF INDIANAPOLIS POWER & LIGHT COMPANY D/B/A AES INDIANA'S 2021 EXTENDED FORCED OUTAGE AT EAGLE VALLEY AND ITS RELATED IMPACT ON FUEL PROCUREMENT AND FUEL COSTS.	)	**CAUSE NO. 38703 FAC 133 S1**

STIPULATION AND SETTLEMENT AGREEMENT

Indianapolis Power & Light Company d/b/a AES Indiana ("AES Indiana", "IPL" or "Company"), the Indiana Office of Utility Consumer Counselor ("OUCC"), Citizens Action Coalition of Indiana, Inc. ("CAC"), AESI Industrial Group ("IG") (collectively the "Settling Parties" and individually "Settling Party"), solely for purposes of compromise and settlement and having been duly advised by their respective staff, experts and counsel, stipulate and agree that the relief sought by AES Indiana shall be approved as modified below and the terms and conditions set forth below represent a fair, just and reasonable resolution of the matters pending in this Cause, subject to their incorporation by the Indiana Utility Regulatory Commission ("Commission") into a final, non-appealable order ("Final Order")[1] without modification or further condition that may be unacceptable to any Settling Party. If the Commission does not approve this Stipulation and Settlement Agreement ("Settlement Agreement"), in its entirety, the entire Settlement Agreement shall be null and void and deemed withdrawn, unless otherwise agreed to in writing by the Settling Parties.

A. Terms and Conditions.

Solely for the purpose of compromise, the Parties agree to Commission approval of a settlement regarding the cost recovery associated with the Eagle Valley CCGT forced outage that occurred April 25, 2021 to March 18, 2022 ("Outage").

1. AES Indiana agrees not to seek nor recover from ratepayers through rates the following:
    a. $21.0 million of previously deferred costs.
    b. $5.8 million of carrying charges.

[1] "Final Order" as used herein means an order issued by the Commission as to which no person has filed a Notice of Appeal within the thirty-day period after the date of the Commission order.

c. $3.7 million of Incident 1A O&M related to outage repairs, wiring verification, RCA (net of $0.3 million of estimated insurance recovery).
d. $4.0 million of Incident 1B O&M related to outage repairs, controls review, RCA (net of $2.1 million of estimated insurance recovery).
e. Any O&M related to Incident 1A and 1B including, but not limited to, outage repairs, controls review, wiring verification, and RCA cost not identified in AES Indiana's case in chief filing, which totals $7.7 million (net of estimated insurance recovery) as set forth in subparagraphs c and d above.

2. For purposes of settlement to resolve issues raised by the Consumer Parties, AES Indiana agrees to offset future costs in the amount of $6.8 million.

3. AES Indiana shall implement the cost offset in Paragraph 2 via a credit in the calculation of the FAC factor in the first FAC filed after issuance of a final Commission order approving this Settlement Agreement (anticipated to be FAC 139).

4. AES Indiana shall be authorized to recover through the FAC the remaining previously authorized deferred costs in the amount of $20,518,476 to be amortized over eight FAC periods (two years) instead of four FAC periods as proposed by AES Indiana, with no carrying charges.

   a. Such cost recovery shall commence with the first FAC filed after issuance of a final Order approving this Settlement Agreement (anticipated to be FAC139).
   b. AES Indiana will include this cost recovery in the future FAC filings as an adjustment on FAC Schedule NHC-1.
   c. These FAC filings will be subject to the normal reconciliation process that is performed for each FAC filing.

5. AES Indiana may have rights, claims and causes of action against, Toshiba, Emerson, CB&I, GE or other vendors or contractors with respect to the Eagle Valley CCGT Outage. Any amounts received from these companies as well as other vendors or contractors net of all reasonable legal and other costs associated with pursuing said causes of action and any other reasonable costs, including any insurance deductibles, that AES Indiana might incur as part of its resolution of claims with respect to the Outage ("Net Recovery") may be retained by AES Indiana subject to the following:

   a. Any Net Recovery of O&M costs above the O&M amounts set forth in Paragraph 1 shall be credited to retail ratepayers via the FAC.
   b. Any Net Recovery by AES Indiana for claims for capital costs related to the Eagle Valley CCGT Outage will be used to reduce the amount recorded to Utility Plant In Service (as required by GAAP).
   c. Paragraphs 6e and 7 below.

6. Starting with the Company's first base rate proceeding following approval of this Settlement Agreement:
   a. The Company shall not seek, nor be permitted to earn, a return "on" any capital investment incurred to repair and replace equipment as a result of the Outage ("Outage Capital Investment").
   b. To implement the terms of this agreement for purposes of determining the retail revenue requirement in the rate case, a reduction shall be made to AES Indiana's retail jurisdictional UPIS for the Eagle Valley CCGT in the amount of $12,357,339 as identified in AES Indiana's direct testimony in this Cause, net of: (i) accumulated depreciation on the Outage Capital Investment; and (ii) any reduction made pursuant to Paragraph 5b above.
   c. The reduction in retail jurisdictional UPIS computed in accordance with Paragraph 6b above will be recorded in a regulatory asset.
   d. The regulatory asset will be amortized through retail rates without carrying charges over twenty-five years.
   e. Any Net Recovery of claims for capital costs above the $12,357,339 will be shared, 50/50 between AES Indiana and its retail customers.
   f. AES Indiana agrees that no other capital expense related to the repair and replacement of equipment as a result of the Outage has been incurred except for those costs identified in witnesses Bigalbal's and Halter's direct testimony; and AES Indiana will not seek recovery of, or on, through retail rates of any amounts in excess of $12,357,339.

7. Any Net Recovery remaining after implementation of Paragraphs 5a, 5b and 6 above, if any, which exceeds, in the aggregate, $47,857,339 ($21,000,000 + $3,700,000 + $4,000,000 + $6,800,000 + $12,357,339) will be provided on an 80/20 basis to the Indiana Utility Rate Payer Trust (80%) and to fund the community action program network of Indiana Community Action Association to facilitate low-income weatherization in AES Indiana's service territory (20%).

8. The interim and subject to refund/reconciliation and true-up basis ordered in Cause No. 38703-FAC133 through FAC 136 shall be removed and the FAC factors approved therein shall be finalized. The parties agree that no other FAC filing should be made interim and subject to refund/reconciliation and true-up as a result of the Outage and this Settlement Agreement.

9. AES Indiana shall notify the Commission and the parties of the completion of the two remaining RCA recommendations (identified in Witness Bigalbal's direct testimony, pg. 17 (lines 7-16). AES Indiana shall also notify the Commission and the Parties of the resolution of any claims made under Paragraph 5 above. These notices shall be made via a compliance filing in this subdocket subject to the protection of confidential information.

10. The Settlement Agreement and Order in this Cause shall resolve and settle all issues related to the Outage and its associated costs and ratemaking including the FAC, Off-System Sales margins and Capacity trackers and base rate proceedings.

B. <u>Presentation of the Settlement Agreement to the Commission</u>.

1. The Settling Parties shall support this Settlement Agreement before the Commission and request that the Commission expeditiously accept and approve the Settlement Agreement.

2. The Settling Parties may file testimony specifically supporting the Settlement Agreement. The Settling Parties agree to provide each other with an opportunity to review drafts of testimony supporting the Settlement Agreement and to consider the input of the other Settling Parties. Such evidence, together with the evidence previously prefiled in this Cause, will be offered into evidence without objection and the Settling Parties hereby waive cross-examination of each other's witnesses. The Settling Parties propose to submit this Settlement Agreement and evidence conditionally, and that, if the Commission fails to approve this Settlement Agreement in its entirety without any change or with condition(s) unacceptable to any Settling Party, the Settlement and supporting evidence shall be withdrawn and subject to Paragraph 3 below, the Commission will continue to hear the matters pending in this Cause with the proceedings resuming at the point they were suspended by the filing of this Settlement Agreement.

3. Discovery shall cease immediately pending Commission approval of the Settlement Agreement and it shall not be necessary for the Company to respond to any discovery requests outstanding as of October 20, 2022 and while the Settlement is pending approval before the Commission. In the event that the Commission rejects the Settlement Agreement, the Parties agree to meet and confer as soon as possible after the issuance of an order rejecting the Settlement Agreement in an effort to reach a new agreement. Should the Parties be unable to reach a new agreement, and this matter proceeds to a contested evidentiary hearing, discovery shall resume and responses to any outstanding discovery request shall be due no later than ten days after the Commission sets the date for the final hearing.

4. A Commission Order approving this Settlement Agreement shall be effective immediately, and the agreements contained herein shall be unconditional, effective and binding on all Settling Parties as an Order of the Commission.

5. The Parties shall jointly agree on the form, wording and timing of public/media announcement (if any) of this Settlement Agreement and the terms thereof. No Party will release any information to the public or media prior to the aforementioned announcement. The Parties may respond individually without prior approval of the other Parties to questions from the public or media, provided that such responses are consistent with such announcement and do not disparage any of the Parties. Nothing in this Settlement Agreement shall limit or restrict the Commission's ability to publicly comment regarding this Settlement Agreement or any Order affecting this Settlement Agreement.

C. Effect and Use of Settlement Agreement.

1. It is understood that this Settlement Agreement is reflective of a negotiated settlement and neither the making of this Settlement Agreement nor any of its provisions shall constitute an admission by any Settling Party in this or any other litigation or proceeding except to the extent necessary to implement and enforce its terms. It is also understood that each and every term of this Settlement Agreement is in consideration and support of each and every other term.

2. Neither the making of this Settlement Agreement (nor the execution of any of the other documents or pleadings required to effectuate the provisions of this Settlement Agreement), nor the provisions thereof, nor the entry by the Commission of a Final Order approving this Settlement Agreement, shall establish any principles or legal precedent applicable to Commission proceedings other than those resolved herein.

3. This Settlement Agreement shall not constitute and shall not be used as precedent by any person or entity in any other proceeding or for any other purpose, except to the extent necessary to implement or enforce this Settlement Agreement.

4. This Settlement Agreement is solely the result of compromise in the settlement process and except as provided herein, is without prejudice to and shall not constitute a waiver of any position that any Settling Party may take with respect to any or all of the items resolved here and in any future regulatory or other proceedings.

5. The evidence in support of this Settlement Agreement constitutes substantial evidence sufficient to support this Settlement Agreement and provides an adequate evidentiary basis upon which the Commission can make any findings of fact and conclusions of law necessary

for the approval of this Settlement Agreement, as filed. The Settling Parties shall prepare and file an agreed proposed order with the Commission as soon as reasonably possible after the filing of this Settlement Agreement and the final evidentiary hearing.

6. The communications and discussions during the negotiations and conferences and any materials produced and exchanged concerning this Settlement Agreement all relate to offers of settlement and shall be 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.

7. The undersigned Settling Parties have represented and agreed that they are fully authorized to execute the Settlement Agreement on behalf of their respective clients, and their successor and assigns, which will be bound thereby.

8. The Settling Parties shall not appeal or seek rehearing, reconsideration or a stay of the Commission Order approving this Settlement Agreement in its entirety and without change or condition(s) unacceptable to any Settling Party (or related orders to the extent such orders are specifically implementing the provisions of this Settlement Agreement).

9. The provisions of this Settlement Agreement shall be enforceable by any Settling Party first before the Commission and thereafter in any state court of competent jurisdiction as necessary.

10. This Settlement Agreement may be executed in two 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 as of the 25th day of October, 2022.

AES Indiana

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