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

ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH ("CEI SOUTH") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE-IN OF RATES, (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, AND NEW AND REVISED RIDERS, INCLUDING BUT NOT LIMITED TO A NEW TAX ADJUSTMENT RIDER AND A NEW GREEN POWER RIDER (3) APPROVAL OF A CRITICAL PEAK PRICING ("CPP") PILOT PROGRAM, (4) APPROVAL OF REVISED DEPRECIATION RATES APPLICABLE TO ELECTRIC AND COMMON PLANT IN SERVICE, (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING AUTHORITY TO CAPITALIZE AS RATE BASE ALL CLOUD COMPUTING COSTS AND DEFER TO A REGULATORY ASSET AMOUNTS NOT ALREADY INCLUDED IN BASE RATES THAT ARE INCURRED FOR THIRD-PARTY CLOUD COMPUTING ARRANGEMENTS, AND (6) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN GRANTING CEI SOUTH A WAIVER FROM 170 IAC 4-1-16(f) TO ALLOW FOR REMOTE DISCONNECTION FOR NON-PAYMENT.

CAUSE NO. 45990

APPROVED: FEB 03 2025

ORDER OF THE COMMISSION

Presiding Officers:
David E. Veleta, Commissioner
Jennifer L. Schuster, Senior Administrative Law Judge

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On December 5, 2023, Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South" or "Petitioner") filed its Verified Petition for General Rate Increase and Associated Relief under Ind. Code § 8-1-2-42.7 and an Alternative Regulatory Plan under Ind. Code Ch. 8-1-2.5 and Notice of Provision of Information in Accordance with the Minimum Standard Filing Requirements ("Petition") with the Indiana Utility Regulatory Commission ("Commission"), seeking (1) authority to modify its rates and charges for electric utility service through a phase-in of rates, (2) approval of new schedules of rates and charges, and new and revised riders including but not limited to a new tax adjustment rider ("TAR") and a new green energy rider, (3) approval of a Critical Peak Pricing ("CPP") pilot program, (4) approval of revised depreciation rates applicable to electric and common plant in service, (5) approval of necessary and appropriate accounting relief, including authority to capitalize as rate base all cloud computing costs and defer to a regulatory asset amounts not already included in base rates that are incurred for third-party cloud computing arrangements ("CCAs"), (6) approval of an Alternative Regulatory Plan ("ARP") granting CEI South a waiver from 170 IAC § 4-1-16(f) to allow for remote disconnection for non-payment, and (7) other requests as described in its Petition initiating this Cause.

That same day CEI South also filed the direct testimony and attachments and financial exhibit (in Excel and PDF format) constituting its case-in-chief in this Cause, including direct testimony from the following witnesses:[1]

- Richard Leger, Interim Vice President, Natural Gas Business,[2] Southern Indiana Gas and Electric Company
- Chrissy M. Behme, Manager, Regulatory Reporting, CenterPoint Energy Service Company, LLC ("Service Company")
- Stephanie E. Gray, Manager, Indiana Electric Finance Planning and Analysis, Service Company
- Stephen R. Rawlinson, Director of Electric Engineering, Southern Indiana Gas and Electric Company
- Amy L. Folz, Director, Indiana High Voltage Operations, Southern Indiana Gas and Electric Company
- Gregg M. Maurer, Director, Indiana Electric Distribution Operations, Southern Indiana Gas and Electric Company
- F. Shane Bradford, Vice President of Power Generation Operations, Southern Indiana Gas and Electric Company
- Ronald W. Bahr, Vice President, Information Technology, Service Company
- Christopher G. Wood, Director of Process and Data Governance, Service Company

[1] On March 1, 2024, corrections were submitted to the direct testimony of witnesses Behme, Gray, Maurer, Bradford, Bahr, Williford, Kopp, and Bulkley. On March 7, 2024, corrections were submitted to the direct testimony of witnesses Rice and Forshey. On August 28, 2024, additional corrections were submitted to witness Bulkley's direct testimony. At the evidentiary hearing witnesses Leger and Rice made minor corrections to their direct testimony.

[2] On January 12, 2024, Petitioner late-filed witness Leger's Attachments RCL-3 and RCL-4, consisting of Proofs of Legal Notice Publication and Customer Notice, and certified that the legal notice required to be published pursuant to Ind. Code § 8-1-2-61(a) and Ind. Code § 8-1-2.5-6(d) had been published and posted to Petitioner's website.

- Deneisia R. Williford, Vice President of Total Rewards & Technology,[3] Service Company
- Jeffrey T. Kopp, Senior Managing Director, Energy & Utilities Consulting, 1898 & Co.
- John J. Spanos, President, Gannet Fleming Valuation and Rate Consultants, LLC[4]
- Ann E. Bulkley, Principal, The Brattle Group
- Brett A. Jerasa, Assistant Treasurer, Service Company
- Jennifer K. Story, Vice President of Tax, Service Company
- Michael E. Russo, Senior Forecast Consultant, Itron
- Justin L. Forshey, Director, Energy Solutions and Business Development – Midwest, Service Company
- John D. Taylor, Managing Partner, Atrium Economics
- Matthew A. Rice, Director, Indiana Electric Regulatory and Rates, Service Company

On December 5, 2023, Petitioner also filed a First Motion for Protection and Nondisclosure of Confidential and Proprietary Information, which motion was granted on December 20, 2023. Petitioner filed a Second Motion for Protection and Nondisclosure of Confidential and Proprietary Information on March 28, 2024, which was granted on April 10, 2024. Petitioner filed a Third Motion for Protection and Nondisclosure of Confidential and Proprietary Information on April 4, 2024 and a Fourth Motion for Protection and Nondisclosure of Confidential and Proprietary Information on April 9, 2024, both of which were granted on April 12, 2024.

Also on December 5, 2023, Petitioner filed its Submission of Minimum Standard Filing Requirements.

Petitions to Intervene were filed by Citizens Action Coalition of Indiana, Inc. ("CAC") and CenterPoint Energy Indiana South Industrial Group ("CEIS Industrial Group" or "Industrial Group" or "IG"), SABIC Innovative Plastics Mt. Vernon, LLC ("SABIC"), and the Common Council of the City of Evansville, Indiana ("Evansville Council"). The Commission issued docket entries granting each of said petitions to intervene; thus, all of the entities requesting intervention were made parties to this Cause.

On December 28, 2023, the Commission issued a docket entry establishing a procedural schedule and the test year for determining CEI South's projected operating revenues, expenses, and operating income, which was amended on January 17, 2024, following an unopposed Motion to Amend Procedural Schedule Docket Entry filed by the Indiana Office of Utility Consumer Counselor ("OUCC"). The January 17, 2024 docket entry established the forward-looking test year as the 12-month period ending December 31, 2025 and established the rate base cutoff date at the

[3] Ms. Williford's title changed on February 12, 2024 after the filing of her direct testimony. Pet. Ex. 10-R at 1.

[4] On January 5, 2024, Petitioner submitted a corrected version of the pre-filed testimony of witness Spanos and filed a motion to substitute the initial public version of witness Spanos' pre-filed testimony, which inadvertently included confidential information, with the now corrected version.

end of the test year, with associated rate base cutoff dates for each phase of CEI South's proposed three-phase increase.

Pursuant to Ind. Code § 8-1-2-61(b), two public field hearings were held in Evansville on February 29, 2024, at which time members of the public presented testimony.

On March 12, 2024, the OUCC, CEIS Industrial Group, CAC, Evansville Council, and SABIC prefiled their respective cases-in-chief and/or direct testimony.

The OUCC's prefiled case-in-chief included customer comments[5] and testimony and attachments from the following witnesses:[6]

- Michael D. Eckert, Director, Indiana Office of Utility Consumer Counselor's Electric Division
- Brian R. Latham, Utility Analyst, Indiana Office of Utility Consumer Counselor's Electric Division
- Kaleb G. Lantrip, Utility Analyst, Indiana Office of Utility Consumer Counselor's Electric Division
- Brittany L. Baker, Utility Analyst, Indiana Office of Utility Consumer Counselor's Electric Division
- Jason T. Compton, Utility Analyst, Indiana Office of Utility Consumer Counselor's Water/Wastewater Division
- Margaret A. Stull, Chief Technical Advisor, Indiana Office of Utility Consumer Counselor's Water/Wastewater Division
- Cynthia M. Armstrong, Assistant Director, Indiana Office of Utility Consumer Counselor's Electric Division
- Brian Wright, Utility Analyst II, Indiana Office of Utility Consumer Counselor's Electric Division
- Greg L. Krieger, Utility Analyst, Indiana Office of Utility Consumer Counselor's Electric Division
- Shawn Dellinger, Senior Utility Analyst, Indiana Office of Utility Consumer Counselor's Water/Wastewater Division
- David J. Garrett, Managing Member, Resolve Utility Consulting, PLLC
- Dr. David D. Dismukes, Consulting Economist, Acadian Consulting Group
- April M. Paronish, Assistant Director, Indiana Office of Utility Consumer Counselor's Electric Division

The OUCC filed a Motion for Protection and Nondisclosure of Confidential and Proprietary Information on March 12, 2024, which was granted on April 10, 2024.

[5] Customer comments were supplemented by motion filed April 24, 2024, which was granted by docket entry dated April 25, 2024.

[6] On March 19, 2024, a correction to redact additional information in witness Wright's testimony was filed. On March 28, 2024, corrections were submitted to witnesses Eckert, Lantrip, and Paronish. On April 10, 2024, corrections were submitted to the testimony of witnesses Paronish and Krieger. On April 25, 2024, corrections were submitted to the testimony of witnesses Eckert, Latham, Lantrip, Compton, Stull, and Krieger.

CEIS Industrial Group's prefiled case-in-chief included testimony and attachments from the following witnesses:

- Michael P. Gorman, Managing Principal, Brubaker & Associates, Inc.
- Jessica York, Principal, Brubaker & Associates, Inc.

CEIS Industrial Group filed a First and Second Motion for Protection and Nondisclosure of Confidential and Proprietary Information on March 12, 2024, and March 14, 2024, respectively, which were both granted on April 10, 2024.

The CAC's prefiled case-in-chief included testimony and attachments from the following witnesses[7]:

- Kerwin Olson, Executive Director, CAC
- Benjamin Inskeep, Program Director, CAC
- Justin Barnes, President, EQ Research, LLC

The Evansville Council prefiled testimony from Zachary Heronemus, President, Evansville Common Council.

SABIC prefiled the testimony and attachments of Kyra J. Coyle, Senior Manager, NewGen Strategies & Solutions, LLC.[8]

On April 9, 2024, CEIS Industrial Group filed the cross-answering testimony of Jessica A. York,[9] and the CAC filed the cross-answering testimony of Benjamin Inskeep and Justin Barnes.

Also on April 9, 2024, CEI South filed rebuttal testimony, exhibits, and workpapers of witnesses Leger, Behme, Rawlinson, Folz, Bradford, Bahr, Williford, Spanos, Bulkley, Jerasa, Story, Russo, Forshey, Taylor, Rice, and Jason A. Cunningham, Manager, Property Accounting, Service Company.[10] Revised Excel and PDF versions of the revenue requirement model were also filed.

On April 22, 2024, the OUCC filed a Motion to Strike certain portions of rebuttal testimony and attachments filed by CEI South. Pursuant to the Commission's briefing schedule set by docket entry on April 23, 2024, CEI South responded on April 25, 2024, and the OUCC replied on April 29, 2024. No objections were raised to the admission of the testimony that was subject to the Motion to Strike at the evidentiary hearing. Thus, the Motion to Strike is denied as moot.

On April 26, 2024, CEI South filed a Motion for a Two-Day Continuance to reschedule the evidentiary hearing set for April 30, 2024, to continue settlement discussions with the parties. The Commission, by docket entry, granted CEI South's Motion for a Two-Day Continuance on

[7] On March 22, 2024, CAC filed an opposed revised redaction to witness Barnes's testimony.

[8] A correction to redact additional information was filed on April 18, 2024.

[9] A revised version of witness York's cross-answering testimony was filed on April 24, 2024.

[10] Corrections to Mr. Rice's rebuttal testimony were filed on August 20, 2024. Mr. Rice noted further minor corrections to his rebuttal testimony at the evidentiary hearing on September 11, 2024.

April 26, 2024, and rescheduled the evidentiary hearing for May 2, 2024. On April 30, 2024, CEI South filed a Motion for an Additional One Day Continuance to further continue settlement discussions which the Commission granted by docket entry on May 1, 2024, and rescheduled the evidentiary hearing for May 3, 2024. A Third and a Fourth Motion for a Continuance to continue settlement discussions were filed by CEI South on May 2, 2024, and May 8, 2024, respectively. The Commission, by docket entry, granted the third continuance on May 2, 2024, and the fourth continuance on May 9, 2024 and rescheduled the evidentiary hearing date for May 14, 2024.

On April 29, 2024, the Commission issued a docket entry requesting information from CEI South, to which CEI South filed a public and confidential response on May 2, 2024 (Pet. Ex. 23 and 23-C).

On May 10, 2024, CEI South provided an update on settlement discussions and filed an uncontested motion to vacate the current procedural schedule and stated it would file a proposed settlement procedural schedule for the submission date of the non-unanimous settlement and further proceedings by May 14, 2024. On May 13, 2024, the Commission by docket entry granted the motion and vacated all further proceeding dates and deadlines in the procedural schedule and stipulated that should the parties not reach an agreement on a settlement procedural schedule by May 14, then a new evidentiary hearing date will be set for May 29, 2024.

On May 14, 2024, CEI South filed a settlement proposed procedural schedule agreed upon by CEI South, CEIS Industrial Group, and SABIC (collectively, the “Settling Parties”) which was granted by docket entry on May 15, 2024. On May 17, 2024, the Settling Parties filed an updated settlement procedural schedule to include additional proceedings for the non-settling parties to contest the Settling Parties’ procedural schedule as indicated in the Commission’s May 15, 2024 docket entry. The updated settlement procedural schedule was granted by the Commission by docket entry on May 22, 2024, and the hearing set for May 29, 2024, was rescheduled as a settlement hearing set for September 3, 2024.

On May 20, 2024, CEIS Industrial Group filed settlement testimony for witnesses York and Gorman. That same day, CEI South filed settlement testimony, exhibits, and workpapers for witnesses Behme, Jerasa, Taylor, and Rice. On May 21, 2024, CEI South submitted the Settling Parties’ Joint Exhibit No. 1, the Stipulation and Settlement Agreement among the Settling Parties (“Settlement Agreement” or “Settlement”) that was inadvertently omitted from its initial filing on May 20, 2024. On August 23, 2024, and August 28, 2023 corrections were submitted to witness Rice’s settlement direct testimony and attachments. Mr. Rice noted further minor corrections to his settlement testimony at the evidentiary hearing on September 11, 2024.

On July 19, 2024, the OUCC filed settlement testimony, exhibits, and workpapers in opposition of the Settlement for witnesses Eckert (Pub. Ex. 1-S), Compton (Pub. Ex. 5-S), Stull (Pub. Ex. 6-S), Wright (Pub. Ex. 8-S), Krieger (Pub. Ex. 9-S), Dellinger (Pub. Ex. 10-S), Dismukes (Pub. Ex. 12-S), and Paronish (Pub. Ex. 13-S).

On July 19, 2024, the CAC filed settlement testimony, exhibits, and workpapers in opposition of the Settlement for witnesses Inskeep and Barnes. On July 23, 2024, CAC submitted corrections to witness Inskeep’s testimony.

On August 2, 2024, CEI South, the CEIS Industrial Group and SABIC filed settlement rebuttal testimony of witnesses Jerasa, Taylor, Rice, Gorman, York, and Coyle.

On August 26, 2024, the Commission issued a docket entry requesting information from CEI South, to which CEI South responded on August 28, 2024 (Pet. Ex. 24).

The Commission held an evidentiary hearing in this Cause starting on September 10, 2024 at 1:30 p.m. and continuing on September 11, 2024 in Room 222 of the PNC Center, 101 West Washington Street, Indianapolis, Indiana. CEI South, the OUCC, and Intervenors were present and participated through counsel. The testimony and exhibits of the parties were admitted into the record without objection.

Having considered the evidence of record and based on the applicable law, the Commission now finds:

1. **<u>Notice and Jurisdiction</u>.** Due, legal, and timely notice of the Petition filed in this Cause was given and published by Petitioner as required by law. Proper and timely notice was given by Petitioner to its customers summarizing the nature and extent of the proposed changes in its rates and charges for electric service. Pet. Ex. 1, Attachments RCL-3 and RCL-4. Due, legal, and timely notices of the public hearings in this Cause were given and published as required by law. Petitioner is a "public utility" as defined in Ind. Code ch. 8-1-2 and is subject to the jurisdiction of the Commission in the manner and to the extent provided by Indiana law. CEI South is also a "utility" within the meaning of Ind. Code § 8-1-2-42.7(c). As defined in Ind. Code § 8-1-2.5-2, Petitioner is an "energy utility" and its electric service constitutes "retail energy service" as defined in Ind. Code § 8-1-2.5-3. Petitioner elects to become subject to the provisions of Ind. Code §§ 8-1-2.5-5 and 8-1-2.5-6, to the extent necessary. Accordingly, this Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. **<u>Petitioner's Organization and Business</u>.** Petitioner is a public utility incorporated under Indiana law with its principal office located at 211 NW Riverside Drive, Evansville, Indiana. Petitioner is engaged in the business of rendering retail electric service solely within the State of Indiana under duly acquired indeterminate permits, franchises, and necessity certificates. CEI South owns, operates, manages, and controls, among other things, plant, property, equipment, and facilities (collectively, the "Utility Properties") that are used and useful for the production, storage, transmission, distribution, and furnishing of electric service to approximately 150,000 electric consumers in southwestern Indiana. Its service territory is spread throughout Pike, Gibson, Dubois, Posey, Vanderburgh, Warrick, and Spencer counties.

3. **<u>Rate Base and Existing Rates</u>.** The net original cost of Petitioner's rate base on December 31, 2023, as adjusted, was projected to be approximately $1,827,211,874. The net original cost of Petitioner's rate base in service on December 31, 2024, as adjusted, was projected to be approximately $1,930,379,152. The net original cost of Petitioner's rate base in service on December 31, 2025, as adjusted, is projected to be approximately $2,820,468,760. Further, in order to properly serve the public located in its service area and to discharge its duties as a public utility, Petitioner continues to make numerous additions, replacements, and improvements to its utility systems.

Petitioner's existing base rates and charges for electric utility service were established in its 30-day filing #50171, effective June 1, 2018, pursuant to the Commission's February 16, 2018 order in Cause No. 45032, its investigation into the impacts on Indiana utilities and customers resulting from the December 22, 2017 Tax Cuts and Jobs Act of 2017 ("TCJA"), as further reduced in Petitioner's 30-day filing #50548, effective July 1, 2022, to give effect to the repeal of the Utility Receipts Tax. The rates approved effective June 1, 2018 and July 1, 2022, reduced CEI South's existing base rates and charges for electric utility service established in its most recent retail base rate case order issued on April 27, 2011, in Cause No. 43839. More than 15 months have passed since the filing date of Petitioner's last request for a general increase in its basic rates and charges.

Pursuant to Ind. Code § 8-1-2-42(d), CEI South files a quarterly Fuel Adjustment Clause ("FAC") proceeding in Cause No. 38708 FAC XXX, to adjust its rates to account for fluctuations in its fuel and purchased energy costs.

CEI South files an annual proceeding in Cause No. 43405 DSMA XX to recover, via its approved Demand Side Management Adjustment ("DSMA"), demand side management costs, including costs associated with the direct load control inspection and maintenance program, performance incentives, and lost margins.

CEI South files an annual proceeding in Cause No. 44909 CECA XX to recover via its approved Clean Energy Cost Adjustment ("CECA") eligible costs of approved clean energy projects under Ind. Code ch. 8-1-8.8, including (a) engineering and project management, management and administration, permitting, contractor site preparation, equipment, and installation costs during construction; and (b) depreciation expense, post-in-service carrying costs ("PISCC"), taxes, and operation and maintenance ("O&M") expense once the projects are placed in service. CEI South's current CECA mechanism includes a component to pass back credits resulting from the Inflation Reduction Act of 2022 ("IRA"). As discussed below, CEI South proposes to remove this component from the CECA mechanism and include it in a separate TAR. In addition, CEI South uses the CECA mechanism to pass on to customers revenues from the sale of renewable energy credits ("RECs") related to CEI South's various renewable energy projects.

CEI South files annual Environmental Cost Adjustment ("ECA") proceedings in Cause No. 45052 ECA XX to effectuate timely recovery of 80% of its federally mandated costs (as defined by Ind. Code § 8-1-8.4-2) attributable to the following five compliance projects: (a) federally mandated requirements related to CEI South's Culley Unit 3 Generating Station ("Culley 3 Project"); (b) clean coal technology projects at CEI South's Culley Unit 3 and Warrick Unit 4 (collectively the "MATS Projects"); (c) federally mandated requirements to close CEI South's A.B. Brown ash pond ("Brown Pond Project"); (d) federally mandated compliance projects including a dry fly ash loading facility ("Dry Ash Compliance Project") and federally mandated lined ponds at the A.B. Brown and F.B. Culley generating stations to handle coal-pile runoff, flue gas desulfurization wastewater, and other flows such as stormwater and landfill leachate in compliance with the EPA's coal combustion residuals ("CCR") rules ("Pond Compliance Project") (collectively, "CCR Compliance Projects"); and (e) federally mandated requirements to close by removal ("CBR") CEI South's F.B. Culley east ash pond (the "CBR Project").[11]

CEI South files annual Midcontinent Independent System Operator ("MISO") Cost and Revenue Adjustment ("MCRA") proceedings in Cause No. 43354 MCRA XX to recover costs associated with nonfuel-related MISO Day 1, Day 2, and Ancillary Services Market costs. CEI South has proposed updates for the MCRA as described in the direct testimony of Matthew A. Rice.

CEI South files annual Reliability Cost and Revenue Adjustment ("RCRA") proceedings in Cause No. 43406 RCRA XX to track the differences between certain actual costs and revenues and the amounts of those costs and revenues included in CEI South's base rates. RCRA cost and revenue components include the non-fuel component of purchased power, cost of Environmental Emission Allowances ("EEAs"), Interruptible Sales billing credits, the retail sharing portion of Wholesale Power marketing margins, the margin from Municipal Wholesale Sales, and the retail portion of the margin from EEA sales (net of cost). CEI South has proposed updates for the RCRA as described in the direct testimony of Matthew A. Rice.

Pursuant to the Commission's September 20, 2017 order in Cause No. 44910, CEI South files a semi-annual proceeding in Cause No. 44910 TDSIC XX to recover 80% of approved capital expenditures and transmission, distribution, and storage system improvement costs incurred in connection with CEI South's TDSIC Projects through its transmission, distribution and storage system improvement charges ("TDSIC") Rider. CEI South's current TDSIC mechanism includes a component to pass back credits resulting from changes in the federal tax rates under the TCJA. As discussed below, CEI South proposes to remove this component from the TDSIC mechanism and include it in the TAR. CEI South's Cause No. 44910 TDSIC Plan expired December 31, 2023, and CEI South's new TDSIC Plan was approved in Cause No. 45894 on December 27, 2023.

As a result of the Commission's financing Order in Cause No. 45722, dated January 4, 2023, CEI South was authorized to implement, collect, and receive Securitization Charges associated with the securitization of A.B. Brown Units 1 and 2 pursuant to its Securitization of Coal Plants Tariff. Pursuant to that financing order, the accumulated deferred income taxes ("ADIT") associated with the retiring A.B. Brown Units 1 and 2 are segregated from all other ADIT and not included in the calculation of Petitioner's capital structure or otherwise used in finding CEI South's authorized return in future rate cases. The financing order also established a Securitization ADIT Credit tariff to provide an annual credit to customers for the ADIT associated with A.B. Brown Units 1 and 2. In addition, the financing order required that the excess ADIT associated with A.B. Brown Units 1 and 2 be amortized and returned to customers over the life of the related Securitization Bonds. The excess accumulated deferred income taxes ("EADIT") resulting from the TCJA is being flowed back to customers via the TDSIC. As described below, CEI South is proposing to continue to flow back this EADIT over the life of the bonds through the new TAR instead of the TDSIC. The Securitization Rate Reduction ("SRR") tariff was a temporary rider established in Cause No. 45722 to provide customers with a credit for A.B. Brown net plant.

[11] CEI South's request for a Certificate of Public Convenience and Necessity for the CBR Project was pending when this Cause was filed but has since been approved by the Commission's February 7, 2024 order in Cause No. 45903.

CEI South proposes to zero out (subject to variances) the SRR tariff in customer rates in this case, as the A.B. Brown Units 1 and 2 will no longer be included in base rates.

4. **Test Year.** As authorized by Ind. Code § 8-1-2-42.7(d)(1) ("Section 42.7"), Petitioner proposed a forward-looking test period using projected data. As provided in the Commission's December 28, 2023 and January 17, 2024 Docket Entries, the test year to be used for determining Petitioner's projected operating revenues, expenses, and operating income shall be the 12-month period ending December 31, 2025. The historical base period is the 12-month period ending December 31, 2022.

5. **CEI South's Requested Relief.** In its case-in-chief, Petitioner requested Commission approval of an overall increase in rates and charges for electric service that would produce additional electric revenues of approximately $118,757,693, which would reflect an overall revenue increase of 16.02% from the rates that would have been in effect had this case not been filed. As detailed in its case-in-chief, Petitioner also requested Commission approval of a new schedule of rates and charges, general rules and regulations, and riders applicable to electric utility service, revised depreciation rates applicable to electric and common plant in service; approval of a mechanism to modify rates prospectively for changes in federal or state income tax rates; and other necessary and appropriate accounting relief. On rebuttal, Petitioner revised its proposed revenue requirement increase to $115,445,697. In settlement, the proposed revenue requirement increase was further revised to $80,009,617.

Petitioner's current electric depreciation rates were approved by the Commission's order in Cause No. 43111 on August 15, 2007, and subsequently re-authorized (with a modification to the depreciation rate applicable to the Blackfoot landfill gas generating station) in Cause No. 43839 (April 27, 2011). Petitioner's current common plant depreciation rates were approved by the Commission's order in Cause No. 45447 on October 6, 2021. Depreciation rates for Petitioner's combustion turbine project (the "CT Project") and Posey Solar project ("Posey Solar") were approved by the Commission's orders in Cause No. 45564 on June 28, 2022, and Cause No. 45847 on September 6, 2023, respectively. Petitioner is seeking approval of new electric and common plant depreciation rates in this Cause, based on the study sponsored by witness Spanos, except that the rates for the CT Project and Posey Solar shall remain unchanged from what was approved in Cause Nos. 45564 and 45847, respectively.

Petitioner, in its case-in-chief, made additional requests for the approval of new riders, including a new TAR, a new Green Energy Rider ("Rider GE"), an aggregation demand response rider ("Rider ADR"), a CPP pilot program, regulatory accounting treatment for third-party CCAs, an ARP for a waiver from 170 IAC 4-1-16(f) to allow remote disconnections for non-payment, and other requests, all as more particularly described elsewhere in this order. Pet. Ex. 1, Attachment RCL-1 (Petition).

6. **Overview of the Evidence.**

A. CEI South's Case-in-Chief. Mr. Leger described CEI South's electric utility operations. Pet. Ex. 1 at 3-4. He discussed the guiding principles that inform CEI South's provision of electric service, and the challenges CEI South has faced. He discussed the primary drivers of CEI South's request for rate relief in this proceeding, primarily the TDSIC statutory requirements, rate base growth, and the industry transformation. He also explained the reasons CEI South's requested rate increase is reasonable and necessary. He discussed the Five Pillars of reliability, resiliency, stability, affordability, and environmental sustainability codified in Ind. Code § 8-1-2-0.6 as the framework to be used to guide decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs. He discussed how they have been considered by CEI South when developing its rate proposal. He also explained how the Five Pillars can sometimes conflict and what CEI South has done to specifically address affordability, including customer assistance and federal funding.

Ms. Behme supported CEI South's revenue requirement, explained the forecasted 2025 test year for ratemaking purposes and the pro forma adjustments to the test year, and sponsored the details around the phased in approach to implementing rates under Ind. Code § 8-1-2-42.7 and Commission General Administrative Order 2013-05. She also supported certain requests for deferred accounting treatment. Pet. Ex. 2.

Ms. Gray discussed and supported the 2025 unadjusted test year forecast. She also supported the 2024 – 2025 unadjusted Income Statement and Balance Sheet CEI South used in the development of the revenue requirement calculation. Pet. Ex. 3.

Mr. Rawlinson discussed CEI South's overall approach to transmission and distribution capital planning. He also provided information on transmission and distribution capital expenditures completed or planned from June 30, 2009, the rate base cutoff date in CEI South's last electric rate case (Cause No. 43839) (the "43839 rate base cutoff"), through the end of the 2025 test year. He also provided information on CEI South's electric system reliability performance. Pet. Ex. 4.

Ms. Folz discussed CEI South's ongoing reliability initiatives related to Advanced Metering Infrastructure ("AMI") capabilities and supported CEI South's request for ARP treatment and a waiver of requirements under 170 IAC 4-1-16(f). Ms. Folz further described CEI South's electric transmission system, substation, and underground network inspection programs. Additionally, she provided an overview of CEI South's Transmission System Operations and MISO affairs. Pet. Ex. 5.

Mr. Maurer described CEI South's commitment to electric service reliability and its operations and maintenance ("O&M") programs, including its overhead and underground maintenance programs, Vegetation Management Program, and Emergency Operations Plan. Pet. Ex. 6.

Mr. Bradford discussed CEI South's Generation Transition Plan and provided a summary of the material generation capital investments that have been made since the 43839 rate base cutoff through the end of the 2025 test year. He described CEI South's plan to give its customers 100%

of the Wholesale Power Market ("WPM") sales margins opportunity rather than the present sharing mechanism and provided an update on CEI South's Urban Research Living Center ("ULRC") project. Pet. Ex. 7.

Mr. Bahr described the information technology ("IT") services provided by the Service Company to CEI South, along with major enterprise-wide programs and associated charges. Pet. Ex. 8.

Mr. Wood described the services provided, and costs allocated, to CEI South by the Service Company and Vectren Utility Holdings, LLC ("VUH") and how the allocation process is managed. He also described the Service Level Agreements between Service Company and CEI South; the affiliate agreement between CEI South and VUH; the annual budgeting process; and controls in place to ensure that costs are managed, controlled, and billed properly. Pet. Ex. 9.

Ms. Williford discussed and supported CEI South's employee compensation and benefits. Pet. Ex. 10.

Mr. Kopp sponsored CEI South's Decommissioning Cost Study for CEI South's power generation assets. Pet. Ex. 11.

Mr. Spanos supported the updated electric and common plant depreciation study and new electric and common plant depreciation accrual rates. Pet. Ex. 12.

Ms. Bulkley supported CEI South's requested return on equity ("ROE") and appropriateness of the capital structure and projected cost of debt. Pet. Ex. 13.

Mr. Jerasa presented the components of CEI South's capital structure and the reasonableness of their projected balances and weighting. In addition, he supported CEI South's projected cost of debt and the overall weighted average cost of capital. Pet. Ex. 14.

Ms. Story discussed the impact of the IRA and addressed the corporate alternative minimum tax ("CAMT") and CEI South's proposed TAR. Ms. Story also supported the computation of the income tax expense included in CEI South's cost of service determination and addressed the accumulated deferred income taxes and excess accumulated deferred income tax regulatory liability balances included in CEI South's cost of capital calculation. She sponsored the property tax forecast and the Medicare Part D regulatory liability and associated amortization adjustment. Pet. Ex. 15.

Mr. Russo supported the projected class-level 2025 Test-Year sales and customer forecasts. Pet. Ex. 16.

Mr. Forshey discussed CEI South's Large Electric customers and the importance of attracting new large customers to southwestern Indiana. He provided support for proposed new and modified riders and CEI South's Energy Efficiency and Demand Side Management ("DSM") initiatives. Pet. Ex. 17.

Mr. Taylor presented the results of the Cost-of-Service Study ("COSS") and rate design, and discussed its effect on rates. Pet. Ex. 18.

Mr. Rice sponsored the proposed rates within the Tariff and proposals associated with new and existing adjustment mechanisms. He described the proposed Phase 1, Phase 2, and Phase 3 rate implementation proposals and supported CEI South's request for a Green Energy Rider (Rider GE) as well as a CPP pilot. Pet. Ex. 19.

Petitioner also provided its Financial Exhibit in support of its requested relief in this proceeding in Excel (Pet. Ex. 20) and PDF formats (Pet. Ex. 21).

B. OUCC and Intervenors' Cases-in-Chief. The OUCC and intervenors proposed several adjustments to CEI South's proposed revenue requirements and took issue with numerous other components of CEI South's case-in-chief and proposed rate increase.

i. OUCC's Case-in-Chief. The OUCC proposed an ROE of 8.8% (reduced from 9.00% based on the OUCC's claims of issues with reliability, customer satisfaction, and challenges faced by OUCC in analyzing Petitioner's requests). Pub. Ex. 10 at 3 and Pub. Ex. 1 at 25. The OUCC also recommended certain operating revenue and expense adjustments. *See, e.g.*, testimony of OUCC witnesses Eckert (Pub. Ex. 1), Latham (Pub. Ex. 2), Lantrip (Pub. Ex. 3), Baker (Pub. Ex. 4), Compton (Pub. Ex. 5), Stull (Pub. Ex. 6), Armstrong (Pub. Ex. 7), and Krieger (Pub. Ex. 9). After corrections to testimony, the OUCC ultimately concluded that Petitioner justified an increase of $48.315 million. Pub. Ex. 1 at 2. The OUCC further recommended the Commission deny CEI South's proposed increases to its monthly customer charges for residential and small business customers and approve modifications to certain depreciation rates. Pub. Ex. 12 at 71; Pub. Ex. 11 at 3.

Mr. Eckert testified regarding the OUCC's evaluation and analyses of Petitioner's revenue requirement requests contained in its case in-chief. He identified and addressed the OUCC's concerns related to affordability, risk assessment, and storm response. He also addressed the Five Pillars of affordability, reliability, resiliency, stability, and environmental sustainability and explained how cost trackers are shifting the risk of operating expense increases and capital expenditures from CEI South to ratepayers. He explained and supported specific adjustments and recommendations regarding certain CEI South requests for fuel cost, fuel inventory, Culley 3 outage capital expenditures, securitization expense, and amortization expense. Pub. Ex. 1.

Mr. Latham sponsored the OUCC's overall revenue requirement recommendation and testified regarding revenue requirement adjustments. He incorporated the impact of the other OUCC witnesses' recommendations in his revenue requirement calculations. He presented the OUCC's capital structure analysis and recommended a 6.29% weighted average cost of capital ("WACC") that includes the ROE OUCC witness Dellinger recommends. In addition, he calculated the OUCC's depreciation expense and recommended accumulated depreciation using Mr. Garrett's proposed depreciation rates. Pub. Ex. 2.

Mr. Lantrip addressed CEI South's request to embed in base rates Petitioner's CECA and RCRA investments. He recommended the Commission deny Petitioner's request to include approximately $219,348 of costs related to the CECA's ULRC. Witness Lantrip also discussed CEI South's affiliate company arrangements with CenterPoint Shared Services and VUH. Pub. Ex. 3.

Ms. Baker addressed Petitioner’s adjustments to payroll expenses, including incentive benefits, and deferred Medicare tax liability. She recommended the Commission: 1) deny Petitioner’s requested competitive pay adjustment; and 2) deny Petitioner’s requested $1,737,007 in deferred Medicare tax liability. Pub. Ex. 4.

Mr. Compton recommended 1) rate case expense be shared equitably between shareholders and ratepayers because shareholders will benefit from new rates; 2) an adjustment to sponsorship expense; 3) removal of CEI South’s IT investment and related O&M expenses from the revenue requirement; and 4) denial of CEI South’s requested accounting treatment for cloud computing arrangement costs. Mr. Compton testified regarding the difficulties he had reviewing CEI South’s case-in-chief. Pub. Ex. 5.

Ms. Stull addressed CEI South’s proposals regarding 1) the TAR; 2) recovery of a return on any increase or decrease to the balance of the tax regulatory asset related to CAMT occurring between rate cases; 3) rate increase implementation before the start of CEI South’s forward-looking test year; 4) implementation of interim rate increases between Phases 2 and 3 to reflect projected rate base additions; and 5) the process for implementing rates in each phase of the proposed rate increase. She discussed the OUCC’s concerns regarding CEI South’s presentation of its accounting schedules and revenue requirement in its case-in-chief, including a lack of evidence support Petitioner’s requests and CEI South’s non-compliance with GAO 2013-05 and 2015-05. Pub. Ex. 6.

Ms. Armstrong addressed several environmental-compliance-cost-related rate base items and O&M expenses CEI South included in its rate request, including 1) emission allowance inventory; 2) test year emission allowance expense; 3) the Culley East Ash Pond Closure by Removal Project costs; 4) additional costs CEI South incurred with respect to the ULRC; 5) unexplained land acquisitions around the A.B. Brown Generating Plant; and 6) CEI South’s adjustment to decrease test year Integrated Resource Planning (“IRP”) expense. Pub. Ex. 7.

Mr. Wright discussed CEI South’s Rider GE and Rider ADR proposals and recommended changes to Rider GE and associated tariff language to ensure the program does not negatively affect affordability for ratepayers. He recommended the denial of Rider ADR based on a lack of basic, critical information on how the program will function. Pub. Ex. 8.

Mr. Krieger analyzed CEI South’s capital investment request and discussed how project managers and project engineers distinguish between capital investment and maintenance costs. He described how an approved prudent capital investment may not be prudent in practice and recommended a $150.7 million reduction to the Steam Production Plant costs. Pub. Ex. 9.

Mr. Dellinger recommended an ROE of 9.00% for CEI South. Pub. Ex. 10.

Mr. Garrett analyzed CEI South’s depreciable assets and developed reasonable depreciation rates and annual accruals. Specifically, he recommended the Commission: 1) remove $1.6 million in contingency costs; 2) adjust Transmission and Distribution (“T&D”) service lives which reduces depreciation expense by $2.1 million; and 3) adjust net salvage rates for several T&D accounts by $1.4 million. Pub. Ex. 11.

Dr. Dismukes addressed Petitioner's proposed allocated cost-of-service study ("ACOSS"), revenue distribution, rate design, rate adjustment proposals, critical peak pricing, and related tracker mechanisms. He recommended CEI South's current residential and small commercial customer charges remain unchanged. He also recommended elimination of the current fixed component for monthly TDSIC charges for Rates RS, SGS, and water heating service customers. Pub. Ex. 12.

Ms. Paronish discussed CEI South's remote disconnection proposal, bill issues, and certain aspects of Petitioner's CPP proposal. Pub. Ex. 13.

ii. **Industrial Group Case-in-Chief.** Industrial Group witness Gorman recommended adjustments to Petitioner's revenue requirement. He testified that CEI South's claimed three-phase revenue increase is overstated by $29.5 million. IG Ex. 1 at 3. He took issue with the number of customers and the sales forecast used to calculate the Phase 3 revenue deficiency. He recommended an ROE of 9.20% which produces an overall return of 6.46%. He also rejected the inclusion of the prepaid pension asset in CEI South's capital structure. Mr. Gorman proposed a shorter amortization period to return Indiana EADIT and recommended removing a portion of the incentive compensation costs from cost of service. He recommended the Commission deny CEI South's request to establish a regulatory asset for future third-party CCAs, recommended removing the full revenue requirement impact from the test year for all capital costs associated with the 2022-2023 Culley 3 outage, if the Commission ultimately finds that CEI South was imprudent in Cause No. 38708 FAC 137 S1, and recommended the Commission reform the limitation of liability provision in CEI South's tariff.

Industrial Group witness York testified that CEI South's allocation of production costs on the basis of a 4-Coincident Peak ("4CP") demand is consistent with CEI South's historic practice, cost-causation, and sound ratemaking, and should be approved. IG. Ex. 2 at 3. She said CEI South's proposal to deviate from its method of allocating transmission costs by shifting to a 12-Coincident Peak ("12CP") basis should be rejected. In addition, she said CEI South's ACOSS does not accurately measure its cost of providing service to each customer class, due to an inaccurate classification and allocation of distribution costs. She explained that CEI South's ACOSS fails to classify a portion of costs included in Federal Energy Regulatory Commission ("FERC") Accounts 364, 365, 367, and 368 as customer related. She recommended an alternate revenue apportionment based on the results of her modified ACOSS, which reflects a more reasonable and correct classification and allocation of distribution costs in FERC Accounts 364, 365, 367, and 368, and uses a 4CP allocation of transmission costs. She said CEI South's FAC should be modified to recognize the capacity component of renewable resource costs. She explained that the capacity component of renewable resource costs should be allocated across rate classes using the production demand allocator established in CEI South's most recent rate case, and the renewable resource capacity costs should be recovered from Large Power Service ("LP"), Backup, Auxiliary, and Maintenance Power Service ("BAMP"), and High Load Factor ("HLF") customers using a demand charge.

iii. **CAC's Case-in-Chief.** CAC witness Olson discussed the reaction of the public and elected leaders to Petitioner's rate request. CAC Ex. 1. He presented resolutions and letters from impacted southwestern Indiana local units of government as attachments and cited local news articles. *Id.*, Attachments KO-2 and KO-3. He recommended the Commission strongly consider the testimony presented in the field hearings in this Cause and reject Petitioner's proposals in this proceeding.

CAC witness Inskeep addressed the utility unaffordability crisis generally and specifically for CEI South customers. He testified about certain revenue requirement issues, rate design issues and the fixed charge component in the TDSIC rider, the proposed Cloud Computing request, the various demand response proposals, cost allocation for the Texas Gas Transmission ("TGT") pipeline, CEI South's request to disconnect customers remotely, and miscellaneous charges and fees. CAC Ex. 2.

CAC witness Barnes addressed base rate case and tracker allocation, rate impact mitigation, special contract issues, and residential rate issues. CAC Ex. 3.

iv. Evansville and SABIC's Cases-in-Chief. Evansville Council witness Heronemus provided a copy of the C-2024-05 Resolution of the Common Council of the City of Evansville and said it is the Council's position and request that the Commission reject Petitioner's requested rate increase. Evansville Council Ex. 1 at 1, Zachary Heronemus Attachment.

SABIC witness Coyle explained the service SABIC receives from CEI South and identified concerns with CEI South's proposed rates that would be charged to Rate Schedule Base, BAMP customers. She also identified concerns with CEI South's proposed ACOSS. SABIC Ex. 1 at 4.

C. CEI South Rebuttal. Mr. Leger responded to direct testimony from the OUCC, CAC, the Evansville Council, and comments from the public field hearing and addressed affordability. Pet. Ex. 1-R.

Ms. Behme responded to the direct testimony of various witnesses from the OUCC, CAC, IG, and SABIC. She addressed the changes to CEI South's revenue requirement occurring from corrections identified by CEI South as well as the changes from accepted positions recommended by intervening parties. She responded to certain recommendations of disallowance or treatment that CEI South does not agree with, including certain plant in service and corresponding accumulated reserve suggestions; trade association expenses; rate case expenses; shared services adjustment; deferred liability adjustment; regulatory asset for cloud computing arrangements; phase implementations; and transparency and case presentations. She also identified and described Petitioner's Exhibit No. 20-R, which is the revenue requirement model. She sponsored the actual rate base and capital structure as of December 31, 2023. Pet. Ex. 2-R.

Mr. Rawlinson addressed concerns raised by OUCC witness Eckert regarding CEI South's reliability, resilience, and stability (as they relate to the Five Pillars). He also addressed concerns raised by SABIC witness Coyle regarding CEI South's cost allocation and rates for Backup Transmission Service. Pet. Ex. 4-R.

Ms. Folz responded to the direct testimony of OUCC witness Eckert regarding his recommendations on storm response communications and reporting. She also responded to the direct testimony of OUCC witness Paronish and CAC witness Inskeep regarding their recommendations on CEI South's proposed remote disconnection for nonpayment program. Pet. Ex. 5-R.

Mr. Bradford responded to IG witness Gorman, who recommended that the Commission deny recovery of specific Power Generation capital investments; to OUCC witness Eckert, who recommended CEI South adjust the fuel inventory level; and to OUCC witness Armstrong who recommended the Commission deny recovery of the remaining ULRC project costs. In addition, Mr. Bradford responded to OUCC witness Baker's statement that CEI South has not had issues with filling and maintaining staffing positions. Pet. Ex. 7-R.

Mr. Bahr responded to OUCC witness Compton's recommendation that the Commission disallow IT investments in rate base along with test year costs related to the SAP S/4HANA Transformation Program and Cloud Computing Arrangement. Pet. Ex. 8-R.

Ms. Williford responded to Ms. Baker and Mr. Gorman regarding certain compensation costs CEI South is seeking to recover. She testified that CEI South's requested levels of compensation costs are reasonable and necessary, given that the compensation and benefits offered by CNP[12] are necessary to attract and retain employees at all levels. Pet. Ex. 10-R.

Mr. Spanos responded to OUCC witness Garrett and addressed adjustments proposed by the OUCC to the depreciation expense calculated in CEI South's Depreciation Study. These adjustments include eliminating a contingency factor in the calculation of decommissioning costs and making changes to service life and net salvage estimates to a few transmission and distribution accounts. Pet. Ex. 12-R.

Ms. Bulkley responded to the direct testimony of OUCC witnesses Dellinger and Eckert, Mr. Gorman, and Mr. Inskeep regarding the just and reasonableness of Petitioner's proposed ROE and the appropriate capital structure for CEI South in this proceeding. Pet. Ex. 13-R.

Mr. Jerasa responded to Mr. Gorman's commentary on CEI South's equity in its capital structure and his recommendation that the prepaid pension asset and other post-employment benefits be removed from the capital structure. His testimony also responded to OUCC witness Stull regarding the CAMT impact on credit metrics. Pet. Ex. 14-R.

Ms. Story responded to Ms. Stull's recommendation that CEI South's proposal to include the CAMT in its proposed TAR should be denied. She also responded to Ms. Stull's and Mr. Gorman's recommendations regarding Indiana state income tax EADIT. Pet. Ex. 15-R.

Mr. Russo responded to Mr. Gorman's recommendation that the 2025 test-year residential average use should be 866 kWh per month and commercial average use 5,106 kWh per month. Pet. Ex. 16-R.

Mr. Forshey responded to OUCC witness Wright's concerns with the proposed Rider ADR, and the concerns of OUCC witnesses Paronish and Dismukes related to the Critical Peak Pricing Pilot. He also responded to SABIC witness Coyle's direct testimony regarding Section 24 contracts. Pet. Ex. 17-R.

[12] CNP is used in Ms. Williford's testimony to refer to CenterPoint Energy, Inc. and its affiliates, which include the Service Company and CEI South. Pet. Ex. 10 at 1; Pet. Ex. 10-R at 1.

Mr. Taylor addressed specific sections of the direct testimony submitted by other parties and elaborated on the updates made to CEI South's ACOSS and the integration of CEI South's revised revenue requirement. He covered the areas of ACOSS, revenue distribution and special contract revenue treatment, rate design and customer charge, and tracker allocation. Pet. Ex. 18-R.

Mr. Rice addressed concerns raised by the public at the field hearing; responded to testimony from other parties regarding affordability; responded to suggestions from OUCC witness Wright regarding the proposed Green Energy Rider; responded to the OUCC's opposition to Rider ADR; responded to OUCC objections to the CPP Pilot; addressed customer satisfaction concerns; responded to issues raised by SABIC witness Coyle concerning Rate BAMP; and addressed a number of other isolated issues raised by various witnesses. Pet. Ex. 19-R.

Mr. Cunningham responded to Mr. Krieger's recommendation to reduce rate base by $104.7 million in Steam Production Plant capital investment.

D. Cross-Answering Testimony. Certain intervenors filed cross-answering testimony on various topics. IG witness York responded to concerns about rate affordability raised by Dr. Dismukes on behalf of the OUCC and Mr. Barnes on behalf of the CAC. She responded to Dr. Dismukes's and Mr. Barnes's recommendations on the allocation of production and distribution-related investment cost in CEI South's ACOSS, as well as their recommendations with respect to the apportionment of any revenue requirement increase granted in this case. She responded to CAC witness Inskeep regarding his request for the Commission to direct CEI South to implement an Affordable Power Rider, and to fund such a program via an energy charge for all customers. She addressed the recommendations of CAC witness Barnes regarding the allocation of costs within certain tracker mechanisms, including costs associated with the TGT Pipeline, the ECA, and the CECA. She also responded to Mr. Barnes's recommendations regarding Section 24 contract customers. IG Ex. 3 at 2-29.

CAC witness Inskeep provided cross-answering testimony concerning other parties' positions on overarching issues and demand response. CAC Ex. 4 at 1-15. CAC witness Barnes provided cross-answering testimony regarding IG witness York, SABIC witness Coyle, and OUCC witness Dismukes positions on cost allocation, reasonable methodology for rate impact mitigation, and the appropriate classification of distribution system costs. CAC Ex. 5 at 1-45.

7. Settlement Agreement; Commission Discussion and Findings.

A. Overview.

i. Settling Parties' Testimony. CEI South witness Rice sponsored the Stipulation and Settlement Agreement ("Settlement Agreement" or "Settlement") entered into by the CEIS Industrial Group, SABIC, and CEI South. He opined that the Settlement Agreement represents reasonable resolutions of all issues in this proceeding and supports a Commission order adopting the terms. Pet. Ex. 19-S at 1.

Mr. Rice provided the following outline of the Settlement Agreement:

- Section A provides background on CEI South's current rates and charges and the status of the rate case pending under this Cause.

- Section B.1 discusses the two phases in which CEI South will implement its authorized increase to base rates and charges for electric utility service.

- Section B.2 addresses the stipulated revenue requirement, revenue increase and authorized net operating income ("NOI").

- Section B.3 discusses the resolution of issues impacting the agreed upon revenue requirement and resulting rate increase, including: (a) original cost rate base; (b) other rate base items; (c) capital structure; and (d) fair return.

- Section B.4 addresses the resolution of issues related to depreciation rates and amortization expense, respectively.

- Section B.5 addresses the resolution of issues related to pro forma revenues and expenses, including: (a) base cost of fuel, (b) interruptible sales billing credits, (c) capacity purchase costs, and (d) O&M expense.

- Section B.6 addresses the stipulation and agreement for the accounting treatment for cloud computing costs.

- Section B.7 describes proposed riders, including (a) CPP Pilot, Rider ADR, and Green Energy Rider and (b) TAR.

- Section B.8 describes other tariff matters, including: (a) Interruptible Contract ("IC") and Interruptible Option ("IO") Riders and (b) limitation of liability provision in the tariff.

- Section B.9 addresses Petitioner's proposed ARP for Remote Disconnection.

- Section B.10 addresses customer protection provisions, including: (a) Low Income Home Energy Assistance Program ("LIHEAP") Customer Deposits, (b) residential late payment charge, (c) LIHEAP Qualified Participant fees and reporting, and (d) disconnections / reconnection.

- Section B.11 discusses CEI South's commitment to collect data on residential customer housing types and analyze cost differentials between single- and multi-family rate residential customers in advance of its next rate case.

- Section B.12 discusses CEI South's commitment to customer bill transparency.

- Sections B.13 and B.14 address cost of service, cost allocation, and rate design.

- Section B.15 discusses other disputed items, including BAMP rates and all other items.

- Section C addresses the effect, scope, and approval of the stipulation.

Pet. Ex. 19-S at 5-6.

Under the Settlement Agreement, the Settling Parties have agreed that CEI South's requested rate increase should be reduced significantly below CEI South's request. The revenue requirement increase in the Settlement Agreement is closer to that proposed by the OUCC in its case-in-chief than CEI South's rebuttal position and lower than the Industrial Group's litigation position. The Settlement Agreement makes multiple other changes to CEI South's requested relief in this Cause. As reflected in Section B.2 of the Settlement Agreement and Settlement Agreement Appendix A, the Settling Parties have agreed to a net revenue increase of $80,009,617, which is a decrease of $38,748,076 from the amount requested in Petitioner's original case-in-chief, and an ROE of 9.8%.

Mr. Rice expressed his opinion that the Settlement Agreement is in the public interest, reasonably resolves all issues in this case without further expenditure of the time and resources of the Commission and the parties in the litigation of these matters and should be approved in its entirety by the Commission, without modification. Mr. Rice stated that the Settlement Agreement represents the result of arm's-length negotiations by stakeholders with differing views on the issues raised in this case. He explained that Settling Parties' experts were involved with legal counsel in the development of both the conceptual framework and the specific terms of the Settlement Agreement. The Settling Parties devoted many days to discussions, collaborative exchange of information, and settlement negotiations.

Mr. Rice stated that while the Settling Parties agree and represent that the Settlement resolves all issues in this case, three parties — the OUCC, the CAC and the Evansville Council — have not joined in the Settlement Agreement. Pet. Ex. 19-S at 2. He testified that the non-settling parties were all copied on communications and terms throughout the negotiation of the Settlement Agreement and were given the opportunity to weigh in on the terms of the settlement during these negotiations. Mr. Rice noted that, while these parties did not join the Settlement Agreement, the Settling Parties recognized the issues they raised in this proceeding and addressed those concerns by including many of the positions from the OUCC and CAC in the Settlement terms. Mr. Rice also testified CEI South reviewed recent settlements with other Indiana investor-owned utilities ("IOUs") and included many consumer protections listed in those agreements.

Mr. Rice testified that it is important to recognize that the Settlement Agreement is presented as a complete negotiated package of terms that, taken as a whole, reflects compromise and the give and take of negotiations. He explained Section C.1 makes clear that the Settlement Agreement is the result of negotiations and compromise reached during those negotiations, and that neither the making of the Settlement Agreement nor any of its provisions shall constitute an admission or waiver by any Settling Party in any proceeding other than this case, now or in the future, nor shall it be cited as precedent. He opined that the Settlement Agreement is supported by and within the scope of the evidence presented by the Settling Parties. He stated that, taken as a whole, the Settlement Agreement represents the result of extensive, good faith, arm's-length negotiations reflecting a fair and balanced outcome of the rate case issues reached among parties having divergent interests. CEI South's and the other Settling Parties' proposals were modified through the negotiations. The Settlement Agreement reasonably addresses the concerns raised in this proceeding, limits controversy, and provides a balanced, cooperative outcome of the issues in this Cause. He stated CEI South respectfully asks the Commission to issue an order approving the Settlement Agreement in its entirety, without modification, so that new rates may be placed into effect at the earliest possible time after the beginning of the test year.

CEI South witness Behme presented Petitioner's Exhibit No. 20-S, which provides CEI South's revised revenue requirement request based upon the terms of the Settlement Agreement. Where Petitioner's Exhibit No. 20-S does not reflect a change, the position, as filed in the original case in chief, as modified on rebuttal where applicable, is adopted under the Settlement Agreement. Pet. Ex. 2-S.

CEI South witness Jerasa supported Section B.3 of the Settlement Agreement addressing CEI South's original cost rate base, capital structure, and fair return. He stated the Settling Parties agree CEI South's authorized ROE should be 9.80%, which results in a weighted average cost of capital of 6.77%. Pet. Ex. 14-S.

CEI South witness Taylor's settlement testimony addressed (1) ACOSS, (2) Revenue Distribution, and (3) Rate Design and Customer Charges and the implications and benefits for all stakeholders of the resolutions reached by the Settling Parties. Pet. Ex. 18-S.

CEIS Industrial Group witness Gorman testified in support of the Settlement Agreement, recommending its approval as a comprehensive agreement among the Settling Parties which resolves all issues raised by the parties in this rate case in a fair and reasonable manner. IG Ex. 4. He opined that the terms related to the revenue requirement are within the range of outcomes which could have resulted if this case were fully litigated. He explained the Settlement Agreement results in a reasonable revenue increase which reflects a fair return of and on capital investment made by CEI South if the utility is operated efficiently and enables CEI South to continue to provide reliable service to its customers on an economical basis. He stated the Settlement Agreement is a comprehensive agreement resolving all of the issues in the case, with each term essential to the overall reasonableness and arrived at as part of the "give and take" of the negotiating process. He recommended the Commission approve the Settlement Agreement without material change.

Industrial Group witness York also testified in support of the Settlement Agreement, describing how the Settlement resolves the cost of service and rate design issues raised in this proceeding by adopting the COSS presented by CEI South in this proceeding, with certain agreed modifications. IG Ex. 5. She opined that the cost of service and rate design terms of the Settlement Agreement operate in conjunction with the revenue terms to produce rates that are just and reasonable for all classes.

ii. OUCC and CAC Settlement Opposition Testimony. OUCC witness Eckert stated the Commission should reject the Settlement Agreement because it is not in the public interest for the reasons described in his testimony and in the testimony of the other OUCC witnesses. Pub. Ex. 1-S. He stated CEI South and the other Settling Parties have not adequately justified multiple aspects of the Settlement Agreement. He recommends the

Commission: (1) reject the Settlement Agreement among CEI South, the Industrial Group, and SABIC insofar as the Settling Parties request the Commission to approve an annual rate increase of $80.0 million; (2) reject the Settling Parties' agreed ROE of 9.80% and approve the 9.00% ROE recommended by OUCC witness Dellinger, subject to the additional modification recommended next; (3) reduce OUCC witness Dellinger's 9.00% ROE or the Commission authorized ROE by an additional 20 basis points due to continued issues with CEI South's reliability, customer satisfaction, and the "roadblocks" CEI South posed when the OUCC analyzed Petitioner's requests; (4) adhere to Indiana's policy of promoting utility investment in infrastructure while also protecting the affordability of utility service, and only approve necessary and reasonable requests required for CEI South's provision of electric service at reasonable rates; and (5) approve the other recommendations and proposals raised in his testimony and that of the OUCC's additional witnesses.

OUCC witness Compton testified that the Settlement Agreement did not adequately address the issues he raised with respect to the inclusion of certain IT investments in rate base and related operating expenses in the revenue requirement. Pub. Ex. 5-S.

OUCC witness Stull testified that the Settlement Agreement does not adequately address the issues and concerns she raised. Pub. Ex. 6-S at 2. More particularly, she discussed the Settlement Agreement's proposed treatment with respect to implementation of the TAR and reporting requirements and how it does not conform to her recommendations. She also discussed the Settlement Agreement's proposed treatment when implementing the phased rate increases, including adjustments to be made to pro forma net operating income and the information to be included in the compliance filings and urged the Commission to incorporate her recommendations in its Order. Finally, she testified that the Settlement Agreement does not address the transparency and completeness issues she raised concerning CEI South's case-in-chief.

OUCC witness Wright addressed issues and concerns with CEI South's rebuttal position, specifically with respect to Rider ADR and Rider GE. Pub. Ex. 8-S.

OUCC witness Krieger testified that the Settlement Agreement failed to adequately address issues he raised with respect to certain capital investment to be included in rate base, notwithstanding adjustments made in rebuttal and in the Settlement. In particular, he addressed the reasons he does not believe the Settlement Agreement adequately addressed the issues he raised with respect to Petitioner's capitalization of maintenance. He continued to recommend a $150.9 million reduction of capital investment in Steam Production Plant that CEI South proposes to include in rate base. He also recommended a complete audit review to ensure Petitioner's capitalization of maintenance was not more prevalent than Petitioner presented, as well as ongoing audits and a refund of excess earnings garnered by CEI South through this practice. He stated the impact of this recommendation also reduces annual depreciation and the annual revenue requirement. Pub. Ex. 9-S.

OUCC witness Dellinger testified in opposition to the ROE agreed upon in the Settlement Agreement. Pub. Ex. 10-S.

OUCC witness Dismukes filed testimony in opposition to the Settlement Agreement to address what he called the flawed provisions regarding allocated cost of service, revenue distribution, and rate design. He also included testimony on affordability generally and opposed the proposed CPP Pilot. Pub. Ex. 12-S.

OUCC witness Paronish testified in opposition to the Settlement Agreement, specifically with respect to communications with customers regarding remote disconnections, billing transparency, and the CPP Pilot. Pub. Ex. 13-S.

CAC witness Inskeep urged the Commission to deny the Settlement Agreement, stating the Settlement Agreement would impose extreme rate shock on the residential class and exacerbate affordability challenges for residential customers to benefit a handful of large industrial customers. He testified the "modest" consumer protection provisions and other terms included in the Settlement Agreement do not meaningfully alleviate these concerns. CAC Ex. 6.

CAC witness Barnes stated the Commission should reject the Settlement Agreement because it is biased in favor of the interests of industrial customers at the expense of residential customers stemming primarily from the retention of "outmoded cost allocation methods" that he says fail to reflect cost causation on CEI South's system. CAC Ex. 7 at 21. He objected to the "lack of any meaningful proposal for rate impact mitigation for residential customers and unwarranted handouts to SABIC via revisions to the BAMP tariff." *Id.*

iii. <u>Settlement Rebuttal Testimony</u>. CEI South witness Jerasa provided settlement rebuttal testimony to respond to the settlement opposition testimony of OUCC witnesses Eckert and Dellinger with respect to ROE. Pet. Ex. 14-SR.

CEI South witness Taylor addressed Settlement opposition testimony submitted by the OUCC and CAC with respect to the ACOSS, revenue distribution, and rate design and customers charges. Pet. Ex. 18-SR.

CEI South witness Rice responded to claims by the OUCC and CAC that the Settlement Agreement is one-sided, favoring large customers at the expense of affordability for residential customers. He addressed the updated affordability analyses performed by OUCC witness Dismukes and CAC witness Inskeep and responded to OUCC witness Krieger's recommendation that $150.9 million in utility plant in service be disallowed. He addressed OUCC witness Paronish's billing recommendations and provided responses to other issues raised by OUCC and CAC witnesses. Pet. Ex. 19-SR.

Mr. Rice stated his testimony and the testimony of the other Settling Parties in support of the Settlement demonstrate the efforts undertaken to balance the interests of not just the Settling Parties but all stakeholders. He stated the Settlement Agreement achieves a reasonable compromise on the issues in dispute in this Cause, even where the resolution of a particular issue might represent a benefit to parties who have chosen to oppose the Settlement Agreement. He opined that the Settlement Agreement will result in a reasonable revenue increase, fairly designed to balance the interests of CEI South and its customers, and it should be approved as in the public interest.

IG witness Gorman also filed settlement rebuttal testimony opining that the arguments raised by the OUCC and CAC boil down to an unreasonable criticism that the Settlement Agreement did not adopt the non-settling parties' litigation positions in their entirety. He explained that the fact that the non-settling parties chose not to join the Settlement does not indicate that the agreed terms are unreasonable, because the Settling Parties invited the OUCC and CAC to participate in the settlement discussions but those parties chose not to participate actively or provide substantive input on the terms. He also explained that preserving the 4CP allocation for generation and transmission plant preserves the status quo and is consistent with cost-causation. He noted that the Industrial Group agreed to a major concession with respect to foregoing its position on the Minimum System Study, namely, that allocation of distribution costs should include a customer component in FERC Accounts 364, 365, and 367. He noted that based on CEI South's as-filed revenue proposal and the Industrial Group's litigation position on cost of service, the increase to the residential class could have been as high as 24%, but under the Settlement, the residential increase will be 14.7%. IG Ex. 6.

Industrial Group witness York responded to the cost of service and rate design issues discussed in the OUCC and CAC settlement opposition testimony. IG Ex. 7.

SABIC witness Coyle addressed the settlement testimony of CAC witness Barnes regarding the Settlement terms relating to BAMP service. Ms. Coyle refuted Mr. Barnes's assertion that the Settlement Agreement will permit SABIC to avoid costs associated with historical investments that benefited SABIC before it installed its own generator. She stated that SABIC is still paying for these costs through the Base and Maintenance portion of its BAMP Service and noted the Settlement Agreement treats the Backup Service portion of BAMP Service the same as any other customer on the system who has reduced its load over time through energy efficiency or distributed generation investments. Ms. Coyle testified that Backup Service customers are required to pay for transmission service at all hours for their full contracted load, even if the customer-owned generator is serving its load.

Ms. Coyle opined that the Settlement Agreement represents a compromise between CEI South and SABIC, resulting in SABIC still paying higher than CEI South's FERC transmission rates, which represent the cost of transmission service for all other CEI South customers. Ms. Coyle observed that the settled rate is approximately 56% higher than the cost-based rate established at FERC. Ms. Coyle stated that as a result of this, the Settlement Agreement requires CEI South to evaluate transmission cost of service in the future. Ms. Coyle further refuted Mr. Barnes's testimony regarding Section 24 customers, noting that Mr. Barnes does not present the total picture of the change in cost allocation for customers when compared to CEI South's rebuttal position because he does not show the benefit to all customers from the Settlement for the reduction in the revenue requirement of approximately $35.4 million from CEI South's rebuttal position.

B. Phased Rate Implementation. As part of the Settlement Agreement, Section B.1 modifies the phases in which CEI South will implement its authorized increase to base rates and charges for electric utility service. The Settling Parties agreed that CEI South's proposed Phase 1 implementation shall be eliminated and CEI South should be authorized to increase its base rates and charges for electric utility service in two steps at a defined point in time as described in the Settlement Agreement. This stipulated term results in a savings to customers of approximately $13.25 million. While this stipulated term does not affect the revenue requirement, it helps mitigate the bill impact by lowering customer bills and represents additional value to customers on top of the agreed adjustments to the revenue requirement. Pet. Ex. 19-S at 8-9.

Section B.1.c provides that the Settling Parties agree CEI South should be authorized to implement interim rate increase steps after Posey Solar and the CT Project are placed in service as described by CEI South witness Behme.

i. <u>Pre-Test Year Phase and Process for Implementation of Phased Rates</u>.

1. <u>CEI South Case-in-Chief</u>. CEI South witness Behme testified that CEI South was proposing to implement rates in a minimum of three phases. As originally proposed, Phase 1 would be implemented upon issuance of an order in this Cause, based on the actual rate base and capital structure as of December 31, 2023. Revenues and O&M expense would be updated to November 2024, rather than the beginning of the test year. For Phase 2, CEI South proposed to reflect most of the pro forma test year results of operations, updated to reflect the actual rate base and capital structure as of December 31, 2024. CEI South proposed to implement rates as soon as possible following the beginning of the test year. For Phase 3, CEI South proposed to update to reflect the fully adjusted test year and the actual rate base and capital structure as of the end of the test year. Phase 3 would be implemented as soon as possible following the end of the test year. Pet. Ex. 2 at 6-7. Ms. Behme testified that this three-phase approach was modeled after the approach proposed by Indiana American Water Company in Cause No. 45870. She said pro forma results of operations at present and proposed rates would be based upon the test year data, but the operating expenses in Phase 1 would begin with November 2024 for the 12-month period and certain revenue and expense adjustments would not be included or would not be included at the full amount at Phase 1 because the changes for which these adjustments are made will not occur until the test year. Ms. Behme testified that, because all the information necessary to calculate Phase 1 rates would be available before the evidentiary hearing (other than the findings that are contained in the Commission's Final Order in this Cause) there should not be a need to build in a post-order review process for Phase 1 as there would be with later phases.

For Phase 2 rates, Ms. Behme stated they would be implemented as soon as possible after January 1, 2025 and based on actual net plant certified to have been completed and placed in service no later than December 31, 2024. She stated other parties to this proceeding should be provided up to 60 days to verify or state any objection to the net plant in service numbers from those which CEI South certifies, and a hearing should be convened, as necessary, to resolve any objections. She testified that Phase 2 rates should be subject to refund during the review period, and, if necessary, upon resolution of any objections, rates should be trued up, with carrying charges at the weighted average cost of capital, retroactive to the date Phase 2 rates were submitted. Ms. Behme explained that pro forma results of operations for purposes of Phase 2 rates should reflect the adjusted test year results of operations, modified as needed to reflect certain revenue and expense adjustments that will not have been fully reflected by the beginning of the test year.

For Phase 3, CEI South proposed the same process as for Phase 2, except using the end of test year rate base and capital structure.

2. **<u>OUCC's Position</u>.** OUCC witness Stull recommended denial of CEI South's initial proposed implementation of a rate increase prior to the start of its forward-looking test year. Pub. Ex. 6 at 18, 21. She said CEI South's proposal differs materially from the two proposals where the Commission allowed rates to be implemented prior to the start of a utility's forward-looking test year, Cause No. 45545 and Cause No. 45870. She said in both of those cases the utility did not seek to recover costs before they were projected to be incurred and their initial rate increase only reflected the effects of projected data through the date an order was expected to be issued. Ms. Stull contended that, even if the Commission felt it was appropriate to implement a pre-test year phase in the same manner as has previously been authorized, Petitioner did not provide any monthly data reflecting its projected pro forma operating net income for the linking period. Ms. Stull further opposed updating depreciation rates before the beginning of the test year (with Petitioner's Phase 1 rates).

OUCC witness Stull testified that Petitioner's authorized increase to total rate base should be limited to the forecasted amount. Pub. Ex. 6 at 23. She also recommended that, to the extent CEI South does not actually invest what it forecasted it would invest in rate base, adjustments to depreciation expense and property tax expense may be warranted, along with associated adjustments to income tax.

Ms. Stull recommended that, if the Commission finds it is appropriate to implement rates before the beginning of the forward-looking test year, a post-order review process should be implemented similar to the process to be implemented at the beginning and end of Petitioner's forward-looking test year. Among other things, Ms. Stull recommended that the Commission find that a technical conference may be convened at the request of any party or Commission staff to allow further discussion in determining whether the compliance filing complies with the order and determine what additional information should be provided in each phase. She listed what she recommended be included in Petitioner's compliance filings, including:

> 1. Certification of Petitioner's actual utility plant in service and actual capital structure.
> 2. Actual rate base by component, in a similar format to that of Exhibit No. 20, Schedule B-1.1 and comparing actuals to Petitioner's forecast. Any variances between actuals and the forecast greater than 10% should be explained.
> 3. Actual utility plant in service balances by FERC Account similar to Exhibit No. 20, Schedule B-2.1.
> 4. Actual accumulated depreciation balances by FERC Account similar to Exhibit No. 20, Schedule B-3.1.
> 5. Actual capital structure by component, in a format similar to that of Exhibit No. 20, Schedule D-1.1, including an updated calculation of weighted average cost of capital and comparing actuals to Petitioner's forecast. Any variance between actuals and forecast greater than 10% should be explained.
> 6. Calculation of Phase 1 rates based on the December 31, 2023 actuals as certified.

OUCC witness Eckert testified that CEI South's rates approved in this Cause should be implemented on a prospective basis applicable to service rendered after the rates become effective. Pub. Ex. 1 at 33.

3. <u>CEI South Rebuttal</u>. CEI South witness Behme disagreed with Ms. Stull's testimony that CEI South's proposal for Phase 1 rates differs from the pre-test year rates previously approved by the Commission. She said in both the Indiana American Water Company and the City of Evansville rate cases, the utilities' methods for calculating Phase 1 rates attempted to recover the revenue requirement being incurred at the anticipated date of order issuance. Pet. Ex. 2-R at 24. She said that, in both of those cases, the anticipated date of the Commission order was projected and that rates were proposed to be established upon issuance of the order that would recover the state of the projected revenue requirement as of that anticipated order date. Ms. Behme testified that, in both Cause No. 45870 and Cause No. 45545, the utility proposed to recover the level of costs beginning with the anticipated date of the order and not for the period leading up to the anticipated date of the order. Ms. Behme concluded that all three utilities have attempted to do precisely the same thing, which is to set Phase 1 rates at a level that will recover costs as they are being incurred during the period between the issuance of the Commission's order and the beginning of the test year.

Ms. Behme testified that, to the extent the OUCC's list of items required to be submitted and timing for review on pages 26-27 of Ms. Stull's testimony differs from the compliance filing requirements in Cause No. 45870, its request should be denied. Pet. Ex. 2-R at 28.

Witness Behme testified that CEI South would agree that forecasted additions to Utility Plant in Service ("UPIS") by the end of the test year should serve as a cap in calculating the actual rate base that is ultimately submitted as part of the compliance filing in any phase. However, the forecasted UPIS additions are only a cap for purposes of this proceeding (not a cap for purposes of a future general rate case or for purposes of capital trackers). Pet. Ex. 2-R at 28. She explained that, since the phase-in approach is required by the used and useful rule, any cap should be focused on the additions to used and useful plant that are forecasted to be placed in service before the end of the test year.

4. <u>Settlement</u>. CEI South witness Rice testified that Section B.3.a of the Settlement Agreement incorporated Ms. Stull's proposed cap on rate base for purposes of this case. Pet. Ex. 19-S at 9.

Mr. Rice stated that Section B.1 of the Settlement Agreement modifies the phases in which CEI South will implement its authorized increase to base rates and charges for electric utility service. The Settling Parties agreed that CEI South's proposed Phase 1 implementation shall be eliminated and CEI South should be authorized to increase its base rates and charges for electric utility service in two steps at a defined point in time as described in the Settlement Agreement. This stipulated term results in a savings to customers of approximately $13.25 million. While this stipulated term does not affect the revenue requirement, it helps mitigate the bill impact by lowering customer bills and represents additional value to customers on top of the agreed adjustments to the revenue requirement.

The first change in rates will be implemented pursuant to the process described below, which is essentially the same as that prescribed in Cause No. 45870, and will be based on the agreed revenue requirement as adjusted to reflect the actual capital structure and rate base as of December 31, 2024, subject to the Net Original Cost Rate Base Cap described in Section B.3.a of the Settlement Agreement ("Settlement Phase 1"), which incorporated Ms. Stull's proposed cap on rate base for purposes of this case. As noted in the Settlement Agreement, CEI South will submit a certification of its actual utility plant in service and actual capital structure as part of its compliance filing. The compliance filing will calculate rates for the applicable phase based upon these certifications, subject to the Net Original Cost Rate Base Cap as described in the Settlement Agreement. If necessary to resolve any objections, the Commission shall schedule a hearing. The Settlement Agreement further provides that within a week of CEI South's compliance filing, a technical conference may be held at the request of either a party or Commission staff to allow for further discussion in determining whether CEI South's filing complies with the order in this Cause and to determine what additional information, if any, should be provided for the Settlement Phase 2 compliance filing. Following issuance of a Final Order in this Cause approving the Settlement Agreement, Settlement Phase 1 rates will go into effect after the beginning of the test year and upon the effective date of the Commission's approval of the Settlement Phase 1 compliance filing (currently anticipated to be on or around March 1, 2025) for services rendered after that effective date, on an interim subject-to-refund basis pending a 60-day review using the process described above.

CEI South will implement the second defined change in rates pursuant to the process described above for Settlement Phase 1 and will be based on the agreed revenue requirement as adjusted to reflect the actual capital structure and rate base as of the end of the test year (December 31, 2025), subject to the Net Original Cost Rate Base Cap described in Section B.3.a of the Settlement Agreement ("Settlement Phase 2"). Pet. Ex. 19-S at 9-10. Settlement Phase 2 rates will go into effect upon the effective date of the Commission's approval of the Settlement Phase 2 compliance filing (currently anticipated to be on or around March 1, 2026) for services rendered after that effective date, on an interim-subject-to-refund basis pending a 60-day review using the process described above for Settlement Phase 1.

5. OUCC Settlement Opposition. OUCC witness Stull stated that, while she generally accepts the process the Settling Parties agreed to, CEI South should provide additional information so the Commission, the OUCC, and other parties to this case may conduct a meaningful review of the compliance filing to ensure compliance with the Commission's order. Pub. Ex. 6-S at 7. In addition to the information the Settling Parties agreed should be included, she recommended the following additional supporting information be submitted with CEI South's compliance filing:

1. Actual rate base by component as of December 31, 2024 (Phase 1) and December 31, 2025 (Phase 2), in a format similar to that of Exhibit No. 20, Schedule B-1.1 and comparing actuals to CEI South's applicable forecast. Any variances between actuals and the applicable forecast greater than 10% should be explained.
2. Actual utility plant in service balances by FERC Account as of December 31, 2024 (Phase 1) and December 31, 2025 (Phase 2) similar to Exhibit No. 20, Schedule B-2.1.
3. Actual accumulated depreciation balances by FERC Account as of December 31, 2024 (Phase 1) and December 31, 2025 (Phase 2) similar to Exhibit No. 20, Schedule B-3.1.
4. Actual capital structure by component as of December 31, 2023, in a format similar to that of Exhibit No. 20, Schedule D-1.1, including an updated calculation of weighted average cost of capital for each phase and comparing actuals to the applicable forecast. Any variance between actuals and the applicable forecast greater than 10% should be explained.

5. Calculation of rates based on actuals on December 31, 2024 (Phase 1) and December 31, 2025 (Phase 2) as certified.

Ms. Stull also requested that the Commission order that net operating income be adjusted to the extent projected investments are not made. Pub. Ex. 6-S at 10.

Mr. Eckert stated the Settlement Agreement does not recommend that any approved rate changes apply on a services rendered basis on or after the effective date of the rate change. Pub. Ex. 1-S at 14-15.

6. <u>Settlement Rebuttal</u>. In Attachment MAR-SR2 to Mr. Rice's Settlement Rebuttal testimony, he indicated that CEI South addressed Ms. Stull's request for additional information as part of the compliance filing on rebuttal (Pet. Ex. 2-R at 28). To the extent she is requesting information required in the order in Cause No. 45870, CEI South agrees. Mr. Rice stated this was the intent of the language of the Settlement Agreement and to the extent she is asking for more than the Cause No. 45870 order requires, her request should be denied. The Commission has already considered her requests for additional information beyond that which is required for other utilities (in Cause No. 45870) has set forth the information that reasonably is needed. He testified there is no reason to treat CEI South differently. Pet. Ex. 19-SR, Attachment MAR-SR2 at 2.

As for Ms. Stull's recommendation that net operating income be adjusted where projected investments are not made, Mr. Rice showed in his Attachment MAR-SR2 that the Settlement Agreement provides, at Section B.1.a (Phase 1) and B.1.b (Phase 2) that the revenue requirement will be adjusted at each phase to reflect actual capital structure and actual rate base, subject to the Net Original Cost Rate Base Cap.

With respect to Mr. Eckert's concern that rates be implemented on a "services rendered" basis, Attachment MAR-SR2 to Mr. Rice's Settlement Rebuttal refers to Sections B.1.a (Settlement Phase 1) and B.1.b (Settlement Phase 2) of the Settlement Agreement, both of which provide that rates will go into effect "for services rendered after the effective date." Pet. Ex. 19-SR, Attachment MAR-SR2 at 1.

ii. <u>Phased Rates – Interim Phases</u>.

1. <u>CEI South Case-in-Chief</u>. CEI South witness Behme described up to three additional interim steps Petitioner is proposing between Phases 2 and 3 (*i.e.*, the beginning and end of the test year) aligned with the placement in service of the CT Project and Posey Solar. She explained that, if the PISCC on these projects continue to accrue until the end of the test year, rate base and Phase 3 rates will be higher than if these projects were reflected in rates at an earlier time. As such, CEI South proposed to implement interim steps to reflect the additional after-tax return and depreciation expense on each of these projects (each CT, in the event there is a delay in implementation between the two, and Posey Solar) using the capital structure in effect at the beginning of the test year and used for Phase 2. Pet. Ex. 2 at 8-9. These interim steps would take effect upon filing of a certification in this Cause that the plant in question is in service. Ms. Behme clarified that, for Generally Accepted Accounting Principles ("GAAP") purposes, prioritization of recovery upon implementation of each interim step should mirror what presently occurs in various rider filings, with the first dollars recovered collecting the PISCC (both debt and equity) related to these investments. The same interim-subject-to-refund basis as for Phases 2 and 3 would apply, with the same time period for other parties to raise objections. Precisely how many interim steps there would be or when they would occur is not currently known, as they are dependent upon actual in-service dates of the plant in question. Accordingly, the overall revenue requirement shown in Petitioner's Exhibit No. 20 does not reflect these proposed interim steps.

2. <u>OUCC's Position</u>. Ms. Stull opposed CEI South's proposal to implement rate increases *during* the forward-looking test year. Pub. Ex. 6 at 28. She opined that this proposal unnecessarily complicates CEI South's rates, is unprecedented, undermines an already well-established process for updating rate base in forward-looking test year cases, increases regulatory costs and burdens, and would serve to confuse customers without any quantification of the benefit to ratepayers in avoiding less than 12 months of carrying costs.

3. <u>CEI South Rebuttal</u>. Ms. Behme and Mr. Rice both expressed surprise at Ms. Stull's opposition to the additional interim phased rate increases as the CT Project and Posey Solar are placed in service, citing the benefits to customers in avoiding the PISCC and deferred depreciation associated with those projects from the time they are in service until the time they are reflected in rates. Pet. Ex. 2-R at 28; Pet. Ex. 19-R at 58. Ms. Behme reiterated that the ultimate rates customers would pay at Phase 3 (end of test year) would be higher without these interim phases. Pet. Ex. 2-R at 28. Both Ms. Behme and Mr. Rice said that every month of delay would cause a rate base increase of $3.4 million for the CT Project and $3.7 million for Posey Solar. Pet. Ex. 2-R at 28; Pet. Ex. 19-R at 58. Mr. Rice testified that if these projects are placed in service in May 2025, CEI South would expect that it could file and place into effect the new rates by July 1, eight months before they would be reflected under Ms. Stull's proposal. Pet. Ex. 19-R at 58. He concluded that is almost $57 million of PISCC and deferred depreciation (*i.e.*, rate base) that could be avoided with additional interim steps.

4. <u>Settlement</u>. Section B.1.c of the Settlement Agreement stipulates implementation of interim rate increase steps after Posey Solar and the CT Project are placed in service. Based on projected in-service dates of May 2025 for Posey Solar and July 2025 for the CT Project, this results in a projected reduction to proposed rate base as contemplated in Section B.3.a.iii of the Settlement Agreement and discussed in Section 0.D (Rate Base) of this order. The Settlement Agreement provides that the actual reduction to rate base and the Net Original Cost Rate Base Cap will be based upon the actual reduction to forecasted PISCC and deferred depreciation based upon the actual in-service dates and actual rate implementation through interim steps. Settling Parties' Jt. Ex. 1 at Section B.1.c. Mr. Rice testified this reduction totals $25,100,595 for avoided PISCC and deferred depreciation related to the Posey Solar and CT Project. Pet. Ex. 19-S at 11.

iii. <u>Commission Discussion and Findings</u>. The Settlement Agreement eliminated the controversy over Petitioner's proposed pre-test year rate implementation. Accordingly, we find the proposed Settlement Phase 1 (beginning of test year) and Settlement Phase 2 (end of test year) rate implementation to be a reasonable resolution of the dispute between the parties and therefore in the public interest.

CEI South witness Behme indicated Petitioner's acceptance of the requirements imposed for similar phased rate filings in our recent order in Cause No. 45870. This included the availability of a technical conference as needed for Petitioner to explain its compliance filing. We find this, along with the Settlement Agreement's provision for review and objection, as well as the potential for a hearing on any such objection, provides ample opportunity for the parties and Commission staff to conduct a thorough review of the compliance filing and resolve any questions. CEI South has accepted the same compliance filing requirements as set forth in Cause No. 45870, and we find those parameters sufficient to address the concerns raised by the OUCC.

With respect to CEI South's proposed interim rate implementations after Posey Solar and the CT Project are placed in service, the evidence demonstrates these additional steps will benefit customers through a reduction to rate base for avoided PISCC and deferred depreciation. We therefore find this term of the Settlement Agreement to be in the public interest.

Petitioner's Settlement Phase 1 and Settlement Phase 2 rates shall be implemented using the process described in Sections B.1.a and B.1.b of the Settlement Agreement. Petitioner's proposed interim rate increases to reflect Posey Solar and the CT Project shall be implemented as described in CEI South witness Behme's direct testimony, using the same process and compliance filing requirements as for Settlement Phase 1 and Settlement Phase 2 rates.

C. Overall Revenue Requirement and Authorized Net Operating Income. Section B.2 of the Settlement Agreement addresses the stipulated revenue requirement, revenue increase and authorized NOI.

CEI South witness Rice stated that, for Section B.2 of the Settlement Agreement, the Settling Parties have agreed to a total revenue requirement of $803,932,466, which requires a net increase in revenues at present rates of $80,009,617. Pet. Ex. 19-S at 10. He explained the increase in revenues is net of the reduction to revenues resulting from the stipulated reduction to the base cost of fuel based on the OUCC's recommendations, as well as the stipulated reduction to purchased power expense due to the reduction in purchased capacity cost set forth in the Settlement Agreement. CEI South originally requested a revenue increase of $118,757,693, modified to $115,445,697 on rebuttal. The stipulated agreement is a decrease of $35,436,080 from CEI South's request at rebuttal. The Settlement Agreement results in a proposed authorized NOI of $187,518,958.

CEIS Industrial Group witness Gorman opined that the revenue terms of the settlement are reasonable. IG Ex. 4 at 3. He explained in his direct testimony he recommended that the revenue increase be no more than $89.2 million. Even so, the Settling Parties were able to reach agreement on an increase of only $80.0 million. He stated the range of potential litigation outcomes was between CEI South's rebuttal position of $115.4 million and the OUCC's proposed $48.3 million increase. The settled increase falls below the $81.9 million midpoint of that range. In his opinion, the settled revenue requirement is a reasonable resolution of the revenue issues raised in this case, is fully supported by the record as a whole, and represents a fair compromise on the revenue disputes raised in the litigated phase of this proceeding.

The disputed components of Petitioner's revenue requirement, and the stipulated resolution of those issues within the Settlement Agreement, are discussed in greater detail in each of the subsections below. The Commission's ultimate finding on Petitioner's authorized revenue increase and NOI can be found in Paragraph 9 (Overall Authorized Increase) below.

D. **<u>Rate Base</u>.** Sections B.3(a) and (b) of the Settlement Agreement set forth the Settling Parties' stipulations regarding original cost rate base and other rate base items, respectively.

Specifically, the Settling Parties stipulated that the original cost rate base on which Petitioner should be authorized to earn a return for Settlement Phase 1 shall be the actual net original cost rate base as of December 31, 2024 and for Settlement Phase 2 shall be the actual net original cost rate base as of December 31, 2025. The Settling Parties further stipulated that the net original cost rate base at either Settlement Phase 1 or Settlement Phase 2 shall not exceed the forecasted end-of-test-year net original cost rate base of $2,769,851,666, as adjusted for the actual reduction to forecasted PISCC and deferred depreciation based upon the actual in-service dates and actual rate implementation through interim steps for the CT Project and Posey Solar (the "Net Original Cost Rate Base Cap").

The stipulation as to net original cost rate base includes the following stipulated modifications to CEI South's forecasted rate base presented on rebuttal: (1) the reduction to coal inventory of an additional $2,949,966 as proposed by OUCC witness Eckert; (2) the removal of $212,036 in additional net investment in the ULRC, as recommended by OUCC witness Armstrong; and (3) the reduction for avoided PISCC and deferred depreciation in conjunction with the stipulations in the Settlement Agreement regarding interim phases of rates.

In addition, CEI South stipulated and confirmed: (1) that amounts reflected in Table B.3.b.i of the Settlement Agreement related to land acquisition and identified in OUCC witness Armstrong's testimony are not included in the forecasted rate base for purposes of Settlement Phase 1 or Settlement Phase 2 rates, and (2) that the amounts related to the Culley Unit 3 Natural Gas conversion and identified in OUCC witness Krieger's testimony and CEI South witness Bradford's rebuttal testimony will not be included in rate base in this Cause, but instead will be addressed as part of Petitioner's later anticipated proposed certificate of public convenience and necessity ("CPCN") proceeding related to said conversion. Settling Parties' Jt. Ex. 1 at Sections B.3(a) and (b).

Below is a summary of CEI South's case-in-chief evidence in support of its rate base, the contested issues resolved through Petitioner's rebuttal and/or the Settlement Agreement, and the remaining items in dispute.

Ms. Behme testified that the "Adjustments" column on Schedule B-2 and B-2.1 of Petitioner's Exhibit 20 reflects three primary adjustments to gross plant in service and accumulated reserve forecasted as of December 31, 2025. Pet. Ex. 2 at 14. First, she said an adjustment was made to remove utility plant in service and associated accumulated depreciation of MISO Regional Expansion Criteria and Benefit ("RECB") transmission plant in service. She said that, under the Commission's Order in Cause No. 43111, CEI South has treated MISO-approved RECB investments as FERC jurisdictional. The second adjustment is to remove utility plant in service and associated accumulated depreciation of the assets associated with Troy Solar. Ms. Behme explained that CEI South was granted authority to recover the costs of Troy Solar using a levelized rate through the CECA annual tracker. As part of the settlement agreement in Cause No. 45086, the order states that the project will be excluded from the calculation of CEI South's electric revenue requirement in each rate case over the life of the project. Specifically, as it pertains to this adjustment, the order states that the project will be excluded from rate base in such future base rate cases. The third adjustment removes utility plant in service and associated accumulated depreciation of the assets associated with Crosstrack Solar. CEI South was granted authority to recover the costs of Crosstrack Solar using a levelized rate through the CECA annual tracker. The unadjusted forecast assumes that Crosstrack Solar would be placed in service during the test year as was detailed in Cause No. 45754. Like the way CEI South accounts for Troy Solar, per the Final Order in Cause No. 45754, when completed CEI South would have excluded Crosstrack Solar from rate base in future base rate cases. In addition, Ms. Behme noted that the commercial operation date for Crosstrack Solar has been updated to 2026, which is beyond the test year in this Cause. As a result, none of the costs associated with Crosstrack Solar should be included in this case.

Ms. Behme described the 11 specific items included in rate base as other rate base components (Schedule B-4): (1) fuel stock; (2) utility materials and supplies; (3) storeroom expenses associated with materials and supplies; (4) allowance inventory; (5) regulatory asset associated with deferral of PISCC related to CEI South's AMI project (approved in Cause No. 44910); (6) regulatory asset associated with deferral of PISCC related to CEI South's initial TDSIC plan (approved in Cause No. 44910); (7) regulatory asset associated with deferral of PISCC related to CEI South's second TDSIC plan (approved in Cause No. 45894); (8) regulatory asset associated with deferral of PISCC related to CEI South's annual CECA proceeding (approved in Cause No. 44909, with amounts approved in subsequent CECA proceedings); (9) regulatory asset associated with deferral of PISCC related to CEI South's annual ECA proceedings (approved in Cause No. 45052, with amounts approved in subsequent ECA proceedings); (10) regulatory asset associated with deferral of PISCC related to the F.B. Culley East Ash Pond Closure (approved in Cause No. 45903); (11) regulatory asset associated with deferral of PISCC related to the natural gas combustion turbines ("CTs") (approved in Cause No. 45564). The first four components are reflected using 13-month averages of the actual balances for the monthly periods ended December 31, 2022 except that fuel stock and utility materials and supplies were adjusted to reflect the retirement of A.B. Brown and Warrick Unit 4. Pet. Ex. 2 at 17-18.

CEI South witness Bradford provided an overview of CEI South's Generation Portfolio and its Generation Transition Plan. Of the new resources being added to CEI South's Generation Portfolio, he indicated the CT Project and Posey Solar are included in the forecasted rate base in this case. He provided an update on the CT Project and the Posey Solar. Pet. Ex. 7 at 13-14. He also described how CEI South has managed capacity needs until the replacement generation is placed in service in 2025. Attachment FSB-1 to Mr. Bradford's direct testimony is a summary of capital investments made at CEI South generating stations since the rate base cutoff date in CEI South's last base rate case, Cause No. 43839, with projects greater than $5 million individually identified. It excludes Troy Solar, Crosstrack Solar, and those investments that have since been retired with the securitization of A.B. Brown Units 1 & 2.

In rebuttal, Ms. Behme described in rebuttal an adjustment to the ECA PISCC balances in Petitioner's Exhibit No. 20-R to reflect a correction identified after the OUCC and intervenors had filed their cases-in-chief. Pet. Ex. 2-R at 4. She said CEI South reduced the PISCC balances for the ECA mechanism by $20,783,641. Ms. Behme explained that it was discovered that there were balances in the forecast for these accounts that are attributed to the Mercury and Air Toxics Standards ("MATS") Program in the ECA mechanism. The PISCC balances associated with MATS were removed from the general ledger in 2023 and included in CEI South's Securitization filing in Cause No. 45722. Since these balances were removed from the general ledger, CEI South has removed these balances from Petitioner's Exhibit No. 20-R in this proceeding, resulting in a reduction to the revenue requirement of $2,729,234.

i. Rate Base Items Resolved through Rebuttal.

1. Culley East Ash Pond. OUCC witness Armstrong testified that the Commission had denied CEI South's recovery of the Cause No. 45795 legal costs in Cause No. 45903. Pub. Ex. 7 at 12. Accordingly, she recommended an increase to accumulated depreciation to remove the disallowed legal costs for the Culley East Ash Pond project and an associated reduction to test year amortization expense.

Ms. Behme testified on rebuttal that, to comply with the Final Order received February 7, 2024 in Cause No. 45903, CEI South removed certain disallowed legal fees from the rate base reflected in Petitioner's Exhibit No. 20-R. Pet. Ex. 2-R at 5. She stated CEI South has also made the necessary adjustments to ECA revenues, accumulated depreciation, and amortization expense associated with this reduction.

2. Emissions Allowance Inventory. OUCC witnesses Lantrip and Armstrong recommended the Commission deny the Emissions Allowance portion of costs in base rates, contending that Petitioner has not demonstrated prudence regarding the management of its allowance inventory. Mr. Lantrip recommended embedding a zero balance in base rates and Petitioner's approval of its Emissions Allowance inventory variance be contingent upon an improvement of its practices, as demonstrated through updates of less volatility in inventory levels presented in its RCRA Rider testimony. Pub. Ex. 3 at 13-14. Ms. Armstrong testified that the 2022 historical period CEI South used to forecast allowance inventory is not representative of what its operations are likely to be going forward due to unusual events in 2022 that she stated inflated the monthly allowance inventory balances. Pub. Ex. 7 at 3. She said that, because CEI South will be retiring all but one of its coal units by 2026, its need to purchase emission allowances will decrease in future years. She also stated that CEI South's filed exhibits and workpapers did not provide detailed monthly emission allowance inventory calculations by allowance type, which she said was necessary to verify the monthly allowance inventory balance and expense. She testified that, to reflect the changes in the NOx Seasonal market and the benefits of CEI South's Generation Transition Plan, it is reasonable to value test year allowance inventory at zero. This recommendation would remove $1,282,707 of rate base and $3,519,952 of Emission Allowance O&M costs from the test year. Pub. Ex. 3 at 14; Pub. Ex. 7 at 10.

On rebuttal, Ms. Behme indicated CEI South's acceptance of the OUCC's proposal, resulting in the removal of $1,282,707 from rate base. Witness Behme testified that while CEI South believes there would be a balance of emission allowance inventory represented on the balance sheet in the test year, she acknowledged that the actual historical balances used for the basis in this case are not representative of what the balance will be for the test year, and Petitioner agrees to remove the balance entirely. Pet. Ex. 2-R at 5.

ii. Rate Base Items Resolved in Settlement.

1. Coal Inventory. OUCC witness Eckert disagreed with CEI South's proposed coal inventory level. Pub. Ex. 1 at 34. He testified that CEI South had excessive coal inventory during most of 2023, imposing an additional and unnecessary cost on ratepayers. He calculated a recommended coal inventory level of $8,990,701, a reduction of $2,949,966 from CEI South's proposed amount of $11,940,667.

CEI South witness Bradford testified on rebuttal that Mr. Eckert's simplistic calculation of a recommended coal inventory level was incomplete and used debatable assumptions. Pet. Ex. 7-R at 10-11. He explained that as shown in Schedule B-4 of Petitioner's Ex. No. 20, the fuel stock rate base component has additional constituents besides the Culley coal inventory, such as the natural gas underground storage inventory, the Brown Unit 3 gas turbine fuel oil inventory, and the fuel coal inventory – which totals approximately $775,000. Mr. Bradford also disagreed with Mr. Eckert's assumptions regarding the Culley coal pile inventory, including the optimal number of days' supply. He said the reduced fleet coal inventory warrants a higher optimal number of days. He also stated Mr. Eckert did not account for the Culley Unit 2 maximum daily coal burn. He also disagreed with Mr. Eckert's use of a single point of reference versus a time-based average coal pile inventory cost.

In his settlement testimony, Mr. Rice stated that the Settlement Agreement reduces coal inventory by an additional $2,949,966 as proposed by Mr. Eckert. Pet. Ex. 19-S at 10.

2. Urban Living Research Center. CEI South witness Bradford gave an overview of the ULRC Project which was approved in Cause No. 44909. He explained that the Commission originally approved an estimated investment of approximately $2 million to be recovered through the CECA mechanism. Pet. Ex. 7 at 19. In Cause No. 44909 CECA 2 ("CECA 2"), the Commission approved a change in scope and corresponding decrease to the project cost estimate to $1.5 million. Pet. Ex. 7 at 19-20. In Cause No. 44909 CECA 4 ("CECA 4"), CEI South provided updates to the ULRC design, as well as updates to the estimated final project cost of $1.15 million. Mr. Bradford testified that CEI South did not request approval of, nor did the Commission approve, any revisions to the cost estimate in CECA 4 from the $1.5 million approved in CECA 2. In Cause No. 44909 CECA 5 ("CECA 5"), the Commission approved recovery of $1,150,000 out of the final project cost of $1,465,288, finding that although the final project cost was within the $1.5 million approved in CECA 2, CEI South had not established that the remaining costs were reasonable or appropriate for a project with significantly less capacity than was projected in CECA 2. CEI South sought to recover the remaining unrecovered balance of the ULRC project in this case, which is $219,348. Mr. Bradford explained that, with the ULRC being a pilot project, CEI South ran into unforeseen challenges beyond its control to get the project to fruition in 2022. He described those challenges in detail and said the cost increases were beyond CEI South's control and were necessary costs for the completion of the ULRC project. To address the Commission's finding that CEI South failed to establish the additional costs were reasonable or appropriate, he provided a detailed breakdown of the additional $219,348.

OUCC witnesses Lantrip and Armstrong recommended Petitioner's request to include $219,348 of net project costs related to the ULRC be denied. Pub. Ex. 3 at 4; Pub. Ex. 7 at 28. Mr. Lantrip said the Commission's most recent Order in CECA 5 found ratemaking recovery should be limited to the $1.15 million project estimate given in CECA 4, due to the project's changes in scope from the previous approved cost in CECA 2. He stated CECA 5 also required Petitioner to update the Commission on the outcome of Petitioner's U.S. Department of Energy reimbursement request for $60,000. Pub. Ex. 3 at 4. Ms. Armstrong testified that the detailed breakdown and associated justification of the additional ULRC costs in his direct testimony in this Cause is information that the Commission already had when it made its decision in CECA 5 to disallow the additional costs. Pub. Ex. 7 at 15. Ms. Armstrong noted that CEI South did not file a petition for reconsideration in CECA 5. She also asserted that CEI South made the decision to request that the ULRC be exempt from the requirements of Ind. Code ch. 8-1-8.5, and it should not be entitled to benefits similar to the guaranteed rate recovery under Ind. Code § 8-1-8.5-6.5 afforded to projects that have provided enough evidence to persuade the Commission to issue a CPCN under Ind. Code § 8-1-8.5-5(b) and (d).

On rebuttal, CEI South witness Bradford disagreed with OUCC witness Lantrip that the Commission's CECA 5 Order "found ratemaking recovery [for the ULRC project] should be limited to $1.15 million." He explained that he did not interpret the CECA-5 order as prohibiting CEI South from seeking to include that amount in rate base in this proceeding or foreclosing the request included in this case. Pet. Ex. 7-R at 13.

Mr. Rice testified that the Settlement Agreement removed a net amount of $212,036 in additional investment in the ULRC as recommended by OUCC witness Armstrong. Pet. Ex. 19-S at 10.

3. <u>PISCC and Deferred Depreciation Avoided for Interim Phases</u>. By virtue of the stipulations included in the Settlement Agreement related to interim phases of rates implementation, discussed in Paragraph 0.B (Phased Rate Implementation) of this order, reductions to rate base totaling $25,100,595 will be realized due to the avoided PISCC and deferred depreciation for the CT Project and Posey Solar. Pet. Ex. 19-S at 11; Settling Parties' Jt. Ex. 1 at Section B.3.a.

4. <u>Land Acquisitions</u>. OUCC witness Armstrong recommended the removal of amounts from rate base related to the acquisition of five properties bordering the A.B. Brown Generating Station. Pub. Ex. 7 at 21. She testified that, in response to discovery, CEI South stated that the land was purchased as buffer property and that these properties may be impacted from a nuisance perspective by activities related to completing closure of the ash pond. Ms. Armstrong contended that CEI South did not adequately justify the need for these land purchases and they are not currently used and useful for the provision of electric service. She said that although purchasing these properties likely reduced CEI South's future litigation risk, allowing CEI South to recover these costs shifts the risk of CEI South's management decisions and business operations from its shareholders onto its customers. She testified that if CEI South invests in future improvements to the property that are found to be reasonable and prudent for providing electric service to customers, then it may be appropriate seek recovery of the land as part of its request to recover these investments. However, she said it is premature for CEI South to recover these land purchases now and recommended removal of the costs of these acquisitions, reducing Petitioner's rate base.

While CEI South witness Bradford initially offered rebuttal objecting to the OUCC's proposed exclusion of the land acquisition costs in rate base, Petitioner's response to the Commission's April 29, 2024 docket entry questions made clear that the acquisition costs were not actually included in rate base in the revenue requirement. Pet. Ex. 23.

Section B.3.b of the Settlement Agreement stipulates and confirms that $2,143,866 related to a land acquisition and identified in OUCC witness Armstrong's testimony is not included in the forecasted rate base in this Cause and will not be reflected in the actual rate base for purposes of Settlement Phase 1 or Settlement Phase 2 rates. Settling Parties' Jt. Ex. 1; Pet. Ex. 19-S at 11.

iii. Remaining Disputed Rate Base Items.

1. Steam Production Plant, Coal Silo, and Culley Expenses. OUCC witness Krieger recommended a $150.7 million reduction of capital investment in Steam Production Plant CEI South included in rate base, resulting in a reduction to the revenue requirements of $9.2 million. Pub. Ex. 9 at 2 and 15. This reduces annual depreciation by an estimated $8.6 million and reduces the annual revenue requirement by an additional $9.2 million. He identified certain utility plant investments as concerning. He reviewed Mr. Bradford's attachments and workpapers showing all capital investment at Steam Production Plan following the rate base cutoff in Petitioner's last general rates case. He said certain investments in replacement and refurbishments should have been expensed as maintenance instead of capitalized and he has concerns about CEI South's project management and accounting discipline. He said the $104.7 million he sought to remove from rate base reference repairs, replacements and refurbishments, and other categories that are maintenance, not investment. He said these items keep an asset running but do not extend the asset's useful life.

Mr. Krieger also took issue with the inclusion of amounts for modifications to a coal silo that later failed. Mr. Krieger does not believe this amount should be added to rate base or borne by consumers because the cost is a result of poor project management. Pub. Ex. 9 at 13. He recommended removal of $8,821,876 from rate base related to the 2016 Culley Unit 3B Coal Silo Failure.

OUCC witness Eckert recommended that, if the Commission finds CEI South was at fault for the Culley Unit 3 outage, the Commission should reduce rate base by $7,139,191 to remove the capital cost to repair Culley Unit 3. Pub. Ex. 1 at 39. IG witness Gorman recommended that, to the extent the Commission ultimately finds imprudence caused the outage at issue in Cause No. 38708 FAC 137 S1, then the full revenue requirement impact of the test year for all imprudent capital costs associated with the Culley outage should be removed from CEI South's cost of service. IG Ex. 1 at 136-137.

Mr. Krieger also argued that the Commission should disallow amounts included in rate base for FB Culley 3 major projects. He contended that these amounts should not be included in rates until a future CPCN for FB Culley Unit 3's conversion to natural gas is approved by the Commission. Pub. Ex. 9 at 14.

CEI South witness Cunningham responded to Mr. Krieger's proposed removal of $104.7 million in utility plant in service based on his position that those items were inappropriately capitalized. He said Mr. Krieger has paraphrased CEI South's capitalization policy and taken it out of context. He also said Mr. Krieger's proposed capitalization test is inconsistent with the FERC Uniform System of Accounts ("USOA"). Pet. Ex. 22-R at 3. Mr. Cunningham stated the FERC USOA sets forth the rules for capitalization when individual items of property that are part of a larger asset are replaced and that Mr. Krieger's proposed test that the replacement should increase the entire useful life or salvage value of an asset is not part of the analysis. He said CEI South has a written listing or catalogue as alluded to by Mr. Krieger but the OUCC did not ask for that catalogue to be produced in discovery. A copy of the catalogue was attached as Petitioner's Exhibit No. 22-R, Attachment JAC-R1. He said that if a retirement unit is replaced, it is to be capitalized. If a component part of a retirement unit is to be replaced, it is expensed. And, as the USOA makes clear, "consistency" in application is key. Mr. Cunningham testified that the items identified by Mr. Krieger, including pumps, valves, and process piping are considered discrete retirement units, or assets, for CEI South. These retirement units were established almost 20 years ago and replacements of these retirement units have been consistently capitalized by CEI South in the normal course of operations. Mr. Cunningham said replacements of retirement units result in the prior asset being retired and the new asset being added to the plant-in-service records. The newly installed asset does represent additional investment with a new useful life. Mr. Cunningham testified that CEI South has an internal controls team that reviews and confirms CEI South is appropriately capitalizing assets and its financial statements are audited by independent certified public accountants for compliance with GAAP. Finally, the regulatory financial statements that are reported to FERC are also audited by the same firm of certified public accountants. He stated CEI South undergoes considerable diligence to assure that the capitalization decisions are correct and in compliance with the FERC USOA. Mr. Cunningham also explained that Instruction 10 of the USOA dictates Mr. Krieger is incorrect. When a retirement unit is removed from service, the utility is to credit Utility Plant in Service and debit Accumulated Depreciation for the original cost of the unit, regardless of how many years the unit has been in service. In this fashion, the retirement of a retirement unit has zero effect on net original cost rate base (except for salvage and cost of removal). Consequently, the entries that are booked to retire a retirement unit do not imply that the unit was fully depreciated.

Mr. Bradford explained in rebuttal that, when the Culley Unit 3B Coal Silo failed in July 2016, an outside engineering firm performed a root cause analysis ("RCA"). He noted that the engineering firm determined the root cause to be the liner modification not being installed in 1978, by the contractor as specified in the 1976 design document thereby causing the coal silo skirt-to-cone weld to fail from approximately 40 years of corrosion. He added that the third-party RCA is provided as Petitioner's Exhibit No. 7-R, Attachment FSB-R2. Pet. Ex. 7-R at 5. Mr. Bradford described the amounts covered by the insurance carrier and amounts included in rate base in this case. He said the amount associated with the Culley Unit 3B Coal Silo Failure nets to $4,600,428, reducing Mr. Krieger's recommendation by more than $4 million. *Id.* He pointed to the RCA and the insurance carrier to argue that there is no evidence of poor project management. Specifically, the RCA states “[a] likely scenario that would allow this to occur is that the 204 SS liner installation detail was modified in the field without knowledge of Vectren Power Supply.”

Mr. Bradford provided a breakdown of the $41.4 million of rate base Mr. Krieger sought to disallow with respect to certain capital investment projects related to Culley, explaining they relate to turbine overhaul and rotor replacement, boiler components and air heater baskets replacements, environmental emission monitoring equipment replacement, coal-pulverizer piping replacement, expansion joint replacement, station battery replacement, and cyber security monitor equipment for the control system, as well as including approximately $7.8 million for the Culley Unit 3 Outage capital expenditures. Mr. Bradford agreed that the Culley Unit 3 conversion should not be included in rates until the Commission has approved a CPCN or an alternative recovery method such as a new tracker. He explained that his Workpaper FSB-1 (Confidential) set forth the capital spend during a period of time but not necessarily amounts included in rate base in this case. Pet. Ex. 7-R at 9.

Mr. Bradford did not agree with the proposed disallowance of the other Culley capital projects. With respect to the turbine overhaul, he testified that the original equipment manufacturer (“OEM”) – General Electric – recommends a turbine overhaul, such as Culley Unit 3, every seven to ten years. He noted that the last turbine overhaul performed on Culley Unit 3 was in 2014, putting the next scheduled overhaul at 11 years. CEI South has already delayed the overhaul until 2025 due to the previous Culley Unit 3 Forced Outage from June 2022 – March 2023; therefore, Mr. Bradford stated it would not be prudent to push the turbine overhaul beyond 2025 given OEM guidance. With respect to the remainder of the projects, Mr. Bradford testified that they will continue to be used after the gas conversion project, but these projects are prudent and will be needed even if a CPCN is not issued for the gas conversion project. He said the turbine and boiler remain essential if the gas conversion occurs, and, if the Commission does not approve the Culley Unit 3 conversion, one cannot assume that Unit 3 will no longer be used and useful. Mr. Bradford stated if the Commission denies the natural gas conversion, it is more than likely the unit would continue to operate until the next IRP cycle provides further guidance on a suitable replacement or until environmental requirements require closure.

With respect to the OUCC and IG recommendations that the Commission remove from rate base costs associated with returning Culley Unit 3 to service following the forced outage in the event the Commission should find CE South was imprudent in Cause No. 38708 FAC 137 S1, Mr. Bradford indicated CEI South opposed the OUCC’s and IG’s recommended findings of imprudence and disallowance in that subdocket. That said, to the extent the Commission’s Final order differs from that proposed by CEI South in either Cause, Mr. Bradford stated CEI South will update its schedules to comply. Pet. Ex. 7-R at 3.

In his settlement testimony, Mr. Rice described Section B.3 of the Settlement Agreement, which addresses, among other things the original cost rate base. He said the Settlement Agreement reflects CEI South’s test year end net original cost rate base on which it should be permitted to earn a return at $2,769,851,666, which will be adjusted for the actual reduction to forecasted PISCC and deferred depreciation based upon the actual in-service dates and actual rate implementation through interim steps for the CT Project and Posey Solar. He noted that this includes CEI South’s original proposal less a reduction to rate base of $50,617,095:

(1) to reduce coal inventory for an additional $2,949,966 as proposed by OUCC witness Michael Eckert;

(2) to remove a net amount of $212,036 in additional investment in the ULRC as recommended by OUCC witness Cynthia Armstrong;

(3) for a reduction totaling $25,100,595 for avoided PISCC and deferred depreciation in conjunction with the stipulations set forth in Section B.1.c of the Settlement Agreement related to Posey Solar and CT Project;

(4) for a reduction of $20,783,641 for PISCC associated with ECA projects as described on pages 4-5 of the rebuttal testimony of CEI South witness Behme;

(5) for a reduction of a confidential amount for Culley East ash pond legal fees, as accepted by CEI South on rebuttal and further described in Ms. Behme's testimony and

(6) to reduce rate base NOx allowance inventory by $1,282,707 as accepted by CEI South on rebuttal and further described on page 5 of Ms. Behme's rebuttal.

Section B.3.b of the Settlement Agreement also stipulates and confirms that $2,143,866 related to a land acquisition and identified in the pre-filed testimony of OUCC witness Armstrong is not included in the forecasted rate base in this Cause and will not be reflected in the actual rate base for purposes of Settlement Phase 1 or Settlement Phase 2 rates. Section B.3.b also stipulates and confirms that amounts related to F.B. Culley Unit 3 natural gas conversion identified by OUCC witness Krieger will not be included in this Cause.

OUCC witness Krieger opposed the Settlement Agreement because it did not address his allegations that CEI South had capitalized maintenance. He reiterated his position that CEI South's request for certain capital investment to be included in rate base remains unreasonable. Pub. Ex. 9-S at 2. He recommended a $150.9 million[13] reduction of capital investment in Steam Production Plant that CEI South proposed to include in rate base. Mr. Krieger also recommended a complete audit review to ensure Petitioner's capitalization of maintenance was not more prevalent than Petitioner presented, as well as ongoing audits and a refund of excess earnings garnered by CEI South through this practice. He stated that the impact of this recommendation would also reduce annual depreciation and the annual revenue requirement. He then said that information provided in CEI South's response to the Commission's docket entry dated April 29, 2024, CEI South confirmed that it had capitalized component items of multiple retirement units over a period of 11 years. He said this merits Commission scrutiny and future audits following a Final Order in this Cause. He said CEI South did not properly implement its policies and procedures. He called capitalizing valve replacements an "egregious violation" of the utility's policy when it occurs for 11 years. He further asserted that CEI South has shown a "longstanding disregard for proper treatment of rate base by capitalizing expense items." He said another example of Petitioner's deficient capitalization procedures is its failure to issue a Property Unit Catalog for solar

[13] Mr. Krieger recommended $150.9 million in Settlement opposition testimony (Pub. Ex. 9-S at 2), but did not explain the discrepancy between this number and the $150.7 million recommended disallowance in his direct testimony. Pub. Ex. 9 at 9.

generation assets, although CEI South has owned and operated solar generating facilities since 2018. Mr. Krieger requested the Commission order two types of audits: first, a complete historical audit, at CEI South's expense, and second, routine audits that last until CEI South's next rate case and are performed by a reputable accounting firm to ensure this practice is discontinued. Mr. Krieger recommended the cost of these audits should also be borne by CEI South and its shareholders.

Mr. Krieger reiterated his recommendations to exclude from rate base amounts for F.B. Culley 3 major projects and natural gas conversion as described in his direct testimony and amounts related to the replacement of a coal silo failure as described in his direct testimony. Pub. Ex. 9-S at 7.

On Settlement rebuttal, Mr. Rice noted that it appeared Mr. Krieger had adjusted his proposed disallowance related to the silo failure to $4.6 million from $8.8 million. He also testified that the $7.8 million to restore Culley Unit 3 following its forced outage should also no longer be in dispute given that the Commission found in Cause No. 38708 FAC 137 S1 that CEI South was not imprudent. In addition, Mr. Bradford had clarified on rebuttal that a significant portion of the Culley expenditures Mr. Krieger proposed to disallow were not included in rate base in this Cause. Pet. Ex. 19-SR at 17. Mr. Rice objected to Mr. Krieger's claims that CEI South had improperly capitalized component items of multiple retirement units over a period of 11 years. He stated CEI South has already conducted an audit of every expenditure since the last rate case making up Mr. Krieger's proposed disallowance. As indicated in CEI South's response to the Commission's docket entry dated April 29, 2024, CEI South identified 21 individual listings that would be in the test year and rate base in this case that may be component parts of retirement units. This was 21 out of a total of 12,161 lines of expenditures representing 1,139 individual projects placed in service over more than a decade. He said that, out of the $104.7 million in expenditures, CEI South identified $2.3 million, or 2.2%, for which CEI South does not have an explanation for why the expenditures were capitalized. He explained that CEI South did not "admit" that these amounts were improperly capitalized but stated it cannot identify why they were capitalized. Mr. Rice said that was an unfortunate circumstance that has arisen due to the passage of time as personnel who would have made the decisions over the years are no longer with CEI South. He testified that Mr. Krieger's suggestion to disallow $150.9 million has been refuted by the audit, Mr. Cunningham's and Mr. Bradford's rebuttal, and the Commission's Order in the FAC Subdocket. Further, Mr. Rice stated, his claim that this is an "egregious violation" warranting a presumption that CEI South does not properly keep its books is completely unjustified.

2. <u>IT-Related Investments</u>. CEI South witness Bahr presented testimony describing CEI South's cost optimization and resiliency strategies. He described the major IT investments that have been, or are in the process of being, implemented, namely: investments consistent with Cost Optimization, including Enterprise Integration Program ("EIP"), AMI, Advanced Distribution Management System ("ADMS"), Supervisory Control and Data Acquisition ("SCADA"), Digital Delivery, Cloud Acceleration, Transformation, and Optimization ("CATO"), and the SAP Business, Planning, and Consolidations ("BPC") Program; and investments consistent with Resiliency, including Cybersecurity, Network Transformation, and Data Center Refresh and Resiliency. Pet. Ex. No. 8 at 8 through 27.

OUCC witness Compton opposed CEI South's proposed inclusion of IT investments in rate base, stating CEI South had not substantiated its proposed IT investments in its case-in-chief or provided sufficient evidence demonstrating the necessity of all the investments. Pub. Ex. 5 at 4. He stated there are no studies, reports, and projections supporting or identifying how CEI South's IT investments will benefit the resiliency and security of its systems, the difference in efficiency between the old and new applications, or how much application maintenance and support costs might decrease. Mr. Compton argued that the benefits Mr. Bahr claimed are merely broad assertions without support. He testified that, while CEI South did claim two of its applications have reached or will reach obsolescence, it did not explain, support, or show that its other technologies have reached that stage in their lives. He testified that CEI South simply stated its new investments will increase the efficiency of its operations without any cost-benefit study analyzing the level of improvements compared to investment cost. He contended that, with the evidence provided, there is no way to determine whether the investments CEI South has made and plans to make for its IT development are prudent or reasonable. Mr. Compton commented that it seemed incongruous for CEI South to claim it will realize decreased maintenance costs, increased resiliency, and improved efficiency but will still require the same FTE support staff as it did prior to the proposed IT investments. He derived a pro rata allocation methodology he used to allocate his recommended reduction in utility plant in service and accumulated reserve for his recommended disallowance. He recommended the Commission deny CEI South's request to include any of the IT investments described by Mr. Bahr in rate base.

CEI South witness Bahr noted on rebuttal that Mr. Compton proposed a broad disallowance and rejection of all IT investments without specifically identifying any proposed investments he considered unnecessary or excessive. Pet. Ex. 8-R at 2. He stated that, while Mr. Compton may be looking for a formal study, report, or analysis to justify or support the IT investments included within this Cause, in his 22 years of experience, IT departments do not necessarily conduct formal studies or analysis to evaluate which or whether IT software or hardware requires replacement or upgrade. He stated these requirements to replace, update, or upgrade software or hardware are also often recommended or necessitated by a vendor, citing examples such as the many iterations of Microsoft Windows software or hardware such as Intel Pentium processors or an aging iPhone. He testified this is the type of scenario driving considerable portions of the IT investments CEI South is making. Mr. Bahr explained that instead of formal studies and analysis, third-party or otherwise, IT investments are determined based on a variety of factors that include, but are not limited to, alignment to overall strategy, efficiency, or business continuity; supportability (*i.e.*, end of life or unsupported systems); performance and age; vulnerability and reliability; and functionality or customer/end user benefits. He reiterated that aside from an end-of-life driver (*i.e.*, the above example where the application or system is no longer supported or available as a technology option), age, functionality, performance, and reliability are closely linked factors when evaluating the need to update or replace technology. Mr. Bahr opined that Mr. Compton's characterization that CEI South did not provide any analysis to support the IT investments was not a fair characterization. He said that, aside from his explanation of the investments and drivers requiring the update or replacement within his direct testimony, CEI South responded to several data requests and produced a large volume of supporting attachments concerning these IT investments. Copies of relevant discovery responses were attached to Mr. Bahr's rebuttal testimony at Petitioner's Exhibit No. 8-R, Attachment RWB-R1 (Confidential). Mr. Bahr pointed to his direct testimony on the obsolescence of certain IT programs and the benefits to be realized upon their replacement or update. He stated that Mr. Compton's assertion that CEI South did not make any claim of obsolescence regarding its software or hardware is incorrect. He referenced discovery responses that indicated not only how CEI South systems might improve but gave examples of how IT investments will improve the system or reduce maintenance. Mr. Bahr testified that it is not incongruous to understand benefits can arise from areas other than a pure headcount view, citing reductions in software or hardware maintenance costs, streamlined training costs and other external support costs realized or anticipated to be realized due to a harmonization, or consolidation of platforms. Mr. Bahr also cited increased resiliency stemming from the IT investments his testimony supports. He explained that it is difficult to quantify the support and maintenance reductions for the EIP Phase 2 investment, because the license, support, and maintenance costs are not expected to materially change until the applications he identified are decommissioned, a process which usually occurs within 12-24 months after go-live of the updated or replaced application and is dependent on several factors.

The Settlement Agreement does not expressly address the OUCC's proposed disallowance from rate base of CEI South's IT investments. The stipulated rate base Section B.3.a does not exclude these investments. By virtue of Section B.15.b of the Settlement Agreement, the Settling Parties stipulated that the issue would be resolved as proposed and supported in CEI South's case-in-chief. CEI South expressly supported, but did not modify, its position on the IT investments included in rate base on rebuttal.

OUCC witness Compton testified that accepting the IT investments amount inherently included in the Settlement Agreement is not in the public interest because CEI South has not substantiated the prudency and/or reasonableness of the investments. Pub. Ex. 5-S at 6. He contended that CEI South's discovery responses effectively take the position that the burden of proof lies with the intervening parties and that the Commission is obligated to take CEI South's word at face value and approve all its requested IT investments without further discussions. He stated CEI South's analysis of prudency regarding its IT investments is, however, not comprehensive and places an arbitrary emphasis on qualitative metrics.

iv. <u>Commission Discussion and Findings</u>. While the disputed rate base items were narrowed considerably by CEI South's rebuttal and settlement positions, the OUCC continues to oppose inclusion of certain Steam Production Plant investments and IT-related investments in Petitioner's rate base. We will address each of those disputes, and their proposed resolution in the Settlement Agreement, in turn.

With respect to Mr. Krieger's proposed disallowance for items he believes were improperly capitalized, the record shows that, with the potential exception of 21 items identified in CEI South's Response to our docket entry dated April 29, 2024, CEI South has accounted for these items properly, and Petitioner's capitalization policy and the FERC USOA support Petitioner's capitalization of these expenditures. CEI South's capitalization policy states "Company expenditures for items that have a useful life greater than one year or that extend the useful life of an existing asset by more than one year, that meet the minimum dollar thresholds, and that are not intended for sale in the ordinary course of business shall be capitalized as per the guidance outlined below." Pet. Ex. 22-R at 4. At Instruction 10, the USOA states:

A. For the purpose of avoiding undue refinement in accounting for additions to and retirements and replacements of electric plant, all property will be considered as consisting of (1) retirement units and (2) minor items of property. Each utility shall maintain a written property units listing for use in accounting for additions and retirements of electric plant and apply the listing consistently.

B. The addition and retirement of retirement units shall be accounted for as follows:

(1) When a retirement unit is added to electric plant, the cost thereof shall be added to the appropriate electric plant account, except that when units are acquired in the acquisition of any electric plant constituting an operating system, they shall be accounted for as provided in electric plant instruction 5.

(2) When a retirement unit is retired from electric plant, with or without replacement, the book cost thereof shall be credited to the electric plant account in which it is included, determined in the manner set forth in paragraph D, below. If the retirement unit is of a depreciable class, the book cost of the unit retired and credited to electric plant shall be charged to the accumulated provision for depreciation applicable to such property. The cost of removal and the salvage shall be charged or credited, as appropriate, to such depreciation account.

C. The addition and retirement of minor items of property shall be accounted for as follows:

(1) When a minor item of property which did not previously exist is added to plant, the cost thereof shall be accounted for in the same manner as for the addition of a retirement unit, as set forth in paragraph B(1), above, if a substantial addition results, otherwise the charge shall be to the appropriate maintenance expense account.

(2) When a minor item of property is retired and not replaced, the book cost thereof shall be credited to the electric plant account in which it is included; and, in the event the minor item is a part of depreciable plant, the account for accumulated provision for depreciation shall be charged with the book cost and cost of removal and credited with the salvage. If, however, the book cost of the minor item retired and not replaced has been or will be accounted for by its inclusion in the retirement unit of which it is a part when such unit is retired, no separate credit to the property account is required when such minor item is retired.

(3) When a minor item of depreciable property is replaced independently of the retirement unit of which it is a part, the cost of replacement shall be charged to the maintenance account appropriate for the item, except that if the replacement effects a substantial betterment (the primary aim of which is to make the property affected more useful, more efficient, of greater durability, or of greater capacity), the excess cost of the replacement over the estimated cost at current prices of replacing without betterment shall be charged to the appropriate electric plant account.

Pet. Ex. 22-R at 4-5.

In essence, “retirement units” are the lowest level of asset record that a utility keeps and it consists of “those items of electric plant which, when retired, with or without replacement, are accounted for by crediting the book cost thereof to the electric plant account in which it is included.” USOA Instruction 34. Minor items of property are “the associated parts or items of which retirement units are composed.” USOA Instruction 18. The USOA requires that “[e]ach utility shall maintain a written property units listing for use in accounting for additions and retirements of electric plant and apply the listing consistently.” USOA Instruction 10A.

In response to our April 29, 2024 docket entry (Pet. Ex. 23), CEI South identified only 21 individual listings for projects that were placed in service since the cutoff in Petitioner’s last rate case and that would be in test year end rate base in this case that “may” be component parts of retirement units. The total of these items is $2.3 million, and the evidence merely shows that CEI South’s records do not disclose the reasons the decision was made to capitalize them. The evidence supports CEI South’s capitalization practices, and we cannot agree with Mr. Krieger that there is evidence of “egregious” or any other violation of the applicable accounting guidelines. The record does not support Mr. Krieger’s disallowance and does not rise to the level of rejection of the Settlement Agreement as not in the public interest over what amounts to an immaterial discrepancy in the historical justification for capitalization of a mere 21 items out of thousands for which the record shows the justification remains intact. We reject Mr. Krieger’s arguments against capitalization of these items.

We also find that the OUCC’s recommendation that an audit be conducted of CEI South’s capitalization of maintenance expenses is unreasonable and ignores the evidence presented on rebuttal and in response to our April 29, 2024 docket entry. The record reflects that CEI South’s financial statements are already subject to annual audits by a firm of certified public accountants for compliance with GAAP and the FERC USOA and the Petitioner undergoes considerable diligence to ensure that capitalization decisions are correct. While we find the discrepancy to be immaterial and have no compelling reason to believe Petitioner had materially misstated its rate base, we will highlight this history to inform the Petitioner’s auditors of this risk of material misstatement.

In this Commission’s Order dated July 3, 2024 in Cause No. 38708 FAC 137 S1, we found that CEI South acted reasonably and prudently with respect to the events that gave rise to the June 24, 2022 through March 14, 2023 Culley 3 outage. As such, we find in this case that there is no basis for the disallowance of the $7.8 million in investments to restore Culley Unit 3 after the outage.

Despite Mr. Krieger’s reiteration of his proposed disallowance of costs related to natural gas conversion for Culley Unit 3, the evidence reflects, and the Settlement Agreement confirms, that these conversion costs are not included in CEI South’s rate base for purposes of setting rates in this Cause.

As for the other major projects at Culley 3, the record reflects that these expenditures were reasonable and prudently incurred and required as a result of OEM-recommended maintenance schedules, regardless of any future plans for the unit's conversion. We reject Mr. Krieger's arguments to exclude these expenditures.

With respect to Mr. Krieger's proposed disallowance for investments related to the coal silo failure, we adhere to our position that "the prudence of an electric utility's actions is not judged with twenty-twenty hindsight. Rather, the Commission will focus on the prudency of the decisions when made, based on the facts and circumstances as they existed at the time." *Southern Indiana Gas & Elec. Co.*, Cause No. 38708 FAC 137 S1 (July 3, 2024), at 9-10, (citing *N. Ind. Pub. Serv. Co.,* Cause No. 38706 FAC 130 S1 (June 15, 2022)); *see also N. Ind. Pub. Serv. Co*., Cause No. 44340 FMCA 12, at 12; *N. Ind. Pub. Serv. Co*., Cause No. 43849 (July 13, 2011), at 11). The evidence reflects that Petitioner acted reasonably based on the facts and circumstances known at the time of the failure. Accordingly, we reject Mr. Krieger's claim of "poor project management" and his proposed disallowance.

With respect to the OUCC's proposed disallowance for IT-related investments, the OUCC's position appears to be based primarily on its perceived lack of support from a formal study. However, we find that it is reasonable to replace outdated or obsolete software (*e.g.*, Adobe Flash) and hardware (*e.g.*, computer with an obsolete processor or dated network adaptors that do not have the latest performance capabilities) with newer technology to reduce risks and improve activities or processes performed by the technology. A formal study to quantify the operational efficiencies that result from such replacement, such as faster response times, better integration between systems, or new feature functionality or improved capabilities for users, is not a requirement for prudency, although capital investments of material size are often supported by one. The evidence demonstrates that the IT-related investments will be used and useful in the provision of electric utility service to customers in the test year, and Petitioner's evidence supports the expenditures with extensive discussion of the benefits of these investments for CEI South and its customers. Because the evidence of record sufficiently substantiates CEI South's investment decision, we reject the OUCC's proposed disallowance.

The Settlement Agreement incorporated several reductions to CEI South's test year end rate base, and we find it reasonably resolves the contested issues while recognizing ongoing capital investment is necessary to maintain safe, reliable, efficient, and environmentally compliant service.

E. Return on Equity. Section B.3.c. of the Settlement Agreement stipulates that CEI South's authorized Return on Equity should be 9.80%. Table B.3.c sets forth the stipulated capital structure as of the end of the test year, including the 9.80% ROE, cost of debt and zero cost capital as agreed by the Settling Parties. The resulting weighted average cost of capital is 6.77%, as described in further detail in the Settlement Testimony of Brett A. Jerasa. Settling Parties' Jt. Ex. 1 at Section B.3.c; Pet. Ex. 19-S at 11.

Section B.3.d of the Settlement Agreement stipulates that the agreed weighted cost of capital times the stipulated net original cost rate base yields a fair return on the fair value of rate base for purposes of this case. Accordingly, the Settling Parties agreed that CEI South should be authorized a fair return of $187,518,958, yielding an overall return for earnings test purposes of

6.77%, based upon the stipulated net original cost rate base, capital structure, and ROE. Settling Parties' Jt. Ex. 1 at Section B.3.d.

i. <u>CEI South's Case-in-Chief</u>. Ms. Bulkley estimated CEI South's cost of equity by applying traditional estimation methodologies to a proxy group of comparable utilities, including the constant growth form of the Discounted Cash Flow ("DCF") model, the Capital Asset Pricing Model ("CAPM"), the Empirical Capital Asset Pricing Model ("ECAPM"), and a Bond Yield Risk Premium ("BYRP" or "Risk Premium") analysis. Her recommendation also considered the following factors: (1) CEI South's small size; (2) flotation costs; (3) CEI South's capital expenditure requirements; (4) the regulatory environment in which CEI South operates; (5) CEI South's customer concentration; and (6) CEI South's projected capital structure as compared to the capital structures of the proxy group companies. While she did not make specific adjustments to her ROE recommendation for these factors, she did consider them in the aggregate when determining where her recommended ROE falls within the range of the analytical results. Pet. Ex. 13 at 2-3.

Ms. Bulkley considered the following key factors in her cost of equity analyses and recommended ROE for CEI South in this proceeding:

> (1) The United States Supreme Court's *Hope* and *Bluefield* decisions,[14] which established the standards for determining a fair and reasonable authorized ROE for public utilities, including consistency of the allowed return with the returns of other businesses having similar risk, adequacy of the return to provide access to capital and support credit quality, and the requirement that the result lead to just and reasonable rates;
>
> (2) The effect of current and prospective capital market conditions on the cost of equity estimation models and on investors' return requirements;
>
> (3) The results of several analytical approaches that provide estimates of CEI South's cost of equity. Because CEI South's authorized ROE should be a forward-looking estimate over the period during which the rates will be in effect, these analyses rely on forward-looking inputs and assumptions (*e.g.*, projected analyst growth rates in the DCF model; a forecasted risk-free rate and market risk premium in the CAPM analysis);
>
> (4) Although the companies in her proxy group are generally comparable to CEI South, each company is unique, and no two companies have the exact same business and financial risk profiles. Accordingly, Ms. Bulkley considered CEI South's regulatory, business, and financial risks relative to the proxy group of comparable companies in determining where CEI South's ROE should fall within the reasonable range of analytical results to appropriately account for any residual differences in risk. Pet. Ex. 13 at 3-4.

Ms. Bulkley presented the results of the models she used to estimate the cost of equity for CEI South in her Figure AEB-1, summarizing the range of results produced by the Constant Growth DCF, CAPM, ECAPM, and Bond Yield Risk Premium analyses based on data through the end of September 2023. She noted the range of results produced by the models used to estimate

[14] *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*"); *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*").

the cost of equity is wide and that while it is common to consider multiple models to estimate the cost of equity, it is particularly important when the range of results varies considerably across methodologies.

Considering the analytical results presented in Figure AEB-1, current and prospective capital market conditions, and CEI South's regulatory, business, and financial risk relative to the proxy group, Ms. Bulkley concluded that an ROE in the range of 10.00% to 11.00% would be appropriate, and within that range, an ROE of 10.60% would be reasonable. As discussed in the testimony of Petitioner's witness Richard C. Leger, taking into consideration the affordability for customers of the overall revenue requirement, CEI South requested an ROE of 10.40%.

ii. **<u>OUCC's Position</u>.** OUCC witness Dellinger recommended the Commission approve a 9.0% authorized ROE based on his studies and analysis. He testified that he ran multiple models and identified certain differences between his analyses and those performed by Ms. Bulkley. Pub. Ex. 10 at 4. Mr. Dellinger conducted a constant growth DCF analysis, a two-stage DCF analysis, and two CAPM scenarios as his preferred cost of equity models.

Mr. Compton supported a 0.2% reduction to CEI South's authorized return on equity due to its "lack of transparency and unwillingness to provide the OUCC a general ledger in a manner that provides meaningful, reviewable information." Pub. Ex. 5 at 20.

OUCC witness Latham stated he recommended the Commission accept the OUCC's recommended 8.80% ROE and utilize the OUCC's proposed capital structure incorporating OUCC witness Dellinger's ROE recommendation, which results in a WACC of 6.29%. Pub. Ex. 2 at 9.

OUCC witness Eckert complained of "roadblocks" encountered by the OUCC in its efforts to review CEI South's case-in-chief, citing formula errors, hardcoded numbers, an "unwillingness to provide information in a timely manner," an "unwillingness to provide a transparent general ledger," and informal meetings that proved "unproductive and required the OUCC to issue additional discovery." Pub. Ex. 1 at 24-25. He ultimately recommended the Commission reduce Petitioner's ROE to incent CEI South to approach future cases in a "more cooperative and transparent spirit."

Mr. Compton elaborated that although CEI South provided its general ledger for the historic base period, the format in which it was provided did not allow the OUCC to effectively complete its review. Pub. Ex. 5 at 12. He said a meaningful analysis of the general ledger can only be completed when descriptions for *all* transactions are provided. On this basis, he recommended the Commission authorize CEI South a less favorable return on equity than supported by OUCC witness Dellinger.

Ms. Stull elaborated on the OUCC's complaints with Petitioner's revenue requirement model. She identified four material "deficiencies": (1) the financial model presented in Exhibit No. 20 does not include the entire forecast because amounts were hard-coded; (2) the financial model presented only the overall revenue requirement and rate increase proposed; (3) a majority of the inputs to the schedules and workpapers were merely hard-coded cell entries, with no indication as to how the amount was determined or the basis for the calculation of the amount entered; and (4) lack of detailed supporting calculations for the adjustments that are included in

Petitioner's Exhibit No. 20. Pub. Ex. 6 at 30. Ms. Stull opined that, to allow a reasonable review of its revenues and expenses, any utility using a forward-looking test year must provide the forecast for each month of the forward-looking test year and each month of the linking period. Such provision also allows the reviewer to determine whether Petitioner is being consistent in its forecasting methodologies. It also aids in verifying the rate increase Petitioner states for each phase of its proposal. It is not enough for Petitioner to merely describe in testimony what it proposes. It is also necessary to provide the amounts and calculations in its financial forecast model so that it can be verified that what Petitioner said it was proposing was supported.

OUCC witness Eckert also raised concerns that CEI South has ranked 16th out of the 16 utilities in the "Midwest Region" "Midwest Segment" in J.D. Power Customer Satisfaction surveys in four of the last five years, with 2020 being the exception when CEI South was ranked 15th. Pub. Ex. 1 at 18-19.

iii. **CAC's Position.** CAC witness Inskeep opposed CEI South's proposed ROE, arguing it "reflects an excessive profit margin for CenterPoint's shareholders at the cost of higher rates for its customers." CAC Ex. 2 at 39. He opined that "high ROEs distort utility incentives to over-invest in capital, potentially leading to even more customer bill increases in the future, as it creates a distorted incentive for the utility to invest more than is reasonable in utility plant." He recommended that the Commission should significantly reduce CEI South's currently authorized ROE and set it at the lowest end of the range that the Commission determines to be reasonable.

Mr. Inskeep also referenced the J.D. Power annual Electric Utility Residential Customer Satisfaction Study, saying CEI South has ranked extremely poorly in residential customer satisfaction in every year since at least 2015. CAC Ex. 2 at 39-41.

iv. **IG Position.** IG witness Gorman opined that CEI South's requested ROE of 10.4% is excessive and would result in unjust and unreasonable rates being imposed on CEI South's customers. IG Ex. 1 at 6. Mr. Gorman conducted two constant growth DCF analyses (*i.e.*, one relying on analysts' projected earnings per share ("EPS") growth rates and another relying on a sustainable growth rate), a two-stage DCF analysis, two CAPM scenarios, and a Risk Premium analysis. While the results of Mr. Gorman's costs of equity models ranged from 9.20% to 9.80%, he condensed his recommended range by review of all his market return estimates that showed the current market ROE falls in the range of 9.20% to 9.65%, with an approximate midpoint estimate of 9.45%. IG Ex. 1 at 99. Mr. Gorman then reduced his midpoint ROE estimate of 9.45% by 25 basis points as a downward risk adjustment, stating that the adjustment is to "offset some of the excessive cost to ratepayers created by CEI South's unreasonable equity-thick ratemaking capital structure and mitigate, in part, its cost of service increase and the related adjustment to tariff rate charges in this case."

v. **CEI South Rebuttal.** On rebuttal, Ms. Bulkley testified that the primary factors that should be considered in evaluating the results of the cost of equity analyses and establishing the authorized ROE are: (1) the importance of investors' actual return requirements and the critical role of judgment in selecting the appropriate ROE; (2) the importance of providing a return that is comparable to returns on alternative investments with commensurate risk; (3) the need for a return that supports a utility's ability to attract needed capital at reasonable terms; (4) the effect of current and expected capital market conditions; and (5) achieving a reasonable balance between the interests of investors and customers. Pet. Ex. 13-R at 3-4. She testified that nothing in the testimony of Mr. Dellinger, Mr. Gorman, Mr. Eckert, or Mr. Inskeep has caused her to change her recommendations. She updated her cost of equity estimation models to reflect the most current data, which demonstrated that the model results continue to support her recommended ROE of 10.6% and therefore the 10.4% ROE requested by CEI South remains reasonable.

With respect to Mr. Eckert and Mr. Inskeep, Ms. Bulkley testified that neither Mr. Eckert nor Mr. Inskeep have conducted any analysis to estimate the ROE for CEI South, nor have they conducted a relative comparison of the risk of the utilities of the proxy group companies relative to CEI South. Therefore, she contended there is no basis for either Mr. Eckert or Mr. Inskeep to comment on the relative risk of CEI South to the proxy group, let alone conclude that the ROE should be reduced by 20 basis points as recommended by Mr. Eckert.

CEI South witness Jerasa testified on rebuttal regarding credit rating agency reports on CEI South. In particular, he noted that on March 19, 2024, S&P updated its outlook on CenterPoint Energy, Inc. and its subsidiaries (including CEI South) to negative,[15] meaning that its rating could be downgraded in the next 12 months if "financial measures weaken due to higher-than-expected leverage stemming from elevated capital spending or weaker than-expected cash flow from pending rate cases."[16] Mr. Jerasa also testified that S&P also lowered the standalone credit profile on CEI South to A-minus from A to reflect weaker financial measures. He testified that the outcome of this rate case, including ROE and equity capitalization, will have a material impact on CEI South's credit ratings and future prices demanded by investors to purchase CEI South's debt. Pet. Ex. 14-R at 6. In light of S&P's comments, Mr. Jerasa testified that he disagreed with Mr. Gorman's assertion that a decrease in ROE from 10.4% to 9.2% would protect CEI South's financial integrity, support its current ratings, and not result in close rating agency scrutiny on the impact to CEI South's long term cash flows. He stated that Petitioner's projected 5.12% cost of debt is based upon its current ratings, and a ratings downgrade would increase the cost of long-term debt, impacting not only the capital proposed in this rate case, but any other capital afterwards included in all trackers that update cost of capital and future rate cases, which would increase costs to customers for years to come.

CEI South witness Behme responded to the OUCC's objections to the presentation of CEI South's financial exhibit. She stated there are hard-coded numbers because even if a model were so detailed as to identify every expenditure, employee, customer – it will still ultimately begin with a hard-coded number. She said the revenue requirement model is populated with data pulled directly from CEI South's computer data system. Ms. Behme described an informal meeting held with the OUCC to attempt to provide additional clarity to assist in transparency and noted that Petitioner's confidential "Revenue Model Workpaper" along with other support files produced in discovery were provided to the OUCC. With respect to the general ledger, she indicated the level of detail the OUCC sought simply was too much to be produced in Excel. She further noted the MSFR set forth at 170 IAC 1-5-7(2) requires "a listing of standard monthly journal entries" and

[15] S&P Global Ratings, "Research Update: CenterPoint Energy Inc. and Subsidiaries' Outlook Revised to Negative on Weak Financial Measures; Ratings Affirmed," March 19, 2024.
[16] *Id.*

not a general ledger with transaction descriptions and vendor names. She testified that she did not believe either of the OUCC's two main objections would have been an issue if the OUCC had conducted a site visit during their audit.

CEI South witness Rice responded to the criticism of the J.D. Power scores, acknowledging that they are lower than where CEI South would like them to be and stating CEI South works every day to drive customer satisfaction higher. Pet. Ex. 19-R at 40. He described the recently formed Customer Satisfaction Advisory Team that includes cross functional employees across CenterPoint Energy, Inc.'s footprint with representation from market research, communications, community involvement, billing, contact center, operations, continuous improvement, engineering, safety, IT, and legal functions and with executive sponsorship by the Senior Vice President and Chief Customer Officer. Pet. Ex. 19-R at 40. Mr. Rice explained that customer perception scores are highly correlated with the price a customer pays – as price goes up, overall customer satisfaction drops. He testified that, in 2022, price was the biggest factor driving customer satisfaction lower. Nevertheless, Mr. Rice provided evidence that CEI South was one of only ten Midsized electric companies out of 63 that showed an increase in customer satisfaction in 2023, improving by five points compared to the Midwest, Midsized segment that decreased by 13 points.

vi. Settlement. Mr. Jerasa testified in support of the ROE provided in the Settlement Agreement, explaining that, although it is below the lower bound of Ms. Bulkley's recommended range, the Settlement Agreement represents negotiations among the Settling Parties regarding several otherwise-contested issues. Pet. Ex. 14-S at 3-4. He opined the Settlement Agreement, including an ROE of 9.80%, should be viewed by the rating agencies as constructive and should allow CEI South to attract capital at reasonable rates. Mr. Jerasa testified that Settlements can signal a constructive outcome that balances the needs of the parties and demonstrates the ability of a utility to execute its capital investment plan. Reasonable settlement outcomes demonstrate the constructiveness of a utility's rate recovery and factor into investors' decisions to participate in capital markets issuances. He stated that the rejection of the stipulated ROE contained in the Settlement Agreement would likely signal a non-supportive regulatory environment, which could further deteriorate CEI South's credit ratings and financial integrity, increasing costs for customers in the near- and long-term.

IG witness Gorman opined that the agreed-upon 9.80% in this case is well within the range of reasonableness identified by witnesses in this case.

vii. Settlement Opposition. OUCC witness Eckert recommended the Commission reject the 9.80% ROE agreed upon in the Settlement Agreement, approve the 9.00% ROE calculated and supported by OUCC witness Dellinger, and further reduce the 9.00% by 20 basis points due to what he characterized as issues with Petitioner's reliability, customer satisfaction, and the challenges the OUCC encountered in conducting its analysis of Petitioner's case-in-chief. Pub. Ex. 1-S. Mr. Eckert testified that a lower ROE is warranted based on CEI South's reduced level of risk, particularly when compared to 2011 when its current base rates were established. Pub. Ex. 1-S at 13. He noted the various trackers Petitioner has had approved by the Commission, and stated these trackers shift the risk of increased operating expenses and capital expenditures from utilities to their ratepayers by reducing revenue recovery risk and investors' earning uncertainties. Mr. Eckert testified that a lower ROE is also warranted because, per the J.D. Power surveys, CEI South ranks last or near the bottom in each of the last five years. He referred to past Commission orders in Cause Nos. 43526 and 44576 that adjusted ROE for utility management concerns. Pub. Ex. 1-S at 11.

OUCC witness Compton opposed the agreed-upon ROE and again cited CEI South's significant lack of transparency and unwillingness to provide a comprehensive general ledger. He said these concerns may not have negatively affected the industrial members of the Settling Parties, but Petitioner's reticence and lack of transparency should be addressed as he advocated, not tacitly endorsed. Pub. Ex. 5-S at 3. He acknowledged that CEI South's general ledger includes over three million transactions while Excel limits its spreadsheets to roughly 1.05 million rows. He said CEI South could have simply provided the general ledger with the additional requested information through multiple Excel files instead of just one, just as it had done voluntarily with respect to the multiple Excel files provided when complying with the Commission's MSFRs at 170 IAC 1-5-7(2). CEI South submitted four Excel files for assets and six Excel files for expenses for a total of ten separate files with its case-in-chief.

Ms. Stull opposed the Settlement Agreement in part due to her continued belief that the presence of hard-coded numbers in CEI South's financial model deprived the OUCC of a meaningful opportunity to review CEI South's request. Pub. Ex. 6-S at 13. She maintained that CEI South's financial model is an outlier and lacks much of the information available in the financial models of other utilities who have filed forward-looking test year rate cases. She specifically referenced Indiana American Water Company's model in Cause No. 45870. She opined that the Settling Parties' agreed ROE enables CEI South to "avoid accountability for its lack of transparency."

OUCC witness Dellinger testified that the simple fact that CEI South reduced its ROE request from 10.4% to 9.8% does not make the settled amount reasonable. Pub. Ex. 10-S at 3-4. He stated nothing in Mr. Gorman's settlement testimony indicates that his original ROE recommendation of 9.2% is unreasonable. He noted the 60 basis point increase from 9.2% to 9.8% in the Settlement Agreement would raise Petitioner's requested rate increase by approximately $10.2 million. *Id*. Mr. Dellinger also argued that because the OUCC and other consumer parties did not join this Settlement Agreement, the 9.80% ROE in this case is not a reasonable compromise for the concessions exchanged in the Settlement Agreement.

CAC witness Inskeep testified that the Settlement Agreement's stipulated ROE of 9.8% is "unreasonably high for CEI South given its poor track record when it comes to affordability, reliability, and customer satisfaction, and particularly so given the extraordinary residential bill increase proposed." CAC Ex. 6 at 19. He urged the Commission to find that the Settlement Agreement should be rejected as it would further erode CEI South's customer satisfaction.

viii. **Settlement Rebuttal.** IG witness Gorman testified that Mr. Dellinger's testimony appears to assume that the Industrial Group should have insisted that the Settlement adopt either the OUCC's litigation position on ROE (8.8%), or the Industrial Group's litigation position on ROE (9.2%). IG Ex. 6 at 3. Mr. Gorman stated that, while he believes the ROE analysis in his direct testimony is reasonable, he recognizes that there is risk that his position would not be fully adopted in a litigated outcome. Mr. Gorman explained that, for its part, CEI South correspondingly recognizes the risk that CEI South's litigation position would not be fully adopted in a litigated outcome, either. Mr. Gorman stated his recommendation for approval of an

ROE that is between the parties' positions is not, as Mr. Dellinger alleges, a "discrepancy" in his testimony, but is rather recognition of the reality of the risk that is inherent in litigation.

CEI South witness Rice stated that the punitive ROE sought by the OUCC accounted for approximately $18 million of the $31.7 million difference between the settled revenue increase and the OUCC's filed position. He testified that the OUCC cited no vertically integrated electric utility in the country with an authorized ROE that is that low. Pet. Ex. 19-SR at 4.

Mr. Rice responded to Ms. Stull's and Mr. Compton's opposition related to their assertion of a lack of transparency, reasserting the arguments he made on rebuttal.

In Attachment MAR-SR2 to his settlement rebuttal testimony, Mr. Rice reiterated the options CEI South has proposed that could help with customer satisfaction that the OUCC continues to oppose, including the CPP Pilot, Rider ADR, and the Green Energy Rider. Pet. Ex. 19-SR, Attachment MAR-SR2 at 1; Pet. Ex. 19-R at 42.

CEI South witness Jerasa opined that the 8.8% ROE proposed by the OUCC is unreasonable, 100 basis points below the Settlement Agreement, does not support CEI South's financial integrity, and would be ultimately harmful to CEI South's customers. Pet. Ex. 14-SR at 2. He testified that an 8.8% ROE would signal to investors, the rating agencies, and customers that Indiana is not supporting the investment necessary for reliability, resilience, stability, and environmental sustainability. He also opined that the proposed 8.8% ROE would have a negative impact on affordability for present and future generations due to probable credit downgrades and higher borrowing costs. He explained that 9.80% is not just "within the range of results" but is in fact what the financial community expects when compared to CEI South's Indiana peers and the vertically integrated electric industry in general. He said the Settlement Agreement, including an ROE of 9.8%, should be viewed by the rating agencies as constructive and should allow CEI South to attract capital at reasonable rates since the ROE is comparable to other vertically integrated electric utilities.

ix. <u>Commission Discussion and Findings</u>. The ROE is intended to provide a utility with a reasonable opportunity to attract capital on terms comparable with businesses of similar risk. In setting the rate of return, the Commission's decision must be framed by *Bluefield Waterworks & Improvements Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923) and *Fed. Power Comm'n v. Hope Natural Gas, Co.*, 320 U.S. 591 (1944); *see also Indianapolis Power & Light Co.*, Cause Nos. 44576 and 44602 (March 16, 2016), at 41. The general standards these cases established require a ROE set by the Commission to be sufficient to establish a rate of return that will maintain the utility's financial integrity, attract capital under reasonable terms, and be commensurate with the returns of other businesses of comparable risk.

Both the OUCC and CAC have asked for punitive measures based on poor customer satisfaction ratings (inextricably tied to price/complaints over high rates) and a perceived lack of transparency in Petitioner's presentation of its case. We find these arguments unsupported by the evidence. Petitioner's presentation of its case is: (1) nearly identical to that of its most recent gas rate case and the gas rate case of its affiliate Indiana Gas Company, Inc. d/b/a CenterPoint Energy Indiana North; (2) similar to the presentation of other electric utilities' forward-looking test year rate cases; and (3) built differently from the forward-looking test year rate cases of Indiana-

American Water Company, Inc., which the OUCC cited to point to a lack of accountability by Petitioner. None of this supports a finding that Petitioner has failed to carry its burden or otherwise requires disciplinary action over the presentation of its case or a lack of transparency. There was extensive testimony offered to describe how Petitioner developed its forecasted test year and extensive discovery conducted in this case, and the record reflects Petitioner responded to discovery in a timely manner and made reasonable attempts to provide the OUCC with the information sought. *See ,e.g.*, Pet. Ex. 2 (Behme) at 32-33; Pet. Ex. 3 (Gray) at 3-13; Pet. Ex. 4 (Rawlinson) at 6-9 and 23-25; Pet. Ex. 5 (Folz) at 20-25 and 29-30; Pet. Ex. 6 (Maurer) at 2-9; Pet. Ex. 7 (Bradford) at 6, 13-17; Pet. Ex. 8 (Bahr) at 8-29; Pet. Ex. 9 (Wood) at 8-13; Pet. Ex. 10 (Williford) at 9-10; Pet. Ex. 14 (Jerasa) at 3-5; Pet. Ex. 15 (Story) at 13-19; Pet. Ex. 16 (Russo) at 2-14; Pet. Ex. 17 (Forshey) at 18; *see also* Pub. Ex. 6 (Stull), Attachment MAS-8. The OUCC's own testimony acknowledges the vast amounts of data Petitioner provided with respect to its general ledger. Moreover, regarding the J.D. Power Customer Satisfaction survey results, the record reflects that, relative to its peers, CEI South is improving both in rates relative to other utilities[17] as well as in customer satisfaction.

In Cause No. 46038, the Commission recently found that an ROE of 9.75% is fair and reasonable for Duke Energy Indiana. Notably, Duke Energy Indiana has a larger customer base than CEI South and an adjustment to account for their different size-related level of risk could be warranted. The record reflects that the agreed 9.80% ROE in the Settlement Agreement is within the range of evidence the Settling Parties presented and is within the range of current Commission-authorized ROEs or negotiated ROEs for other Indiana investor-owned utilities. Furthermore, in comparison, CEI South's ROE is appropriately based given a measured adjustment for utility size. The agreed ROE benefits ratepayers by reducing the return on rate base reflected in customers' rates as compared to CEI South's initial proposal. The record further shows the agreed ROE is an important part of the overall settlement package and that it is essential that Petitioner be provided the opportunity to earn an ROE that is consistent with the market. The Commission finds that, as part of the Settlement Agreement, the agreed ROE balances the parties' concerns while preserving Petitioner's financial integrity and should, therefore, be approved.

F. <u>Depreciation Rates and Amortization</u>. The Settlement Agreement provides for adoption of the OUCC's proposed depreciation accrual rates, except for the CT Project and Posey Solar, which will remain unchanged. It also provides for a three-year pass-back of state EADIT, with no carrying charges. Because the EADIT will flow through the TAR, this stipulated term does not affect the revenue requirement. In addition to this specific amortization term related to EADIT, the Settlement Agreement obligates CEI South to file a revised tariff to remove annual amortization amounts from base rates upon each such expiration, unless a new general rate case petition is pending at that time.

i. <u>Depreciation</u>.

1. <u>CEI South's Case-in-Chief</u>. Petitioner proposed new depreciation accrual rates for its electric and common plant and presented a depreciation study prepared by witness Spanos. For purposes of his calculations, Mr. Spanos included generation decommissioning estimates prepared by witness Kopp. Pet. Ex. No. 12. While Mr. Spanos

[17] See Pet. Ex. 19-SR at 8.

calculated depreciation accrual rates for the CT Project and for Posey Solar, Petitioner proposed to maintain the lower rates approved in the CPCN proceedings for the CT Project and Posey Solar in Cause Nos. 44564 and 45847, respectively. Petitioner also chose to have Mr. Spanos calculate depreciation rates using the Average Life Group method rather than the Equal Life Group method, producing an additional savings of $12.5 million in the revenue requirement. Pet. Ex. 1 at 15.

2. <u>OUCC's Position</u>. OUCC witness Garrett made several suggested changes to the calculations presented by Mr. Spanos. He removed contingency costs from the decommissioning estimates, adjusted several mass property account service lives, and recommended adjustments to proposed net salvage rates for several mass property accounts. His recommendations produced a $5.1 million reduction in CEI South's revenue requirement. Pub. Ex. 11 at 3. He proposed rates for the CT Project and Posey Solar that were higher than CEI South had proposed. Pet. Ex. CX-1.

3. <u>CEI South's Rebuttal</u>. In rebuttal, Mr. Spanos responded to all the critiques and adjustments recommended by Mr. Garrett and continued to support CEI South's originally filed depreciation rates. Pet. Ex. 12-R.

4. <u>Settlement</u>. The Settlement Agreement provides for the adoption of the depreciation accrual rates recommended by Mr. Garrett except for the rates for the CT Project and Posey Solar. For those two generation stations, the Settlement Agreement provides for the continuation of the rates approved in the CPCN orders for those projects. There was no opposition to this term.

ii. <u>Amortization</u>.

1. <u>CEI South's Case-in-Chief</u>. CEI South witness Behme presented the calculation of amortization expense related to regulatory assets and liabilities. Pet. Exhibit 2, pp. 24-30. Included in these amortizations were two income tax-related deferred liabilities sponsored by CEI South witness Story. Witness Story proposed that Indiana state EADIT be returned to customers over a five-year period, to match the period used in Cause Nos. 45447 and 45468. The pass back would be accomplished through the TAR and outside of base rates. Pet. Ex. 15 at 13. Ms. Story also sponsored amortization of a deferred Medicare Tax liability over five years. Pet. Ex. 15 at 19; Pet. Ex. 2 at 30.

2. <u>OUCC's Position</u>. OUCC witness Baker opposed the amortization of the deferred Medicare Tax liability because the amortization had been authorized in Petitioner's prior rate case and should have been completed already. Pub. Ex. 4 at 9. Witness Stull recommended that Indiana EADIT be passed back to customers over a three-year period. She made this recommendation because there is no requirement to normalize any portion of state EADIT as there is with protected federal EADIT. She also requested that state EADIT accrue carrying charges. Pub. Ex. 6 at 5-8.

3. <u>Industrial Group's Position</u>. Mr. Gorman also recommended that Indiana state EADIT be returned to customers over a three-year period. He did not recommend the accrual of carrying charges. IG Ex. 1 at 10-13.

4. **<u>CEI South's Rebuttal</u>.** Witness Story continued to advocate a five-year pass-back of state EADIT. She also explained why carrying charges on the balance were inappropriate. Regarding Ms. Stull's argument that the delay in implementing the pass back of state EADIT means customers have been deprived the use of money that has subsequently been devalued by inflation, Ms. Story responded that customers have already enjoyed the value of this balance. EADIT formerly (before the tax rate reduction) was deferred income tax. It was reflected in the capital structure at zero cost. After the tax rate reduction began, EADIT continued to be reflected as a zero-cost source of capital. As such, it reduced Petitioner's authorized rate of return. To now accrue carrying charges would be double counting. Ms. Story noted that Ms. Stull did not cite any other occasion in any rate case where carrying charges have been accrued on the state EADIT balance. She stated CEI South should not be singled out and treated differently from other similarly situated utilities. Finally, Ms. Story testified that CEI South could have lawfully begun amortizing the state EADIT balance in 2011 but it did not. With respect to Ms. Stull's and Mr. Gorman's arguments that the state EADIT should be amortized over three years instead of five, Ms. Story noted recent Commission decisions determining state EADIT should be normalized and not flowed back more quickly and the fact that CEI South's gas utility amortizes the balance over a five-year period.

Witness Behme responded to witness Baker's opposition to the amortization of the Deferred Medicare Tax Liability. She noted that this amortization produces a decrease to the revenue requirement. Pet. Ex. 2-R at 21.

5. **<u>Settlement</u>.** CEI South witness Rice stated Section B.4.b of the Settlement Agreement reflects an amortization period of three years for Indiana state EADIT as proposed by OUCC witness Stull and Industrial Group witness Gorman. Pet. Ex. 19-S at 12. He explained stipulating and agreeing to this settlement provision accelerates the amount being returned to customers, increasing the amount by $1,521,643 per year over the three-year period. However, the Settlement Agreement does not adopt OUCC witness Stull's further recommendation to impose carrying charges. He stated the total $11,412,320 in Indiana state EADIT is proposed to be passed back through the TAR. As such, this stipulated term does not affect the revenue requirement but helps mitigate the bill impact by lowering customer bills and furthering gradualism. Section B.4.b of the Settlement Agreement also stipulates that if not already addressed by an intervening base rate case order before the expiration of various amortization periods, CEI South agrees to file a revised tariff to remove the annual amortization portion from base rates unless a new general rate case petition is pending at that time.

There was no settlement opposition to either of these amortization terms.

iii. **<u>Commission Discussion and Findings</u>.** Neither the settled depreciation term nor the amortization terms were opposed. We find both to be reasonable compromises based upon the evidence and therefore approve them.

G. **<u>Pro Forma Revenues and Expenses</u>.** Section B.5 of the Settlement Agreement provides for adjustments to pro forma revenues and expenses, totaling $15,250,808, to address issues raised by the parties, including: (1) base cost of fuel, (2) interruptible sales billing credits, (3) capacity purchase costs, and (4) O&M expense.

Specifically, these adjustments incorporate recommendations from OUCC witnesses Eckert and Lantrip with respect to the base cost of fuel and interruptible sales billing credits, reduce the forecasted level of capacity purchase costs in the test year, and reduce the level of O&M expense to achieve a level representing a compromise on various reductions to O&M expense recommended by the OUCC and other intervenors. The overall reductions to forecasted test year O&M expense for purposes of the revenue requirement are partially offset by inclusion of $813,540 related to cloud computing arrangements in exchange for Petitioner's withdrawal of its request for regulatory accounting treatment with respect to those arrangements. Pet. Ex. 19-S at 13-14.

i. <u>CEI South's Case-in-Chief</u>. CEI South witness Gray presented the unadjusted forecasted test year financial data. Pet. Ex. 3, Attachment SEG-1 and Schedules C-1.1, C-1.1a, and C-2.1 within Petitioner's Exhibit No. 20.

In her direct testimony, Ms. Behme described various adjustments to CEI South's pro forma level of operating revenues and expenses, including for the following items: (1) removal of Section 24 contract revenues, (2) adjustments related to CEI South's 44910 TDSIC and 45894 TDSIC, (3) adjustments for annualized CECA revenues and removal of levelized rate projects, (4) adjustments associated with the ECA rider, (5) annualized DSMA revenue and allocation of DSMA over/under-recoveries to the rate classes from miscellaneous revenues, (6) allocation of MCRA over/under-recovery to the rate classes and matching of forecasted MCRA revenues with recoverable expenses, (7) allocation of RCRA over/under recovery to the rate classes and matching of forecasted RCRA revenues with recoverable expenses as well as to reflect anticipated purchases of capacity from a demand response aggregator, (8) adjustments to EADIT to reflect amounts forecasted to be passed back through the proposed TAR, (9) similar adjustments for EADIT related to securitization of A.B. Brown, (10) adjustments to reflect the change in operating revenues and operating expenses for normalized FAC associated with F.B. Culley Unit 2, (11) removal of operating revenues and expenses for RECB projects, (12) adjustments to reflect the change in operating revenues and operating expenses for various adjustments to Miscellaneous Revenue to synchronize to the forecasted test year revenue, (13) an adjustment of $414,956 ($2,074,780 amortized over five years) to increase test year expenses for the estimated incremental rate case costs associated with this proceeding, (14) an increase in operating expenses of $108,034 associated with the proposed five year amortization of COVID-19 deferred expenses, (15) pro forma level of IURC fees, (16) an adjustment in the amount of $9,946,645 to reflect annualized depreciation expense based on plant in service as of December 31, 2025 at the proposed depreciation rates discussed above, (17) removal of expense associated with Troy Solar, (18) removal of expense associated with Crosstrack Solar, (19) increase of $38,459 in VUH shared services charges for the test year, (20) annual amortization expense associated with the AMI deferrals related to PISCC and deferred depreciation, (21) annual amortization expense associated with the regulatory assets for the 44910 TDSIC and the 45894 TDSIC deferred revenues and deferrals related to PISCC and deferred depreciation, (22) annual amortization expense associated with the CECA deferrals, (23) annual amortization expense associated with the ECA deferrals, (24) amortization of PISCC that will accrue to a regulatory asset after completion of F.B. Culley East Ash Pond project, (25) annual amortization expense associated with CT Project deferrals related to PISCC, (26) pro forma adjustments decrease of $560,000 to normalize IRP expense, (27) annualized property tax expense on forecasted tax basis balance of assets as of December 31, 2025, (28) pro forma adjustment of $75,808 decrease to test year expense to annualize the level of uncollectible accounts expense to the latest known level, (29) pro forma adjustment of $160,653 decrease to test year expenses associated with sponsorships including Indianapolis Colts and Ford Center that should have been recorded below the line, (30) pro forma adjustment of $347,401 decrease to test year expense associated with Deferred Medicare Tax Liability, (31) pro forma adjustment increase to test year expense to annualize the partial year operating expense associated with the CT Project, (32) pro forma adjustment increase to test year expense to annualize the partial year operating expense associated with Posey Solar, (33) pro forma adjustment decrease to test year expense associated with F.B. Culley Unit 2 (Phase 3 (end of test year) adjustment only), (34) pro forma adjustment to normalize outage operating expense, (35) pro forma adjustment increase to test year expense of $770,000 pertaining to the SAP S/4HANA Transformation Project described by CEI South witness Bahr, (36) pro forma adjustment decrease to test year expense of $1,368,371 pertaining to ash transportation and ash handling operating expenses that should have been deferred to a regulatory asset during the test year, (37) pro forma adjustment decrease to test year expenses of $159,143 pertaining to non-recurring miscellaneous forecast adjustments to correct FERC 5930 for distribution programs that should have been capitalized, and (38) & (39) Indiana state and federal income taxes for pro forma adjusted test year. Pet. Ex. 2 at 19-31.

CEI South witness Bahr described the IT-related components of the CPP pilot as well as the SAP S/4HANA Transformation Program. He said the expense allocated to CEI South for the SAP S/4HANA Transformation Program is $770,000 for 2025. Pet. Ex. 8 at 28.

ii. <u>OUCC's Position</u>.

1. <u>Base Cost of Fuel</u>. OUCC witness Eckert testified that CEI South is requesting a base cost of fuel that is too high given current market conditions. Petitioner is proposing a $0.048139 per kWh base cost of fuel as compared to the $0.038295 per kWh currently approved base cost of fuel. Mr. Eckert testified the cost of natural gas and the MISO market prices proposed to be used in the base cost of fuel by CEI South were too high. Pub. Ex. 1 at 36. He stated that, as of March 4, 2024, the forecasted cost of natural gas and MISO market prices for 2025 had decreased and are expected to stay low. The OUCC's adjustment lowers fuel costs by $8,175,808. *Id.* at 37.

2. <u>Interruptible Sales Billing Credits</u>. OUCC witnesses Lantrip and Wright recommended denial of CEI South's request to embed $725,000 in interruptible sales billing credits into base rates, due to lack of substantive support. Pub. Ex. 3 at 14; Pub. Ex. 8 at 6. Mr. Wright said CEI South has not provided evidence supporting the revenue adjustment of $725,000, which was based on a 2022 Request for Proposal. He said CEI South did not provide supporting evidence that the RFP represented a reasonable price for the demand response capacity. Pub. Ex. 8 at 6. He expressed concern over the lack of details regarding the function of the contract with an aggregator.

3. <u>Emissions Allowance Costs</u>. OUCC witness Lantrip recommended the Commission deny the Emissions Allowance portion of costs in base rates, contending that Petitioner has not demonstrated prudence regarding the management of its allowance inventory. He recommended embedding a zero balance in base rates and Petitioner's approval of its Emissions Allowance inventory variance be contingent upon an improvement of its practices, as demonstrated through updates of less volatility in inventory levels presented in its RCRA rider testimony. Pub. Ex. 3 at 13-14.

Ms. Armstrong testified that CEI South's allowance cost assumptions to determine forecasted allowance expense do not reflect significant price decreases in the allowance market or the effect of zero-cost allowances allocated to CEI South's generating units. She argued that CEI South's forecasted emission allowance expense is likely to be overstated. Pub. Ex. 7 at 3. She also stated that CEI South's filed exhibits and workpapers did not provide detailed monthly emission allowance inventory calculations by allowance type, which she said was necessary to verify the monthly allowance inventory balance and expense. Ms. Armstrong said Petitioner does not appear to account for zero-cost allowances that will be allocated to its units during the test year. Instead, CEI South's method for estimating test year allowance expense assumes that it will need to purchase NOx allowances for every ton of NOx it will emit, which Ms. Armstrong says likely overstates the total cost of CEI South's allowance purchases in 2025. Since CEI South's actual allowance expenses are tracked through its RCRA, Ms. Armstrong contended it is reasonable to remove all forecasted allowance expense from the test year, thereby mitigating the risk of embedding overstated allowance expense in test year O&M, while providing CEI South the ability to recover allowance costs if future allowance prices increase substantially in reaction to changes in federal air rules. The OUCC's recommendation would remove from the test year $1,282,707 of rate base and $3,519,952 of Emission Allowance O&M costs. Pub. Ex. 3 at 14; Pub. Ex. 7 at 11.

4. <u>IT O&M Expense</u>. OUCC witness Compton recommended the Commission deny CEI South's request to include $770,000 in O&M expense for its SAP transformation program and $813,540 in O&M expense for cloud computing arrangement costs to be incurred in 2025 under the CATO Project. He based his recommendations on what he characterized as CEI South's failure to provide proof of the necessity behind the investments and failure to substantiate the claimed benefits for its system. Mr. Compton testified that CEI South's responses to discovery showed Petitioner performed no study and conducted no analysis to support the benefits it claims from these IT programs. Pub. Ex. 5 at 8.

5. <u>Rate Case Expense</u>. OUCC witness Compton testified that he does not dispute CEI South's estimate for rate case expense of $2,074,780, but he encouraged the Commission to not accept the premise that CEI South's ratepayers should be wholly responsible for reimbursing Petitioner for that expense through its rates. He advocated for rate case expense incurred in this Cause to be borne equally by CEI South as a below-the-line expense, making ratepayers responsible for $1,037,390 and shareholders responsible for $1,037,390, recognizing that significant benefits flow to shareholders. As to CEI South's proposal to recover any unamortized rate case expense in its next rate case, Mr. Compton stated that proposal is acceptable provided CEI South's customers be similarly protected from continuing to pay that expense after the authorized rate case expense has been fully amortized. He recommended CEI South be required to amend its tariff of rates and charges once its authorized rate case expense has been fully amortized to remove that expense from rates. Pub. Ex. 5 at 17. Mr. Compton testified that Indiana statutes do not prohibit the Commission from allowing rate case expenses to be shared among shareholders and ratepayers. He opined that "as evidenced in this case," requiring ratepayers to pay all rate case expenses removes any financial incentive for petitioning utilities to be transparent and cooperative when providing information in its case and through data requests. He asserted that a petitioner's lack of transparency requires the OUCC to ask extensive discovery questions, which, in turn, can increase the legal costs incurred by the utility. He recommended the Commission allow CEI South to collect $1,037,390 amortized over five years for an annual pro forma revenue requirement adjustment of $207,478.

6. <u>Sponsorships</u>. OUCC witness Compton recommended removal of $6,654 for sponsorship of the Ohio Valley Conference Basketball Tournament and $3,025 for the University of Evansville sponsorship, stating these sponsorships are for image building and enhancing relations in the communities in which CEI South operates as well as advertising. Pub. Ex. 5 at 3.

7. <u>Competitive Pay Adjustments</u>. OUCC witness Baker recommended the Commission deny CEI South's requested recovery of a competitive pay adjustment ("CPA") of 3% due to the low number of job vacancies and total salaries being under budget for multiple years during the 2018-2023 period. Pub. Ex. 4 at 1 and 7. She testified that the surveys and studies relied on in CEI South witness Williford's testimony were not appropriate to determine a basis for the proposed CPA. Ms. Baker testified that the survey participants and data are not shown to be a fair comparison to a company of Petitioner's size, location, and characteristics. Ms. Baker testified that her review of base pay and job availability revealed CEI South is not experiencing difficulty maintaining reliable employees and CEI South has been consistently under budget for base pay and has had few job vacancies during the last three years. Ms. Baker also noted that the CPA is not granted to all employees and testified that CEI South did not indicate a separate adjustment to account for a percentage of employees not granted a CPA.

8. <u>Shared Services Expense</u>. OUCC witness Lantrip stated that Petitioner's $38,459 shared services adjustment for the VUH common asset charges should be denied due to lack of support in the Petitioner's case-in-chief. Pub. Ex. 3 at 18.

iii. <u>Industrial Group's Position</u>.

1. <u>Incentive Compensation</u>. Industrial Group witness Gorman recommended removing 70% of LTI tied to the financial performance of CEI South from cost of service, which he calculated to be approximately $1.4 million based on discovery responses indicating forecasted LTI expenses allocated to CEI South in the test year is $2.0 million. Industrial Group Ex. 1 at 8-9. He argued that incentive compensation costs tied to the financial performance of CEI South should not be included in ratemaking cost of service because they are designed to align the interests of employees with those of shareholders and are designed to enhance the value of shareholders' investments in CenterPoint Energy, Inc. and/or CEI South to the extent the financial incentive targets are achieved.

2. <u>Number of Customers</u>. Mr. Gorman also objected to CEI South's use of the average number of customers for the end of test year increase, which he said understated the revenues. He recommended an adjustment to reflect the end-of-test-year customer numbers. IG Ex. 1 at 4-5. This results in an increase in revenue at current rates of $390,000 and a corresponding reduction of the claimed Phase 3 (end of test year) deficiency.

3. Normalized Sales Adjustments. Mr. Gorman recommended that the Commission forecast CEI South's test year sales and revenues at present rates for the residential and commercial classes using a normalized use per customer forecast based on weather normalized historical data. He testified that CEI South is forecasting declining sales per customer due to energy efficiency and other factors that may not be realized. Instead, Mr. Gorman's adjustment relies on a three-year average use per customer for the residential and commercial classes. His recommended adjustment increases revenues at present rates and reduces CEI South's revenue deficiency by approximately $3.6 million. IG Ex. 1 at 9.

iv. CAC's Position.

1. DSMA Costs. CAC witness Barnes opposed the inclusion of DSM program costs in base rates. CAC Ex. 3 at 29. He noted that CEI South had indicated in response to discovery that CEI South would be willing to eliminate its proposal to include DSM program costs in base rates. CAC Ex. 3, Attachment JB-3. However, he stated such a withdrawal will not fully address the issues he identified with respect to allocation of demonstration and sales expenses logged in FERC accounts 911 and 912. CAC Ex. 3 at 28.

2. Rate Case Expense. CAC witness Inskeep recommended disallowance of the entirety of CEI South's rate case expense, testifying that Petitioner's experts and attorneys are working to increase CenterPoint's revenues and profits to benefit CenterPoint shareholders at the literal expense of ratepayers. He stated shareholders, not ratepayers, should pay all, or at least a substantial portion of, costs of experts and counsel in this case. He testified that CEI South was only required to file this rate case because it voluntarily elected to file a TDSIC Plan that ran through the end of 2023 and therefore, this rate case is entirely a result of actions within Petitioner's control and that were done to benefit shareholders. CAC Ex. 2 at 54-55.

3. Trade Associations. CAC witness Inskeep recommended the Commission deny CEI South's request to include in its revenue requirement all expenses related to trade association dues. CAC Ex. 2 at 53. He stated organizations like Edison Electric Institute, Indiana Energy Association, Indiana Manufacturers Association, and Consumer Energy Alliance, to name a few, engage in highly political, advocacy-oriented, and influence activities, which could include funding outside political and charitable contributions, litigation, regulatory advocacy, advertising, and efforts to shape the public and decision-maker opinion, in addition to numerous other activities that principally serve the private interests of the members rather than ratepayer interests. They can also promote contentious political and policy viewpoints that many individual utility customers would find highly objectionable and do not want to fund through their electric bills that they are compelled to pay to maintain essential utility service.

v. SABIC's Position. SABIC witness Coyle testified that CEI South had failed to include $546,518 of transmission revenues in the revenue requirement and the ACOSS. She noted CEI South committed to updating this value on rebuttal, which would lower the overall revenue increase requested in the filing. SABIC Ex. 1 at 39-40.

vi. CEI South Rebuttal. CEI South made various adjustments to its pro forma revenues and expenses on rebuttal, as more particularly described in Ms. Behme's rebuttal testimony and summarized in her Table CMB-R1. Pet. Ex. 2-R at 4.

1. **Base Cost of Fuel.** CEI South witness Rice testified on rebuttal that Mr. Eckert's recommendation was not based upon what people are paying today in the market for future gas but instead was based on the EIA's Short Term Energy Outlook. He said CEI South's forecast for natural gas was a reasonable forecast and lower than where NYMEX Henry Hub Natural Gas Futures (Settlements) are for 2025 at $3.49. Pet. Ex. 19-R at 52. He also disagreed with Mr. Eckert's recommendation to lower the Locational Marginal Price ("LMP") Prices, noting that natural gas prices help set the marginal price for energy, and CEI South's gas price is reasonable.

2. **Interruptible Sales Billing Credits.** CEI South witness Rice explained the calculation of the cost of interruptible sales billing credits and DR aggregator payments was based upon a bid received from a DR aggregator in CEI South's All-Source RFP for DR aggregation in its 2022/2023 IRP. Pet. Ex. 19-R at 27. He explained that this is a new program and CEI South does not yet know how many may participate. He said CEI South currently does not have any commercial and industrial ("C&I") customers in its IC Rider, IO Rider, or MISO tariffs with DR registered with MISO. Accordingly, Mr. Rice explained, CEI South did not include any DR for these tariffs in the forecast for 2025. Given the uncertainty about how many customers will sign with the DR aggregator and uncertainty around potential updates in any of the three other DR tariffs, CEI South proposed a reasonable level of $725,000 to be embedded in base rates, which Mr. Rice said is far less than the $1,686,350 embedded in rates today.

3. **DSMA Costs.** On rebuttal, Ms. Behme indicated that, as described in CEI South's Response to CAC Data Request 5.7 (CAC Ex. 3, Attachment JB-3), CEI South is removing $500,000 in revenues for performance incentives from base rates. She stated performance incentives will remain in the DSMA. Furthermore, Ms. Behme confirmed that CEI South is removing DSMA program costs from base rates, in line with CAC witness Barnes' recommendation. This adjustment involves the removal of expense as well as corresponding revenues. Pet. Ex. 2-R at 6. CEI South witness Rice also testified on rebuttal that CEI South agreed to recover all program costs and the performance incentive in the DSMA tracker rather than base rates. Pet. Ex. 19-R at 50. As such, CEI South removed all revenues and expenses were pulled out of base rates, as described by witness Behme. Summer Cycler costs remain in base rates, as they are today.

4. **Emissions Allowance Costs.** CEI South witness Behme testified on rebuttal that CEI South accepts the OUCC's position presented by witness Lantrip to remove $3,519,952 of emission allowance O&M costs from the test year and instead to track 100% of such costs through the RCRA. Pet. Ex. 2-R at 6.

5. **IT O&M Expense.** In rebuttal, Mr. Bahr reiterated that the $770,000 that Mr. Compton recommended the Commission deny represents the costs allocated to CEI South Electric to migrate the existing SAP ERP 6.0 system to the latest SAP ERP platform – SAP S/4HANA – before the current version's end of life in 2027. Pet. Ex. 8-R at 13. He said CEI South must prepare for this eventuality and it is the costs of doing so that Mr. Compton seeks to disallow. *Id.* He reiterated the benefits to CEI South and its customers of transitioning to the latest SAP platform – SAP S/4HANA.

With respect to the $813,540 CEI South requests to include for the cloud computing arrangement costs to be incurred in 2025 under the CATO Project, Mr. Bahr responded that Mr. Compton may have misunderstood certain points and he did not specify with details or support his recommendation that these costs be denied. Pet. Ex. 8-R at 14. He reiterated what Ms. Behme testified in her direct testimony, that this amount represents “[t]he baseline level of the third-party [CCA] expected to be recorded to expense during the test year . . . which CEI South proposes to recover through base rates and has included in this case[.]” Pet. Ex. 8-R at 14, quoting Pet. Ex. 2 at 37.

Mr. Bahr testified that the majority of the costs are related to Software as a Service (“SaaS”). SaaS solutions are a complete application solution provided by a vendor that is usually accessed by an internet browser or mobile device. Data related to the SaaS is stored in the cloud, allowing access anywhere via the internet. Examples of SaaS software used by CEI South include Microsoft 365 (productivity and collaboration tools like Outlook, Word, Excel, Teams), Oracle HR Solutions (for recruiting candidates, delivering training including compliance training, and employee performance management), and Service Now (IT service management tool used for incident management and change management used to deliver services). A smaller portion of the $813,540 is related to Infrastructure as a Service (“IaaS”), which is a cloud service where a vendor provides computing, storage, and networking resources. Examples for CEI South include Microsoft Azure. Through the CATO program, CEI South is moving on-premise applications to the Microsoft Azure cloud to enhance resiliency, efficiency, and security. The CATO program is a strategic investment that aligns with IT’s Cost Optimization strategy that focuses on operating technology efficiently and delivering services in a more cost-effective manner. By establishing a foundation on the Microsoft Azure cloud, CEI South will gain more flexibility in deploying applications, increase automation of infrastructure operations, and establish a secure environment through multiple layers of defense to improve resiliency of the applications and protect CEI South assets in the cloud. Pet. Ex. 8-R, pp. 14-15.

6. Rate Case Expense. As to rate case expense, Ms. Behme testified on rebuttal that the OUCC’s and CAC’s positions are inconsistent with decades of precedence before this Commission and would result in treatment for CEI South that is different from other large public utilities in the State. Pet. Ex. 2-R at 18.

7. Sponsorships and Trade Associations. CEI South witness Behme testified that CEI South accepts OUCC’s proposed adjustments to A&G for sponsorships in the amount of $9,679. Pet. Ex. 2-R at 16. With respect to trade association dues, Ms. Behme testified on rebuttal that CEI South has followed the methodology and application of prior cases where membership dues have been routinely recovered through rates in Indiana. Amounts attributed to lobbying activities and political contributions have been identified and removed from the cost of service. Ms. Behme explained that these amounts are specifically included on invoices received by CEI South. She argued CEI South’s membership in trade associations such as the Indiana Energy Association provides benefits to CEI South and its customers by providing an opportunity to (among other things) discuss industry issues with peer companies to understand practices, procedures or other measures that can assist CEI South in ensuring the affordability, quality, efficiency, reliability, and security of service.

8. **<u>Incentive Compensation</u>.** CEI South witness Williford testified that the Commission has previously rejected arguments like those put forward by Mr. Gorman regarding incentive compensation. Pet. Ex. 10-R at 6. She testified that the fact that there are financial metrics in an incentive compensation plan does not make it a pure profit-sharing plan, and the Commission has historically not been receptive to excluding recovery of those portions of the plan that are tied to financial metrics. She stated Mr. Gorman did not contend that CEI South's incentive compensation does not satisfy the three-part test this Commission has applied for awarding recovery of incentive compensation. She reiterated how CEI South's incentive compensation satisfies this standard and testified that customers directly and materially benefit from the provision of financially based LTI awards to CEI South's employees, a practice that serves to align the interests of both shareholders and customers. Ms. Williford stated a specific purpose of the LTI plan is to focus employee attention toward ensuring sustained improvements in performance over longer periods of time. She testified that the achievement of strong financial performance is a benefit to both customers and shareholders enabling CNP to adequately maintain its assets and provide safe and reliable electric service to customers with a focus on controlling costs. She testified that LTI is necessary to recruit and retain executives and key employees and that CEI South's peer companies (against whom it competes for executive and key employee talent) provide both performance-based and time-based LTI awards as part of their LTI programs.

9. **<u>Competitive Pay Adjustment</u>.** CEI South witness Williford responded in rebuttal to Ms. Baker's proposed disallowance, stating that, as reflected in CEI South's response to a discovery request, the eligible employees for a CPA are those "[e]mployees who are full-time or part-time and on CEI South's payroll on December 31st of the plan year." Ms. Williford continued referencing the data response, which explained, "a yearly increase is not granted to all employees", rather, "[i]ndividual CPAs are based on performance and salary position to the market (compa-ratio)." Pet. Ex. 10-R at 3. Ms. Williford stated that CEI South's market-based, pay-for-performance philosophy means that CPA awards are not granted in a formulaic method and therefore, not all employees are granted an increase. She explained that the annual budgeted 3% CPA used to estimate CEI South's forecasted spend already accounts for certain employees not receiving a CPA, just as it accounts for certain employees receiving more than 3%; therefore, an adjustment to "account for a percentage of employees not granted a CPA adjustment" is not warranted.

Ms. Williford also testified that CNP does not rely solely on one source for market data, but rather, "uses a variety of national, regional, and local survey data that is refreshed annually to monitor and determine market pay values [with m]ost jobs [being] matched to multiple surveys." She reiterated that her direct testimony not only referenced the median budget increase implemented and reported for 2022 on a national basis but explained a similar "budget trend . . . was reported by those employers with operations in the state of Indiana." Pet. Ex. 10-R at 4. She also explained that CEI South Specific WTW Survey, provided as Attachment DRW-5 (CONFIDENTIAL) to her direct testimony, did compare CNP compensation to utility peer groups similar in size to CEI South, and concluded CNP compensation was aligned to market. CEI witness Bradford responded to Ms. Baker's testimony that the number of job vacancies and total salaries were under budget. He reiterated his direct testimony where he explained how Generation Operations avoided layoffs due to the closure of the A.B. Brown Units 1 & 2 in October 2023, by managing the Generation Operations workforce through attrition from approximately 188 full-time equivalents ("FTEs") in 2019 to approximately 138 FTEs year-end 2023 by utilizing contractors and reassigning the A.B. Brown workforce to other departments within Generation Operations. Mr. Bradford explained it was this diligent management of the workforce, to mitigate employee hardship, that actually drove the variance of actuals to plan and low number of vacancies. Pet. Ex. 7-R at 14.

10. **Shared Services Expense.** Ms. Behme explained in rebuttal that this adjustment is pure math and that whatever the Commission finds as the WACC in this case should be the WACC used in the calculation of VUH asset charge. Additionally, she stated this calculation is using the same mechanics that were used in CEI South's gas rate case filed in 2020. Pet. Ex. 2-R at 21.

11. **TSO Revenues.** In response to SABIC's witness Coyle, CEI South updated the revenue requirement to include $1,349,242 of expected total annual forecasted TSO other revenues. Pet. Ex. 2-R at 6.

12. **Number of Customers and Normalized Sales.** CEI South witness Russo responded to Mr. Gorman's recommended average usage for residential and commercial customers, as well as Mr. Gorman's recommendations with respect to capturing customer growth. Mr. Russo testified that annual average customers are an accurate measure of the customer counts associated with total annual sales, particularly because the customers as of the end of the test year are not projected to be customers for the entire test year and so will not provide the revenues Mr. Gorman proposes. Pet. Ex. 16-R. Regarding Mr. Gorman's concerns that CEI South is understating the residential and commercial use per customer, Mr. Russo testified regarding certain corrections required for Mr. Gorman's calculation and opposed the use of a three-year historical average to determine test-year residential and commercial average use. His forecast model showed that both residential and commercial usage continues to decline.

vii. **Settlement.**

1. **Items Accepted and Incorporated in Settlement.**

A. **Base Cost of Fuel.** CEI South witness Rice testified that the Settlement Agreement incorporates an adjustment to reduce the forecasted base cost of fuel in the test year revenue requirement by $8,175,808 as recommended by OUCC witness Eckert. Pet. Ex. 19-S at 13; Settling Parties' Jt. Ex. 1 at Section B.5.a.

OUCC witness Eckert acknowledged that the Settlement Agreement incorporated his fuel cost and fuel inventory adjustments. Pub. Ex. 1-S at 15.

B. **Interruptible Sales Billing Credits.** Mr. Rice described the adjustment made in the Settlement Agreement to remove $725,000 in interruptible sales billing credits and aggregation demand response, as recommended by OUCC witness Lantrip. He stated any actual interruptible sales billing credits will be reflected in the RCRA. Pet. Ex. 19-S at 13.

OUCC witness Eckert acknowledged that the Settlement Agreement did incorporate CEI South's agreement to remove the interruptible sales billing credits as recommended by Mr. Lantrip.

C. Capacity Purchase Costs. The Settlement Agreement includes an adjustment to reduce forecasted capacity purchase costs in the revenue requirement for the test year by $5,000,000. Settling Parties' Jt. Ex. 1 at Section B.5.c. Mr. Rice explained, however, that CEI South is in the midst of a generation transition, and a level of capacity purchases will be necessary for the foreseeable future. Accordingly, actual costs above or below the remaining base amount will continue to be tracked in the RCRA, and variances will be charged or credited to customers. Pet. Ex. 19-S at 13.

D. Sales Forecast and Incentive Compensation. The Settlement Agreement does not expressly discuss Mr. Gorman's Sales Forecast and Incentive Compensation arguments, but it does provide that "items not expressly delineated herein shall be resolved as proposed in CEI South's case-in-chief, as modified by its rebuttal position." The Settling Parties have agreed that the Settlement Agreement resolves all disputed issues in this Cause, including those raised by IG witness Gorman with respect to Petitioner's sales forecast and incentive compensation.

2. Remaining Disputed Items.

A. Other O&M Expense. Mr. Rice testified that the Settlement Agreement contains an adjustment reducing CEI South's total forecasted level of O&M Expense by $1,350,000. He stated that the reduction is not assigned to particular FERC accounts but is in total. Pet. Ex. 19-S at 13-14.

OUCC witness Compton testified the while rate case expense may have been considered in the $1.35 million reduction in forecasted O&M incorporated into the Settlement, rate case expense is not expressly addressed in the Settlement Agreement. Pub. Ex. 5-S at 3-4. He stated if any of this annual pro forma revenue requirement can be attributed to the agreed $1.35 million reduction in O&M expense, it would not be in the public interest to leave to speculation the extent to which these expenses have been reallocated. He stated the most reasonable assumption is that the Settlement Agreement has accomplished no decrease in rate case expense. He maintained that it is inequitable for ratepayers to pay for the entirety of rate case expense. He said the Settlement Agreement was not in the public interest because it does not pronounce that shareholders are being considered responsible for some of this rate case expense, including the expenses incurred for their prospective benefits from the prosecution of this case.

Mr. Compton also objected to the absence of language in the Settlement Agreement incorporating his recommendation that CEI South also be required to amend its tariff once its rate case expense has been fully amortized.

CAC witness Inskeep expressed concern that the Settlement Agreement fails to adjust the revenue requirement to remove trade association membership dues and rate case expense, which he contends produces rates that are not just or reasonable. CAC Ex. 6 at 19-20.

In Attachment MAR-SR2 to Mr. Rice's Settlement Rebuttal testimony, Petitioner reiterated the rebuttal of Ms. Behme to Mr. Compton's proposed sharing of rate case expense, noting that the mere fact the OUCC may have taken the same position in other cases does not change that the OUCC position has never been accepted by the Commission. Pet. Ex. 19-SR, Attachment MAR-SR2 at 1. Mr. Rice's attachment does indicate that CEI South did not oppose Mr. Compton's recommendation that rates be reduced upon the expiration of the amortization period of rate case expense if an intervening rate case has not been filed.

viii. **Commission Discussion and Findings.** Many of the disputed issues were addressed to the satisfaction of the non-settling parties either through rebuttal or settlement. The overall reduction to O&M expense contained in Section B.5.d of the Settlement Agreement represents further compromise given the various remaining disputes over expense levels. Section B.15.b of the Settlement Agreement provides that all disputed items not expressly delineated in the Settlement Agreement shall be resolved in accordance with CEI South's case-in-chief, as modified by its rebuttal position where applicable, to the extent expressly supported in CEI South's evidence and without waiving the right of any party to litigate such issues in future proceedings. This includes all the relief summarized in this order, which has not otherwise been modified by the Settlement.[18] The Commission finds Section B.15.b of the Settlement Agreement to be reasonable and it is approved. Further findings on certain disputes the OUCC and CAC continue to raise in their opposition to the Settlement Agreement are provided here.

With respect to the OUCC's and CAC's respective positions on disallowance of rate case expense, this Commission has, in the past, considered the propriety of rate case expense as a two-tiered test. The first level of inquiry is whether the item giving rise to the expense is reasonably necessary for the presentation of Petitioner's case. Assuming the satisfaction of the initial level of inquiry, then the next question is whether the expense incurred is reasonable in the light of the service provided. *Indiana Gas Co., Inc.*, Cause No. 38080 (Sept. 18, 1987). This Commission has also rejected invitations by the OUCC to allocate to shareholders rate case expense on previous occasions. See *Gary-Hobart Water Co.*, Cause No. 39585 (Dec. 1, 1993). No adjustment was made specifically with respect to rate case expense in the Settlement Agreement. As a result, pursuant to Section B.15.b, the Settlement incorporates CEI South's case-in-chief position, which we find to be reasonable. We further find that Petitioner shall file revised tariffs upon the end of the amortization period to remove the annual amortization expense from its rates if the amortization period expires before new rates are approved.

With respect to trade association dues, we again decline to depart from our prior findings on this issue. This Commission recently affirmed that inclusion of the non-lobbying portion of such expenses is proper because the collaboration and sharing of best practices benefits customers through more efficient and effective utility service. See *Indiana-American Water Co.*, Cause No. 45870 (Feb. 14, 2024), at 79. The record in this case shows that these organizations provide legitimate benefits for their members and their customers. Pet. Ex. 2-R at 16-17.

H. Regulatory Accounting Treatment – Cloud Computing Costs.

i. **CEI South's Case-in-Chief.** In its Verified Petition, CEI South requested authority to capitalize by establishing a regulatory asset all cloud computing costs not included in base rates. Witness Behme described the proposal and explained the differences for

[18] To the extent not expressly addressed elsewhere in this order, we reject the issues raised by the OUCC in opposition to settlement that were repeating their case-in-chief positions as outlined in Attachment MAR-SR2 to Petitioner's Exhibit 19-SR.

capitalization pursuant to GAAP and ratemaking and cited orders[19] from this Commission concerning the ratemaking for such costs. She then noted that for ratemaking during the test year in this case, Petitioner had followed the GAAP standards and included a forecasted level of cloud computing expense in O&M of $813,540. Petitioner's proposal is to capitalize to a regulatory asset all annual cloud computing expense above that baseline level. Pet. Ex. 2 at 35-37.

ii. **OUCC's Position.** OUCC witness Compton opposed the capitalization of costs that GAAP would treat as expense. He disagreed that it would be difficult to determine which portion should be expensed per GAAP. Pub. Ex. 5 at 8-9.

iii. **CAC's Position.** CAC witness Inskeep also opposed CEI South's request to capitalize cloud computing costs. CAC Ex. 1 at 10.

iv. **Industrial Group's Position.** IG witness Gorman also objected to Petitioner's request for authority to capitalize cloud computing costs. IG Ex. 1 at 135-36.

v. **CEI South's Rebuttal.** Witness Behme responded to the opposition to capitalize the cloud computing costs. She reiterated that CEI South's proposal was consistent with past orders of this Commission and noted that neither Mr. Compton nor Mr. Gorman had addressed those orders. In addition, since the filing of case-in-chief testimony, another order had been issued supporting CEI South's request.[20] Pet. Ex. 2-R at 22-23.

vi. **Settlement.** Mr. Rice described the Settlement term by which the forecasted $813,540 in GAAP expense would be included in O&M but the request for deferral authority above that amount would be withdrawn without prejudice to request again in another docket. This approach allows for more time to see how recovery of cloud computing evolves over the next few years. Pet. Ex. 19-S at 14. Mr. Gorman noted that the cloud computing expense term reflected compromise among the parties. IG Ex. 1-S at 4-5.

vii. **Settlement Opposition.** Mr. Compton testified in opposition to the Settlement Agreement, noting that it withdraws the request for regulatory accounting treatment. He stated that the Settlement Agreement did not expressly address his recommendation to disallow CEI South's IT investments because it did not substantiate the prudency and reasonableness of those expenditures. Pub. Ex. 5-S.

viii. **Commission Discussion and Findings.** We find the Settling Parties' resolution of the Cloud Computing Costs that would be recorded as expense pursuant to GAAP to be reasonable and that the resolution strikes a reasonable compromise, and we therefore approve it.

I. **CAMT, EADIT, and TAR.** Section B.7.b of the Settlement Agreement withdraws CEI South's request to include future CAMT effects in its TAR. The Settlement Agreement acknowledges that the actual effects of the CAMT occurring by the beginning and end of the test year will be reflected in CEI South's capital structure for purposes of Settlement Phase

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[19] *Northern Ind. Pub. Serv. Co.*, Cause No. 45159 (Dec. 4, 2019); *Aqua Indiana, Inc.*, Cause No. 45675 (Jan. 1, 2023).

[20] *Indiana American Water Co.*, Cause No. 45870 (Feb. 14, 2024), at 30-31.

1 and Settlement Phase 2 rates. Settling Parties' Jt. Ex. 1 at Section B.7.b. No party opposed moving the existing EADIT schedules out of the TDSIC rider or inclusion of Production Tax Credits ("PTCs") that were approved to be passed back to customers via the CECA, to the TAR. CEI South still seeks the creation of the new rider for these purposes. Additionally, CEI South proposes to pass state EADIT back to customers through the TAR over a three-year period, per the stipulation in the Settlement Agreement discussed elsewhere in this Order. Pet. Ex. 19-S at 16-17.

i. <u>CEI South's Case-in-Chief</u>. CEI South witness Story presented CEI South's proposed TAR and explained that the IRA contains significant benefits for clean energy and renewable investments impacting the utility industry. Pet. Ex. 15 at 3. She testified that the CAMT was included in the IRA to offset the cost of tax incentives. Ms. Story summarized several provisions of the IRA applicable to public utilities, including:

- Restoration and extension of the renewable electricity PTC and clean electricity investment tax credit ("ITC");
- Creation of new tax credits designed to incentivize investment in renewable energy;
- Establishment of a non-deductible 1% excise tax on certain corporate share repurchases; and
- Imposition of a 15% CAMT based upon adjusted financial statement income ("AFSI").

She said the IRA imposes the new CAMT prospectively on AFSI of an Applicable Corporation for taxable years beginning after December 31, 2022. She said the CAMT represents the means within the IRA to fund the tax credit benefits of the IRA as described in her testimony. She described how the determination is made of whether CAMT must be paid. Ms. Story testified that CEI South is an Applicable Corporation for purposes of the CAMT. However, there will be no CAMT due in 2023. She stated CEI South expects to pay the CAMT in 2024 and 2025 based on current guidance. Ms. Story testified that payment of the CAMT means CEI South can no longer defer a portion of taxes to future periods and must therefore finance additional amounts to pay taxes in the current period. She said it may be necessary to increase borrowing to finance planned capital investments.

CEI South witness Jerasa testified that the cash outlay associated with CAMT presents a risk that will likely adversely impact CEI South's credit metric including Funds from Operations ("FFO")/debt if it is unable to recover the impact of the tax through rates. He said if credit ratings and metric deteriorate, CEI South's ability to invest in necessary projects may be impeded as incremental debt issuances may be otherwise limited based on lower credit metrics. Pet. Ex. 14 at 7-8.

Ms. Story testified that the CAMT has been calculated using CEI South jurisdictional amounts, with adjustments to financial statement income made for depreciation, pension expense, and federal income taxes. She said the CAMT credit carryforward is an asset and has been included in the cost-free capital calculation in this filing. When the minimum tax is paid, a CAMT credit is generated and can be carried forward indefinitely to offset the future regular income tax liabilities in periods where the regular federal income tax liability exceeds the CAMT liability. The CAMT credit cannot be carried back to previous taxable years. Ms. Story testified that on a going-forward basis, CAMT carryforwards would be addressed through CEI South's proposed TAR. She explained that the TAR would capture tax rider adjustments that have already been approved by the Commission in other dockets and would also be expanded to include the effects of the CAMT and passback of Indiana state EADIT. She stated there are two already approved tax riders that would move to the TAR. First, as a result of the Commission's investigation into the effects of the TCJA, CEI South is flowing back to customers federal EADIT from the TCJA through its TDSIC rider. This passback would continue outside of base rates but would instead be done through the TAR rather than the TDSIC. Second, PTCs realized from approved wind and solar projects are to be tracked through CEI South's CECA mechanism. This adjustment would move from the CECA to the TAR. As for the CAMT, Ms. Story testified CEI South's proposal is that between rate cases, a return on the CAMT carryforward calculated using CEI South's weighted average cost of capital determined in this rate case would be included in the TAR.

Ms. Story testified it is necessary to reflect the net impact of both the CAMT and PTCs from renewable projects. The CAMT provisions of the IRA were used to fund the extended and enhanced tax credits, so she stated that it is reasonable to include the impacts of both in this rider. Ms. Story testified that including both the PTCs and the incremental return on the CAMT payment in the TAR is necessary to capture the full impact of the IRA. A rider is necessary since annual results could vary significantly, making this a more reasonable approach than including these items in base rates. Similar to the process after TCJA was enacted, additional guidance is expected to clarify provisions of the IRA. A rider will allow CEI South to capture the impact of these rules as they become available.

Ms. Story described how IRA tracking would work under the TAR. She stated for PTCs, tracking should begin in 2025. If approved, CEI South will file a TAR in November 2025 that will include an estimate of the 2025 PTCs. For the CAMT carryforward, tracking should begin in 2026 after the test period. The second TAR filing in November 2026 will include the difference between the minimum tax 2026 carryforward estimated balance and the carryforward included in cost free capital in base rates, the result of which will be multiplied by the approved cost of capital from this proceeding. Additionally, it will include an estimate of the 2026 PTCs and a true-up of the 2025 estimated PTCs to actual. With additional guidance and proposed regulations still expected, it is most appropriate to commence tracking with this rate case, since it coincides with the IRA recently becoming law.

Ms. Story also addressed the ADIT and EADIT regulatory liability balances included in CEI South's cost of capital calculation. She said the federal EADIT resulting from the TCJA is currently being refunded in CEI South's TDSIC mechanism and CEI South is proposing to move these credits to the new TAR mechanism as described by witness Rice. Pet. Ex. 19 at 11. CEI South is also proposing to include state EADIT credits into the TAR mechanism. In addition, the credits for accelerated EADIT associated with the issuance of securitization bonds related to the retirement of A.B. Brown Units 1 and 2 will be moved into the proposed TAR. The refund of protected and unprotected EADIT has been forecasted through the end of the 2025 test period. The pro-forma balance of the EADIT regulatory liabilities, as well as the associated ADIT deferred tax assets, has been included as cost-free capital on Petitioner's Exhibit No. 20, Schedule D-5 sponsored by witness Jerasa. Pet. Ex. 15 at 18-19.

Ms. Story stated CEI South proposes to include the refund of the excess deferred state taxes in the TAR along with the federal EADIT. Like federal EADIT, the amortization of state EADIT would be outside base rates. Ms. Story testified that future changes to the federal EADIT balance would be addressed in the same fashion that such changes are addressed in the TDSIC mechanism presently. Future events such as IRS audit adjustments to CEI South's previously filed income tax returns, future IRS rulings and/or clarifications to the normalization rules, and changes in federal tax laws or rates could change the federal EADIT balance, as well as the split between protected and unprotected. She said these changes would be addressed in future TAR filings.

Mr. Rice stated the proposed TAR would include two tax adjustments that are already approved to be reflected in riders (the CECA and the TDSIC) and would reflect two additional adjustments, the CAMT and the amortization of Indiana state EADIT. CEI South's proposal is that beginning with the year following the test year, the creation of new CAMT carryforward will be reflected in the TAR by multiplying the new carryforward by CEI South's Weighted Average Cost of Capital from this rate case. Pet. Ex. 19 at 11. He explained CEI South is proposing that the TAR will reflect federal EADIT (currently passed back to customers through the TDSIC) and PTCs associated with the two renewable projects approved in Cause Nos. 45836 and 45847 (currently included in CEI South's annual CECA filings). CEI South proposes to include in the TAR the State EADIT (proposed to be amortized over five years). CEI South also proposes that, to the extent the proposed TAR is approved, the earnings test for purposes of Ind. Code § 8-1-2-42(d)(3) be updated to reflect the additional return from inclusion of the CAMT.

ii. <u>OUCC's Position</u>. Witness Stull testified that she does not oppose the proposed TAR, provided the current tax mechanisms will continue to charge or credit the same customer classes in the same manner as they are currently being implemented; however, she does oppose reflecting the CAMT in the rider. Pub. Ex. 6 at 4-5. She said CEI South's parent company, CenterPoint Energy, does not normally have AFSI of $1.0 billion or more, but rather is only currently subject to the corporate alternative minimum tax because of the impact of recent utility asset sales in other jurisdictions. Ms. Stull also asserted CEI South is "cherry picking" by only requesting to track the CAMT carryforward and not proposing to include all other items of ADIT in the TAR. She asserted that Indiana ratepayers should not bear the costs of CenterPoint Energy's non-Indiana financial transactions, including any additional taxes that may be due because of those transactions.

Ms. Stull argued that many unknowns accompany CEI South's proposal, including final determinations about whether CEI South's parent company will be subject to CAMT and whether the proposal would materially ameliorate the effects of CAMT to credit metrics or ratings. She recommended CEI South's proposal be denied; in the alternative, should the proposal be authorized, she recommended CEI South be required to track all tax-related components of cost-free capital.

iii. <u>CEI South's Rebuttal</u>. Ms. Story responded to Ms. Stull's conclusions regarding reflecting the CAMT in the tax rider, stating Ms. Stull has confused requirements regarding the applicability of the minimum tax and the calculation of the minimum tax. Ms. Story said Ms. Stull also failed to address the risk to cash flow and credit metrics described in Mr. Jerasa's testimony that is the basis for CEI South's proposal to reflect the CAMT in the proposed TAR. Pet. Ex. 15-R at 3. Ms. Story reiterated that the determination of whether CEI

South is an Applicable Corporation for purposes of the CAMT requires CEI South to use the consolidated group's (single employer's) AFSI. However, the calculation of CAMT attributable to CEI South does not include tax gains, losses, or other results of operations for jurisdictions CEI South does not operate in. CEI South is currently subject to the CAMT. CEI South's CAMT will result only from CEI South operations. CEI South will only owe CAMT if the tentative minimum tax exceeds the regular tax from stand-alone jurisdictional operations.

Ms. Story said CEI South's proposal is consistent with the long-established practice of permitting recovery of taxes associated with jurisdictional operations. She said like any prudent cost of providing electric service, the CAMT, consistent with all other federal, state, and local taxes incurred in the provision of electric service, is an appropriate cost of service expense. Ms. Story responded to Ms. Stull's argument that CEI South is "cherry picking" by seeking to track only the CAMT credit carryforward deferred tax asset and not deferred tax liability items, stating that Ms. Stull has failed to address the important issue of the increased risk to credit metrics and cash flow resulting from CAMT. CEI South witness Jerasa testified that S&P expects CenterPoint Energy, Inc. to be an annual cash taxpayer as a result of the CAMT, and its base case assumes annual cash tax payments of $150 million through at least 2026. S&P defines FFO as earnings before income tax, depreciation, and amortization ("EBITDA"), minus cash interest paid minus cash tax paid.[21] Therefore, the cash tax payments associated with the CAMT will directly reduce FFO and weaken FFO to Debt and other credit ratios, for both CenterPoint Energy, Inc. and its subsidiaries, including CEI South. Pet. Ex. 14-R at 6. He said cash taxes, including those arising from the CAMT, will lower FFO and weaken credit metrics, which could potentially impede future capital investments since CEI South will not be able to issue as much debt to maintain its current ratings. He stated the requested revenue amount included in CEI South's proposed tax rider will help mitigate the cash flow impact and absent the rider, there will be additional pressure on CEI South's financial integrity.

Ms. Story testified that Ms. Stull's proposal to include all deferred taxes in the TAR would both result in a mismatch to rate base, as well as violate the normalization provisions of the Internal Revenue Code ("IRC"). She noted the inconsistency in Ms. Stull's position, stating that to suggest that it is appropriate to include only the results of the IRA that result in a credit to customer rates and to exclude the cost associated with providing that benefit is asymmetrical. Ms. Story explained that the rate base mismatch resulting from Ms. Stull's suggested inclusion of deferred tax liability updates in the TAR would inappropriately reduce CEI South's return for items not yet being recovered. She further testified that Ms. Stull's proposal would be prohibited under the normalization rules of the IRS, specifically because inclusion of the deferred tax liabilities in the rider would violate the consistency rules of the normalization provisions. She explained that if a normalization violation occurs, CEI South would no longer be able to utilize accelerated depreciation in its federal income tax return. A normalization violation would mean a large reduction to cost-free capital (*i.e.*, reduction in deferred tax liabilities) and a significant increase in current taxes payable ultimately translating into less cost-free capital and higher borrowing costs to the utility.

[21] Pet. Ex. 14-R at 6 n.16, citing S&P Global Ratings, "Criteria: Corporate Methodology: Ratios and Adjustments" December 21, 2023, p. 3.

iv. **Settlement.** Section B.7.b of the Settlement Agreement withdraws CEI South's request to include future CAMT effects in its Tax Adjustment Rider. The Settlement Agreement acknowledges that the actual effects of the CAMT occurring by the beginning and end of the test year will be reflected in CEI South's capital structure for purposes of Settlement Phase 1 and Settlement Phase 2 rates. Settling Parties' Jt. Ex. 1 at Section B.7.b.

v. **Settlement Opposition.** OUCC witness Stull stated she accepted CEI South's proposal to create a TAR with the stipulation that the current tax mechanisms will continue to charge or credit the same customer classes in the same manner as they are currently being implemented. The Settlement Agreement does not, however, set forth how the currently approved tracker and passback mechanisms will continue being implemented. She stated the Settlement Agreement is not in the public interest if the passback mechanisms do not continue to be charged or credited to the same customer classes and in the same manner as they are currently charged or credited through the TDSIC and CECA trackers.

vi. **Settlement Rebuttal.** CEI South witness Rice stated CEI South is proposing to simply move existing schedules for the federal EADIT from TDSIC and proposed schedules related to the PTC from CECA to TAR. Pet. Ex. 19-SR, at 25. He explained that CEI South is not proposing to change the way the previously approved trackers were applied, but is proposing to consolidate them into a single, annual tracker. Additionally, CEI South has not proposed any changes to customer classes, so there is no change from this perspective. However, if the TAR is approved, CEI South witness Taylor recommended that federal EADIT that is currently being credited via the TDSIC tracker be allocated consistent with his recommended Rate Base allocations as shown in Attachment JDT-5, Schedule 4 - Rate Base Allocation. If the TAR is not approved, then CEI South would continue to credit the same customer classes in the same manner as shown in Attachment JDT-5, Schedule 2 - TDSIC Allocation.

vii. **Commission Discussion and Findings.** The Settlement Agreement eliminates the controversy over Petitioner's proposed TAR except with respect to the allocation across customer classes. The evidence of record demonstrates that Petitioner is not proposing to change the way the previously approved trackers were applied, except to provide consistency between the federal EADIT and the proposed rate base allocations. We find this proposal to be reasonable and consistent with the cost-causation principles discussed elsewhere in this Order. Accordingly, the Settlement Agreement's proposed resolution of issues related to the TAR is reasonable and should be approved.

J. **Additional Riders and Other Tariff Provisions.** Section B.7 of the Settlement Agreement describes proposed riders, including (1) the CPP Pilot, Rider ADR, and Green Energy Rider and (2) the TAR.

Section B.8 of the Settlement Agreement describes other tariff matters, including: (1) IC and IO Riders and (2) limitation of liability provision in the tariff.

In summary, the Settlement Agreement provides that CEI South's CPP Pilot, Rider ADR, and Green Energy Rider should be approved as proposed by CEI South, with CEI South further committing to provide all parties a copy of the contract with the demand response aggregator for Rider ADR after it has been signed. Settling Parties' Jt. Ex. 1 at Section B.7.a. The stipulations with respect to the proposed TAR are discussed in Section 0.I (CAMT, EADIT and TAR) of this Order.

With respect to the IC and IO Riders related to demand response, CEI South agrees to continue conversations with interested stakeholders. Settling Parties' Jt. Ex. 1 at Section B.8.a.

The Settlement Agreement also stipulates to the adoption and incorporation of IG witness Gorman's recommended changes to CEI South's limitation of liability provision in its tariff, with modifications as proposed by CEI South witness Rice on rebuttal. Settling Parties' Jt. Ex. 1 at Section B.8.b.

i. CEI South's Case-in-Chief.

1. CPP Pilot. CEI South is proposing a new time-of-use ("TOU") rate with a CPP Pilot program to allow for more efficient utilization of CEI South's system and provide a tool to help manage peak loads during hours of highest usage and provide customers with an opportunity to lower their bills. Pet. Ex. 19 at 12. Mr. Rice explained that this program may include multiple tiers of pricing with lower prices at off-peak times and higher prices at on-peak times. He stated this structure provides an economic incentive for customers to shift load from on- to off-peak hours. In addition, during times when usage is expected to be at its highest, the utility will communicate with customers that a critical peak event will occur on the following day. During the event, the cost of energy will be elevated above the typical on-peak period pricing to provide more incentive for customers to shift load. Mr. Rice testified this demand response-like component of the program, a CPP event, requires the customer to respond to the elevated price to be successful.

The proposed program will be implemented as a pilot program so that CEI South can better understand potential benefits of a full program and build effective communication tools to help ensure the future success of the program. The proposed CPP Pilot is estimated to cost approximately $1.75 million, consisting of an estimated $915,840 in capital expenditures and an estimated $838,762 to be expensed with the Year 2 evaluation included. The proposed pilot rate will be active for two years, after which CEI South proposes to evaluate impacts and processes associated with the CPP Pilot and lead a rate development study in year three of the Pilot. Mr. Rice testified that Cadmus helped to design the program and would perform the evaluation on the back end. If the CPP Pilot is approved, CEI South would file a request in a separate proceeding for approval of final TOU and CPP rates.

Mr. Rice described the eligibility requirements for the pilot. He said CEI South proposes to cap enrollment in the proposed CPP Pilot program to 500 residential customers to, "provide evaluators with a sufficient sample size for assessing the electricity demand impacts, participant experience, and pilot cost-effectiveness and to obtain useful insights for CEI South program administrators." To be eligible to participate in the CPP Pilot program, residential customers must have at least one year of automated meter data at the time of registration and must not be enrolled in an existing demand response program such as CEI South's Summer Cycler or Thermostat Load Control programs.

CEI South proposes a Rate RS-CPP that includes separate winter (defined as December through February) and summer (defined as March through November) rates. Proposed volumetric rates during the winter period would consist of a uniform volumetric energy charge of $0.16270 per kWh. Proposed volumetric rates during the summer period would consist of on-peak service of $0.28214 per kWh during weekdays from 1:00 p.m. to 7:00 p.m., and $0.07054 per kWh all other hours. Service during both winter and summer periods would also include a monthly service charge of $23.20 per customer and a volumetric charge during called CPP events of $0.56429 per kWh. Pet. Ex. 19 at 17. CEI South proposes to provide a one-time incentive of $75 for customers who enroll in the proposed program.

Mr. Rice described the goals for the CPP Pilot generally as "to help CEI South better assess the potential use cases and cost-effectiveness of TOU rates, like CPP, for managing residential electricity demand and the extent to which customers will embrace time-varying rates." Pet. Ex. 19 at 14. Specifically, he listed the following goals of the pilot program:

a. Gauge residential customer interest in time-varying pricing, determine expected participation rates, and gain an understanding of CEI South's likely marketing costs to enroll customers.

b. Learn the electricity demand and energy impacts of the TOU rate and CPP events, including the following:

    i. The average reduction in electricity demand per participant during the TOU rate on-peak period and the average increase in electricity demand per participant during the TOU rate off-peak period;

    ii. The average impact of CPP events on electricity demand per participant before, during, and after CPP events;

    iii. The impact of the CPP events on the participant's energy consumption;

    iv. The impact of the TOU rate on participant energy consumption; and

    v. To the extent possible given the small size of the pilot, whether the demand or energy impacts vary significantly by customer demographics, home type, or availability of different enabling technologies such as smart thermostats.

c. Learn the impacts of the TOU rates and CPP events on participant customer bills and whether the bill savings are commensurate with or exceed the cost to participants of attempting to shift their loads to lower priced periods.

d. Learn the avoided demand and energy costs and other non-energy benefits from the pilot as well as the likely cost-effectiveness of TOU rates with CPP.

Pet. Ex. 19 at 15.

2. **Green Energy Rider ("Rider GE").** CEI South witness Forshey described Petitioner's proposed Rider GE, which would allow Petitioner's large customers with a minimum annual usage of 5,000 MWh to purchase and claim RECs received for up to 85% of the MWh of energy generated by CEI South's renewable resources, whether from Petitioner's renewable energy projects or those renewable generation facilities with which Petitioner has a power purchase agreement ("PPA"). Pet. Ex. 17 at 5-6. All REC transactions would be conducted through the Midwest Renewable Energy Tracking System ("MRETS") marketplace. CEI South would use the historic REC price from the previous year to set the base price. CEI South witness Rice explained that each month, 15% of RECs generated would be sold into the MRETS market to establish the current market price. Pet. Ex. 19 at 26. The monthly amount billed to each Rider GE customer would be modified according to the adjusted market price and all Green Energy amount proceeds received will be credited back to all customers through the CECA rider.

3. **Rider ADR.** CEI South witness Rice explained that, as part of the IRP stakeholder process, CEI South committed to evaluating the use of a third-party demand response aggregator to help partner with customers in shifting load to off peak hours. Pet. Ex. 19 at 29. Mr. Rice and Mr. Forshey testified that Rider ADR will allow customers to partner with an aggregator to successfully lower load during MISO events. It is available to commercial and industrial customers to provide interruptible load and receive incentive payments directly from the program administrator to help offset electric costs. The tariff will be available for customers to participate in year-round or seasonally. Dispatches will be limited to four consecutive hours per event. Pet. Ex. 19 at 29; Pet. Ex. 17 at 21.

4. **Rider TLC.** Mr. Forshey described the proposed Thermostat Load Control Rider ("Rider TLC") to be marketed to customers using various marketing strategies and cross-promotion through other programs such as Residential Marketplace, in conjunction with the phase out of Rider Direct Load Control ("DLC"). Mr. Forshey testified this shift represents a shift in focus to achieving an increased level of demand response through smart thermostats versus switches. Pet. Ex. 17 at 22.

5. **Economic Development Rider ("Rider ED").** CEI South witness Forshey described CEI South's proposal to update its Rider ED to amend the current structure to be more intuitive and competitive with the economic development riders offered by other utilities in the State of Indiana. Pet. Ex. 17 at 10. Mr. Forshey testified that CEI South is proposing to eliminate the different level of incentives currently offered, thereby simplifying the applicability process while remaining firm on specific economic development requirements that are necessary to ensure current or prospective customers remain committed to the region and a long-term presence in Southwestern Indiana. These changes will also closely align CEI South's economic development incentives with those offered by CEI South's peers in the State of Indiana. Mr. Rice explained that CEI South is proposing to combine the two incentive levels currently in Rider ED and offer only one incentive level for projects at least 500 kVA/kW that result in capital investment at the customer's establishment of $1 million and the creation of ten new full-time jobs at the same location. Pet. Ex. 19 at 27. In addition, Mr. Rice explained CEI South is proposing to extend the credit from 24 months to 36 months and provide credit of up to $4.50 per kVA/kW.

6. <u>Interruptible Contract Rider ("Rider IC") and Interruptible Option Rider ("Rider IO")</u>. CEI South witness Rice described the proposed updates to Riders IC and IO, saying the tariffs were updated to reflect MISO's seasonal construct and expectations, which entails an associated increase in the number of interruptions the customer would be required to be available for annually. The amount of time per interruption was decreased to four consecutive hours per day. The amount of time to respond was increased from 10 minutes to 30 minutes. Metering requirements were added. Annual testing requirements and language around penalty for failure to interrupt were also included, consistent with MISO's BPM. Additionally, the size requirement to participate in the Rider IO was decreased to 100 kW from 250 kW. Pet. Ex. 19 at 28.

7. <u>MISO Demand Response Rider ("Rider DR")</u>. CEI South witness Rice testified that CEI South is proposing to remove the requirement that there be a minimum of 1 megawatt ("MW") load reduction to participate in this program and replace it with a threshold of 100 kW minimum, consistent with Emergency Demand Response, which is allowed within this tariff. Additionally, language was updated around communications processes to include proper equipment to receive MISO dispatch signals. Pet. Ex. 19 at 28.

CEI South witness Forshey described proposed updates to Rider DR to better align with current MISO market offerings. He explained that CEI South does not have a direct mechanism for customers with qualifying behind the meter generation ("BTMG") to participate in the MISO market as DRR Type 2 and potentially respond to market signals and collect revenues in the Day-Ahead and Real-Time MISO Markets. While customers with a BTMG could elect DRR Type I, it would not fully optimize the value of their resource in the MISO market. By allowing qualifying existing or prospective BTMG customers to participate in the MISO market as DRR Type 2, CEI South is providing those customers with an opportunity to supplement their revenue stream and support grid operations. Pet. Ex. 17 at 21.

8. <u>Updates to DSMA, RCRA, and MCRA</u>. Mr. Rice described certain proposed updates to the DSMA, RCRA and MCRA. He said all DSMA opt-out groups will be removed, since when new rates are put into place, CEI South will no longer collect lost revenue margin for programs prior to new rates being implemented. Mr. Rice said CEI South will file a compliance filing when new rates are implemented and remove approximately $12.1 million from DSMA rates for lost revenue margin. CEI South will begin calculating and recording lost revenues in 2026 to be recovered in the annual DSMA filing. CEI South will begin new opt-out groups at that time to the extent that other large customers opt out of DSM programs post new rates. Base amounts for DLC billing credits and DLC inspection and maintenance amounts have been adjusted to forecasted test year amounts. CEI South is also proposing that customers be allowed to opt back into EE programs at any time of the year. Pet. Ex. 19 at 30-31.

Mr. Rice described the updates to the RCRA to update base amounts for base level RCRA charges and revenues to reflect forecasted amounts. Additionally, CEI South is proposing to include Backup Capacity Generation Services variances generated from Rate BAMP in the RCRA. Pet. Ex. 19 at 31. The RCRA was also updated to reflect Petitioner's proposal, described by Mr. Rice and Mr. Bradford, to provide 100% of WPM sales margins to customers. Pet. Ex. 19 at 31; Pet. Ex. 7 at 18. Mr. Rice testified the move away from 50/50 sharing results in an estimated $7.1 million benefit to customers in 2025. Pet. Ex. 19 at 31.

The proposed updates to the MCRA reflect forecasted amounts for the base amounts for base level MISO charges and revenues. Pet. Ex. 19 at 31. Mr. Rice testified that CEI South is proposing to include Backup Transmission Services variances generated from Rate BAMP in the MCRA. Additionally, he said, CEI South added Real Time Schedule 49 and Real-Time Multi Value Project ("MVP") Distribution to the list of MISO charges.

9. Other Tariff Changes. Mr. Rice described various other proposed changes to CEI South's general terms and conditions of service, consisting of minor adjustments, clarifications, process updates and additions to align with the Indiana Administrative Code. Pet. Ex. 19 at 31-33.

ii. OUCC's Position.

1. CPP Pilot. OUCC witness Dismukes criticized the design of the CPP Pilot, saying it lacks clearly established goals and objectives, such that it will be difficult to measure future success or usefulness of the program. Pub. Ex. 12 at 58. He said the proposed CPP Pilot also lacks many consumer protection provisions that should be included in such a program. Dr. Dismukes opined that CEI South's proposed TOU-CPP goals are not well constructed to elicit meaningful insights to help CEI South or other stakeholders in designing effective time-variant rates. Specifically, he said CEI South's proposal: (1) co-mingles two separate rate structures into a single pilot program (both a proposed TOU rate structure and a CPP program), (2) fails to outline expected peak reduction or other benefits associated with the program, and (3) fails to outline in sufficient detail how the cost-effectiveness of the CPP pilot program will be evaluated in the future.

Dr. Dismukes also stated that CEI South did not estimate the expected benefits associated with and cost-effectiveness of the proposed CPP Pilot. Pub. Ex. 12 at 61. He further opined that CEI South has not indicated how it will evaluate future cost-effectiveness of the CPP Pilot and stated there is a need to establish a general outline for future evaluation criteria to ensure that the proposed pilot elicits results consistent with the goals of the pilot. Dr. Dismukes further opined that CEI South's CPP guidelines are insufficient, failing to address a multitude of aspects to the calling of CPP events which may lead to future customer confusion. He said that beyond limiting the future CPP events to 16 per year, the proposed CPP Pilot provides few restrictions on the frequency of potential called CPP events, such as the number of events during a given month or week, or even the potential for multiple consecutive days of called events. He also said CEI South explicitly leaves open the potential to call CPP events under the proposed CPP Pilot during adverse weather events, creating the potential for participating customers to receive significant electric charges for space heating and cooling requirements during oppressive weather situations. Dr. Dismukes stated that while the proposed CPP Pilot is intended to be revenue neutral, it is possible the final CPP Pilot could result in increased revenues for Petitioner over standard residential service rates based on the assumptions CEI South used about the timing of CPP events. He also expressed concern that CEI South does not propose an on-peak pricing period for winter use, which he said would send mixed messages to customers regarding when system peaks are expected to occur and how to change behavior to lessen electricity rate requirements. Dr. Dismukes also objected to CEI South's proposal to use the same consultant (Cadmus) that assisted CEI South in the design of the CPP Pilot in the eventual evaluation of the proposed pilot, saying this presents a potential conflict of interest as CEI South's evaluator of the CPP Pilot will have a vested interest in overstating benefits of a pilot they were intimately involved in designing.

Dr. Dismukes took issues with the way CEI South developed its proposed Rate RS-CPP and opined that the proposed Rate RS-CPP includes "significantly high on-peak and CPP rates for extended durations that could potentially lead to rate shock in the future." Pub. Ex. 12 at 67-69.

OUCC witness Paronish testified that CEI South's CPP Pilot proposal did not satisfy the GAO 2020-05 requirements. In addition to Dr. Dismukes's criticisms of the goals and design of the program, Ms. Paronish said the OUCC is unable to determine whether the CPP Pilot's design allows for "reasonable flexibility," as required by Part D of GAO 2020-05. Pub. Ex. 13 at 20. She also said CEI South did not provide an adequate timeline because it indicated a start date would "follow approval of the pilot."

2. Rider GE. OUCC witness Wright recommended CEI South be required to consider more than one REC marketplace when setting REC prices for the Rider GE program and that CEI South revise the language in the Rider GE and CECA tariffs to ensure all revenues from the Rider GE are properly credited to customers. Pub. Ex. 8 at 8-9. Mr. Wright recommended that, given the variability in REC marketplace prices and the connection between REC value and ratepayer affordability, CEI South should ensure it sells RECs for the maximum available value. He stated large customers should not receive reduced REC costs at the expense of reduced affordability for other ratepayers. He expressed concern that CEI South did not conduct an analysis comparing REC prices between available REC marketplaces and recommended CEI South compare prices between multiple available REC marketplaces and adjust for the maximum REC value in its monthly Rider GE bill adjustment. He opined that this adjustment would ensure ratepayers not enrolled in the program would still receive maximum benefit from the sale of RECs. He recommended amendments to the tariff to clearly define what constitutes "Green Energy Amount proceeds" to ensure all revenue generated by the program and sale of RECs is being passed on to customers through the CECA. He also recommended CEI South provide a sample formula of each monthly bill in the tariff and amend the language to clarify the total monthly variance that would be applied to each bill. He also recommended changes to the CECA tariff to define "qualified Clean Energy Investment" and to clearly include all revenue from the sale of RECs and all revenue otherwise generated by Rider GE.

3. Rider ADR. Mr. Wright recommended the Commission deny Rider ADR because CEI South failed to provide crucial details regarding the function and budget of the program. Pub. Ex. 8 at 8. Specifically, he said CEI South did not explain in testimony how the program would be funded, how MISO-qualified energy and demand reductions from the program would be credited, or how success or failure of the program would be evaluated. Pub. Ex. 8 at 6. He said that, although CEI South has already begun the aggregator selection process through its 2022 All-Source RFP, CEI South's testimony lacks key details on a contract with this aggregator or CEI South's relationship with it, including the amount being paid to the contractor, the demand reduction capacity goal of the contract, how contractor success would be evaluated, and what happens if the contractor fails to perform the expected demand. Mr. Wright testified that without these details, it is impossible to evaluate whether this program is in the best interest of ratepayers and so it should not be approved.

iii. **<u>CAC's Position</u>.** Regarding CEI South's proposed demand response items, CAC witness Inskeep stated the CAC recommends the following revisions to the proposed tariffs and pilot:

1. Enhance flexibility and expand demand response offerings.
2. Develop a robust customer recruitment plan.
3. Simplify interruptible tariffs.
4. Expand residential demand response tariff options.
5. Expand residential CPP pilot options.
6. Conduct additional pilot rate analysis.
7. Aim for rapid pilot-to-program evolution.

CAC Ex. 2 at 70.

Mr. Inskeep opined that, by implementing these recommendations, CEI South could enhance its demand response initiatives, ensuring they are both customer-friendly and aligned with broader energy management goals. He requested that CEI South use its DSM Oversight Board ("OSB") to continue discussion and collaboration to refine these proposals and plan marketing, education, and other components that will be key to the success of these programs. Accordingly, he recommended that the Commission approve CenterPoint's demand response riders and programs with these revisions.

iv. **<u>Industrial Group's Position</u>.** IG witness Gorman recommended a change to CEI South's current tariff provision limiting its liability for service interruptions. He said the provision as written is unreasonably broad and would purport to eliminate any and all liability for damages caused by service interruptions, regardless of the degree of fault on the part of CEI South. IG Ex. 1 at 137-138. He said CEI South's provision is much broader than the limitation of liability tariffs of the other four investor-owned electric utilities in Indiana. He recommended changes to carve out of the limitation of liability CEI South's own willful default or negligence.

v. **<u>CEI South's Rebuttal</u>.**

1. **<u>CPP Pilot</u>.** Mr. Rice outlined how the CPP pilot proposal satisfies the six requirements set forth in GAO 2020-05. Pet. Ex. 19-R at 28-29. Mr. Rice summarized the conceptual evaluation criteria, both the explicit and implied mentioned in his direct testimony, in his Table MAR-R9. He said CEI South will continue to work with Cadmus to finalize evaluation criteria should the pilot be approved. Mr. Rice testified that CEI South chose a path that delivers maximum flexibility. He said the pilot is a small-scale, short-term experimental trial intended to test and learn how a large-scale program might work in practice and provide valuable data that can be utilized in CEI South's future evaluation of cost/benefits in its 2028 IRP. Pet. Ex. 19-R at 32. He opined that CEI South's approach of not including the costs of a fully developed, large scale program within its case in chief, *i.e.*, full cost of finalizing the program design and EM&V measures, fully drafting a contract for pilot participants, developing marketing and customer educational materials, and fully developing the rate, not only delivers maximum flexibility because there is opportunity to evaluate and modify the program based on pilot data and stakeholder feedback but also benefits customers by saving money by only including costs related to implementing a pilot, and not a fully developed program, in this Cause.

With respect to the timeline for the CPP Pilot, Mr. Rice testified that, following an Order approving the pilot program, CEI South will kick off the rate development study; begin development of educational and marketing materials; begin the IT and billing infrastructure setup; and will work with Cadmus to finalize design work. CEI South plans to file for final rates in a separate docketed proceeding in Q2 2025 to have final rates approved by the end of 2025. Throughout 2025, IT will work on billing and infrastructure setup and will finalize that work by the end of 2025. By early 2026, CEI South plans to begin recruitment and train customer service and billing agents on the pilot program to equip them with the tools needed to fully support customers when the pilot begins. CEI South is targeting Q2 2026 to begin the pilot. CEI South will implement the pilot and begin capturing data for Cadmus' evaluation, with final results for year one by Q2 2027. Mr. Rice stated that if needed to gather sufficient data, CEI South may extend the pilot for up to one year, with a final evaluation to be completed by Q2 2028, which will provide CEI South sufficient time to incorporate results into the 2028 IRP. Mr. Rice stated CEI South plans to meet with interested stakeholders to discuss progress and solicit feedback about every six months until the 2028 IRP stakeholder process begins; from that point forward, any updates/feedback on CPP will come through cost benefit testing in the IRP.

Mr. Rice explained that the pilot is designed to include both TOU and CPP pricing elements in one rate structure because each pricing element addresses a different source of variation in demand. He said TOU pricing is meant to reflect prevailing changes in demand across hours of the day (*e.g.*, the normal summertime afternoon peak) and CPP pricing is intended to address changes in demand occurring due to emergency events (*e.g.*, a heat wave). He explained a rate structure that includes both pricing elements is expected to be more effective than either pricing element in isolation because it creates incentives for conservation in response to both sources of variation in demand. For this reason, he stated CEI South is most interested in deploying a TOU-CPP pricing structure. With respect to evaluation, he said the most straightforward way to evaluate a TOU-CPP rate structure is to directly include the TOU-CPP rate structure in the pilot.

Mr. Rice rebutted the notion that CEI South did not include testimony regarding why the CPP Pilot is in the public interest, citing to his direct testimony discussion of the short-term and long-term benefits of the program. Pet. Ex. 19-R at 34. He said if this tool proves to be effective, CEI South may utilize a CPP program to help offset the need for new generating resources.

Mr. Rice corrected an inaccuracy in Dr. Dismukes's description of how the customers will be notified of a called CPP event. He said there is a distinction drawn within the TOU-CPP Indicative Tariff between a CPP event and the potential to use the program for a system emergency, but Dr. Dismukes lumps these two different situations into one. Pet. Ex. 19-R at 35.

Mr. Rice testified that CEI South will develop educational materials to help customers understand the TOU-CPP program and potential risk of higher bills. He said CEI South has included $30,000 in its cost estimate to develop such educational materials. Pet. Ex. 19-R at 36-37. Mr. Rice quantified what a CPP event may cost a customer, which, based on the maximum annual number of MISO events in a year (16) would equate to about $80 for event hours for an average residential customer using 799 kWh per month. He reiterated that customers will be paid

$75 to participate in the pilot. Additionally, he noted this is a voluntary program, and customers may voluntarily leave the program if they have a bad experience.

Mr. Rice explained that CEI South did not propose a TOU rate during the winter because peak hours in the winter are much less predictable than summer peaks and may occur at different times of the day, depending on when cold fronts move in and settle over the area. The TOU portion of this rate is not applicable in the winter, as it would be much harder to educate customers to modify their consumption behavior to set hours of the day. He said while not proposing a TOU rate during the winter, CEI South does want to test the CPP portion of the rate in the winter months to evaluate its ability to offer the CPP program into the MISO market as a LMR during the winter season.

Mr. Forshey explained the benefits of having the same vendor both design and evaluate the CPP Pilot, including lower costs to be incurred as the vendor would not need to spend time learning and understanding the pilot design and expected outcomes. Pet. Ex. 17-R at 6. He said using the same vendor, instead of two vendors, will also streamline evaluation of the pilot by administering customer surveys in a timelier fashion, such as a few days after a critical peak event is called, offering advantages in higher customer response rates as well as better recall. Mr. Forshey testified that a company that both designed and then evaluates the pilot would not need to hit pause to survey the utility's staff on how it developed the program design before administering surveys, etc. Moreover, he stated the ongoing engagement of one vendor performing the evaluation will accelerate when final evaluation results will be available to inform program design and implementation recommendations for the second year of the pilot. He said the complex nature of pricing pilots using hourly time of use information demonstrates the need for vendors to understand CEI South's customer demographics and CEI South's implementation of the pilot in terms of education of time of use rates, informing customers of peak events, and data integrity to measure results. As a result of this complexity, Mr. Forshey testified that adding a vendor for design and another vendor for evaluation will increase costs, lengthen the Evaluation Measurement and Verification ("EM&V") reporting, and potentially increase the time for design changes identified in the final EM&V report to be implemented by CEI South.

2. <u>Rider GE</u>. In response to OUCC witness Wright's recommendations, CEI South witness Rice explained that CEI South is currently selling RECs for what the market will bear. CEI South's renewable resources are all located within MISO, making M-RETs the logical choice for registering these resources. Mr. Rice testified that CEI South believes it is better to offer these RECs to its customers to meet their sustainability goals than to others with no connection to the community. Pet. Ex. 19-R at 23. Mr. Rice reiterated points raised by witness Forshey, that eligible customers for Rider GE are CEI South's largest customers and contribute to the fixed cost recovery of CEI South's system. Mr. Rice said Rider GE helps ensure they can meet their sustainability goals without relocating, choosing to expand elsewhere, or avoiding some fixed cost recovery of the system by installing behind the meter generation. He stated all these possibilities would have a negative impact on affordability for CEI South's customers that are not participating in the program. Mr. Rice also noted the administrative burden and increased cost that would be imposed as a result of the OUCC's recommendation. He said CEI South would be required to monitor "multiple available REC marketplaces," and compile data. He further noted it is not clear what markets the OUCC would like CEI South to benchmark against or if the data is readily available without a fee. Mr. Rice gave an example of CEI South's recent sale of RECs from Troy Solar to buyers in Ohio, which is the example market Mr. Wright pointed to in his testimony. He explained that to have the opportunity for a higher price, resources would likely need to be registered with other states bound by a Renewable Portfolio Standard, according to their requirements. Mr. Rice cautioned that this approach will likely increase volatility of REC pricing, which may drive requests by Rider GE customers to better understand how the benchmark is set, provide customer reconciliations with explanations of drivers, or something that will be almost impossible, forecasting a market that does not exist.

In response to Mr. Wright's suggestion to update the tariff language to better define "all Green Energy amount proceeds," Mr. Rice testified that the tariff was updated to reflect that Green Energy Amount proceeds are REC revenues from participating Rider GE customers, net of any necessary fees incurred from M-RETS. Mr. Rice disagreed with Mr. Wright's recommendation to amend the CECA tariff if Rider GE is approved. He said the current CECA tariff does not discuss the treatment of RECs. He explained that, should the Rider GE be approved by the Commission, CEI South will propose updated schedules within the next CECA filing following an order in this case, which will clearly break out any REC revenues, net of necessary costs, associated with Rider GE.

3. <u>Rider ADR</u>. Mr. Rice responded to Mr. Wright's criticisms of the proposed Rider ADR. He noted that the OUCC participated in the IRP stakeholder process, was engaged in multiple tech-to-tech calls, and reviewed CEI South's IRP, but did not question the need for the ADR resource during the IRP stakeholder process. Pet. Ex. 19-R at 24-25. Mr. Rice recited the portions of his direct testimony and Mr. Forshey's direct testimony that provided details on the program. He explained that because CEI South does not have an approved program, it has not entered into contract negotiations with a DR aggregator. He did say that CEI South routinely contracts for capacity and recovers costs via the RCRA and this would be no different in that respect. Mr. Rice opined that DR aggregation is a better solution to CEI South's capacity needs in that it will provide a potential new revenue stream to help offset rates paid by CEI South customers, helping with affordability, improving customer satisfaction, and providing reliability benefits to the local system. He said there would be less risk in working with a DR aggregator than posed by the current industrial DR tariffs as the DR aggregator would be a MISO market participant, held to the same standards and evaluation criteria for Load Modifying Resources ("LMR") as any other industrial customer participating in CEI South's applicable DR tariff. *Id.* Mr. Rice testified that DR aggregation can save customers money in the short and long-term, helping with affordability.

Mr. Forshey testified that if Rider ADR is approved, the contract with the DR Aggregator will be aligned with MISO's Tariff and Business Practices Manuals ("BPMs") to ensure CEI South receives the appropriate capacity accreditation with MISO. For example, the DR Aggregator selected would be the MISO participant and would bear the risk of penalties from MISO for non-performance, so CEI South customers would not bear that risk. CEI South would also ensure other appropriate customer protections are established within any contractual arrangement with a DR Aggregator to make sure the risk remains with the DR Aggregator and not CEI South's customers. Similarly, the DR Aggregator and participating aggregated DR customers must meet the requirements set by MISO for LMRs. Mr. Forshey testified that this requirement ensures that CEI South can register these resources with MISO and receive the appropriate capacity accreditation. As discussed in Rider ADR, the DR Aggregator or "Program Administrator" would be responsible for communicating with participating customers prior to and during a load reduction event, for providing incentive payments to participating customers, and for delivering a post-event performance report to CEI South based on the results provided by the metering and control technologies put in place to monitor participating customers. Pet. Ex. 17-R at 3.

4. **Limitation of Liability Provision.** On rebuttal, Mr. Rice accepted Mr. Gorman's proposal to change the limitation of liability provision but suggested minor modifications to the language Mr. Gorman recommended. Specifically, CEI South proposed to include the phrase "willful or wanton misconduct or gross negligence" in the carveout recommended by Mr. Gorman to more accurately address the issue Mr. Gorman raised. Pet. Ex. 19-R at 48.

vi. **Settlement.** In Section B.7 of the Settlement Agreement, the Settling Parties stipulate and agree that CEI South's proposed CPP Pilot; ADR; and the Rider GE be approved as proposed by CEI South. Pet. Ex. 19-S at 14.

1. **CPP Pilot.** Mr. Rice reiterated the purpose and benefits of the proposed CPP Pilot. He noted that this program is not the first of its kind in Indiana, as Indiana Michigan Power ("I&M") has an approved CPP tariff, which CEI South utilized in developing the proposed pilot.

2. **Rider ADR.** Mr. Rice noted that Section B.7 of the Settlement Agreement states that CEI South agreed to provide all parties to this Cause a copy of the contract with the DR aggregator after it has been signed. This will allow the parties to see the protections alluded to in Mr. Forshey's rebuttal testimony. Pet. Ex. 19-S at 16. As discussed in Section 0.G (Pro Forma Revenues and Expenses), the Settling Parties, in Section B.5 of the Settlement Agreement, stipulated and agreed to remove the $725,000 from base rates, eliminating the controversy over the inclusion of that amount in base rates.

3. **Rider GE.** Mr. Rice reiterated that CEI South will sell RECs for what the market will bear, and creating an index creates an unreasonable administrative burden. He said Rider GE helps ensure eligible customers can meet their sustainability goals without relocating, choosing to expand elsewhere, or avoiding some fixed cost recovery of the system by installing behind the meter generation. All these possibilities would have a negative impact on affordability for our customers that are not participating in the program. Pet. Ex. 19-S at 16.

4. **Rider IC and IO.** Mr. Rice explained that in the Settlement, CEI South agreed to continue conversations with interested stakeholders regarding changes to its IC and IO Riders related to Demand Response. He noted that CAC witness Inskeep encouraged CEI South to continue to collaborate with CAC and the OUCC on these topics and continue to work with the DSM OSB to further refine and ensure the success of the programs. The Settling Parties stipulated and agreed to this term to continue to work with those interested parties on changes to its Rider IC or Rider IO. Pet. Ex. 19-S at 17.

In Section B.8.b of the Settlement Agreement, CEI South agreed to adopt and incorporate the changes to its limitation of liability provision in its tariff as recommended by IG witness Gorman and modified by CEI South witness Rice on rebuttal. Pet. Ex. 19-S at 17.

vii. Settlement Opposition. OUCC witness Wright testified that the Settlement Agreement did not address the issues he raised and nothing in CEI South's rebuttal or the Settlement or testimony supporting the settlement caused him to change his position or recommendations. He still recommends denial of the proposed Rider ADR due to lack of basic information provided on the budget and functioning of the program. He still recommends Rider GE consider multiple REC marketplaces when setting REC prices for the program to maximize the benefit of the RECs for all rate classes. Pub. Ex. 8-S at 2-5. Mr. Wright stated the OUCC disagrees with Mr. Rice's assertion that large industrial customers will relocate or build behind-the-meter generation. He said the assertion that large industrial customers would base this decision solely on the availability of low-cost RECs through the Rider GE is speculation.

OUCC witness Dismukes testified that the Settlement Agreement did not address his concerns regarding the CPP Pilot. Pub. Ex. 12-S at 4-5. He stated the few evaluation criteria CEI South has put forward associated with the CPP Pilot are lacking the specifics required for such a pilot. He said CEI South has not established any marker for potential load shifting it would realistically seek to accomplish through the proposed pilot program, has not established a prior baseline for estimated energy savings associated with the CPP Pilot, and has not established either a baseline bill savings estimate to judge performance from or, importantly, establish the level of negative bill impacts (*i.e.* increased bills due to the pilot) CEI South would find unacceptable.

Ms. Paronish testified she continues to have concerns with the CPP Pilot and that it is irrelevant whether the OUCC or other stakeholders commented on this issue during the IRP process. Furthermore, she opined it is extremely prejudicial and inappropriate for Petitioner to criticize the OUCC for not then raising concerns with the program now presented for approval. She emphasized that an IRP is a non-binding statement of general intention by a utility, and not a docketed proceeding in which a utility seeks specific relief. Pub. Ex. 13-S at 13. She compared DSM programs and the EM&V process to the proposed CPP Pilot, noting the EM&V vendor is independent of the utility and the vendor the DSM OSB selected to design programs. In the case of the CPP Pilot, there is no OSB, and there is no independence from the utility. She likened this to "the fox watching the henhouse." She also noted that during the DSM EM&V process the OUCC and other OSB members participate in regularly scheduled calls with the EM&V vendor to understand what is transpiring and to discuss issues. Also, the OUCC and other OSB members have the opportunity to look at the draft EM&V report prior to finalizing and filing with the Commission. She recommended that if the Commission approves this program, the Commission direct CEI South to choose two separate vendors – one to design its program and one to perform EM&V. However, if the Commission allows CEI South to use the same vendor to both design and perform EM&V on the CPP Pilot, Ms. Paronish stated an OSB-like process should be required. She said this would enable the OUCC and interested intervenors to participate and scrutinize the EM&V report prior to it being filed with the Commission. Pub. Ex. 13-S at 17.

Ms. Paronish recommended that if the Commission approves this program, CEI South should be required to provide a written plan explaining and committing to how the Commission, the OUCC, and intervenors can be involved throughout the CPP Pilot. Pub. Ex. 13-S at 18.

CAC witness Inskeep took issue with Mr. Rice's characterization of his testimony as "commend[ing] CEI South for moving forward with proposals such as the CPP Pilot," saying this omits that Mr. Inskeep also requested "that CEI South use the DSM OSB to continue discussion and collaboration to refine these proposals and plan marketing, education, and other components that will be key to the success of these programs." CAC Ex. 6 at 20 citing CAC Ex. 2 at 69. He had proposed revisions regarding enhancing flexibility and expanding demand response offerings, developing a customer recruitment plan, expanding residential customer demand response tariff options, and expanding the CPP Pilot (*e.g.*, pilot time of use rates and peak time rebate options). Mr. Inskeep stated that CEI South largely ignored these recommendations, while the Settlement Agreement approves CEI South's proposals without incorporating most of his recommendations, with the exception that additional discussions will be held regarding interruptible tariff changes. He expressed concern that CEI South is moving forward with its demand response proposals without incorporating most of the constructive feedback provided by CAC to enhance these offerings and ensure their success for both the utility and its customers.

viii. <u>Settlement Rebuttal</u>.

1. <u>CPP Pilot</u>. Mr. Rice responded to Dr. Dismukes's repeated concerns over the CPP Pilot, expressing that it appeared Dr. Dismukes does not understand how the results from the CPP Pilot will be incorporated into an upcoming IRP. Pet. Ex. 19-SR at 22. Mr. Rice explained that the full evaluation of CPP is not limited to the pilot; it includes pre-evaluation with expected demand savings that were included in the 2022/2023 IRP. Once load shifting estimates and its demand response potential are evaluated and refined with results from the CPP Pilot, CEI South will utilize the CPP Pilot results to further evaluate CPP in the 2028 IRP as a resource option. Mr. Rice said the requirement of participants to have at least one year of automated meter data at the current premises is precisely for the purpose of establishing a baseline for estimated energy savings that Dr. Dismukes claimed was lacking. Mr. Rice said there is no absolute threshold for comparing bill savings relative to perceived benefits, which is better evaluated through customer engagement surveys, and the CPP Pilot will instead evaluate in absolute terms how well or poorly each customer fared. He said customer engagement surveys will also be used.

2. <u>Rider GE</u>. In Attachment MAR-SR2, Mr. Rice addresses Mr. Wright's opposition to Rider GE. He reiterates that the issue is not the ability to sell to multiple marketplaces but that once a resource is committed, it is a long process to withdraw and register in another market; CEI South cannot simply sell to one market one month and another the next. Also, time and effort is needed to understand the pros and cons of each market. Once CEI South sells outside of M-RETS the industrials cannot purchase them. Pet. Ex. 19-SR, Attachment MAR-SR2 at 2.

3. <u>Rider ADR</u>. In Attachment MAR-SR2, Mr. Rice responds to Mr. Wright's arguments in opposition to the Settlement Agreement with respect to Rider ADR, which focus more on his argument that the information provided in rebuttal should have been contained in Petitioner's case-in-chief. Mr. Rice points out the time that elapsed between rebuttal and settlement opposition testimony, noting there was ample time for a substantive response, which Mr. Wright did not provide. Pet. Ex. 19-SR, Attachment MAR-SR2 at 2.

ix. Commission Discussion and Findings.

1. CPP Pilot. The record reflects that the CPP Pilot is designed to benefit customers by offering a tool to help keep electricity service affordable in the near- and long-term. The evidence shows a customer enrolled in the pilot that consumes a significant portion of their energy in off-peak hours is likely to realize bill savings. In addition to the benefit to customers, if proven effective, the tool could be used by CEI South to help offset the need for new generating resources. This tariff is not the first of its kind in Indiana and no party has denied the value of time varying rates. We find this program is in the public interest and should be approved, as incorporated into the Settlement Agreement.

2. Rider GE. CEI South proposed Green Energy Rider to provide CEI South's largest customers the ability to acquire locally sourced REC to help those customers meet individual sustainability goals. Eligible customers for Rider GE are CEI South's largest customers and contribute to the fixed cost recovery of CEI South's system. As for the OUCC's recommendation to require CEI South to price RECs based on multiple unidentified REC markets, we are not persuaded any potential benefit would outweigh the cost of such a requirement. We find Rider GE is in the public interest as is the Settlement Agreement provision adopting it as proposed in CEI South's case-in-chief.

3. Rider ADR. CEI South proposed Rider ADR, consistent with its IRP preferred portfolio to provide up to 25 MW of demand response. The tariff will allow for CEI South customers to partner with an aggregator for a customized solution to help them successfully lower load when needed. The record reflects how Demand Response Aggregation can save customers money in the short- and long-term, providing customers with a potential revenue stream to help offset CEI South bills, helping to avoid energy purchases when energy prices are highest and over the long-term helping avoid or delay the need to build new power plants. Pet. Ex. 19-R at 28. CEI South's Rider ADR is in the public interest as is the Settlement Agreement provision adopting it as proposed in CEI South's case-in-chief.

We find Petitioner's other proposed changes to its riders and tariffs were not disputed and should be approved as proposed in CEI South's case-in-chief.

K. ARP for Remote Disconnection. Section B.9 of the Settlement Agreement addresses Petitioner's proposed ARP for remote disconnection.

i. CEI South's Case-In-Chief. CEI South witness Folz presented CEI South's request for approval of an ARP to implement remote disconnect for non-payment process through a waiver of 170 IAC 4-1-16(f) and explained how the ARP satisfies the requirements of Ind. Code ch. 8-1-2.5 (the "Alternative Utility Regulation Act" or "AUR Statute"). She explained that CEI South is specifically seeking a variance from the requirement to be physically present on the customer's premise for the disconnect for non-payment. Pet. Ex. 5 at 11. She explained the communications with customers and information to be included in notices, which generally satisfy 170 IAC 4-1-16(f). Ms. Folz stated that medical need customers and life support customers will be exempt from this process and will continue to have field personnel on premise. She also stated that, if at the time of the disconnect for non-payment, CEI South is notified that a customer is applying for, or received funds for, LIHEAP during that current LIHEAP season, CEI South would not process the disconnect for non-payment during that LIHEAP season.

Ms. Folz described the benefits to customers from CEI South's proposed process, noting that customers will have access to a customer service representative who has expertise responding to, and handling, calls related to non-payment. She said CEI South's proposed actions under the ARP eliminate an unnecessary step, allowing customers to more quickly, and conveniently, take action to resolve the disconnection of service. Ms. Folz noted that the Commission has granted waivers from 170 IAC 4-1-16(f) to other Indiana utilities – including Duke Energy Indiana, I&M, and AES Indiana – to allow for remote disconnection for non-payment. Ms. Folz testified that remotely performing disconnect for non-payment orders will further reduce safety risks, improve work efficiencies, and significantly reduce the reconnect charge for remote reconnects. She then described the notification process CEI South plans to utilize for performing remote disconnects as well as the notification process CEI South intends to use to notify all customers that may be subject to remote disconnection for non-payment prior to implementing the process. Ms. Folz indicated that if approved, CEI South would begin remote disconnects for non-payment once all system changes and communications have been addressed, using a phased approach.

ii. **<u>OUCC's Position</u>.** OUCC witness Paronish indicated that the OUCC does not oppose CEI South's request for waiver of 170 IAC 4-1-16(f) and recognized the potential customer benefit of CEI South's proposal, subject to certain recommendations for implementation of the ARP. Pub. Ex. 13, at 8. She stated that, in addition to medical need and life support customers receiving an in-person field visit for disconnection due to non-payment, the residential customers that have non-AMI meters should also receive an in-person field visit. Ms. Paronish suggested there could be "tens of thousands of customers that CEI South cannot contact if it initiates remote disconnects." Ms. Paronish recommended that "the company begin a proactive campaign to collect customer contact information at least three months before implementing the remote disconnection program and continue each month until the program is implemented." Ms. Paronish proposed specific language for communicating changes to CEI South's customers. She also proposed specific communication methods.

iii. **<u>CAC's Position</u>.** CAC witness Inskeep recommended the Commission deny CEI South's proposal to implement remote disconnection for nonpayment. He also recommended the Commission consider implementing a 12-month residential disconnection moratorium to allow time for CEI South to establish and implement additional affordability measures, including his proposed Affordable Power Rider. CAC Ex. 2 at 10. Mr. Inskeep contended the ARP for remote disconnects would make it easier for the utility to disconnect ratepayers without adequately informing them through an on-premises visit. He asserted that consumers may miss notices sent by a utility via phone call, text message, or email informing them of a bill delinquency and potential disconnection. An in-person visit is a critical backstop protection that can reach vulnerable customers who might otherwise miss notification. He referred to a "rising number of disconnections and increasing disconnection rate." *Id.* at 76.

Mr. Inskeep also contended CEI South's ARP is not consistent with Ind. Code ch. 8-1-2.5 requirements. He opined that while advancements in technology in the form of AMI has made remote disconnection technologically possible and facilitated additional communication channels between the utility and some of its ratepayers, it does not mean that the need for an on-premises visit has been rendered unnecessary from a consumer protection perspective. He testified that CEI South's proposed ARP would be detrimental to its customers who would experience reduced protections compared to those who are currently afforded the on-premises visit prior to disconnection and asserted it would harm the utility by eroding its reputation and goodwill in the community. Mr. Inskeep stated CEI South's ARP would not promote energy utility efficiency because "disconnecting customers from electricity service is not necessary for – and indeed, is the very antithesis of – the provision of safe and reliable electricity service." *Id.* at 78. Finally, Mr. Inskeep argued that the exercise of Commission jurisdiction does not inhibit Petitioner from competing with other providers of functionally similar services or equipment, because Petitioner is a monopoly utility and the only entity legally able to sell electricity to retail customers within its service area and "is not in competition with Duke Energy Indiana and Indiana Michigan Power to serve customers in its service area." *Id.*

iv. <u>CEI South Rebuttal</u>. CEI South witness Folz responded to the concerns of Ms. Paronish and Mr. Inskeep with respect to the ARP for remote disconnections. CEI South accepted many of OUCC witness Paronish's recommendations, with slight modifications. Ms. Folz explained that the customers referenced by witness Paronish do not have an AMI meter installed and therefore, CEI South does not currently have the ability to perform the disconnect remotely, so until the meter is upgraded, these customers will continue to receive in-person visits prior to disconnecting electric service to their premises, if the situation ever arises. Pet. Ex. 5-R at 4. Ms. Folz provided data indicating that there are only 2,379 customers without a phone number in CEI South's system, so approximately 98.5% of the 134,972 eligible customers have phone numbers in the system. In addition, she stated CEI South has many methods of contacting its customers, and CEI South's remote disconnection for non-payment proposal includes the utilization of multiple communication channels to contact customers, including the disconnect bill itself through mail or email (depending on customer preference), outbound phone calls, text, and email prior to the disconnect. Ms. Folz testified that CEI South commits to proactively soliciting customer contact information through a communication campaign at least three months before implementing the remote disconnection program and to continue each month until the program is implemented. Communication methods include mailed bill messaging and emailed bill messaging (for those signed up for electronic billing). With respect to Ms. Paronish's specific language for customers communications about the change, Ms. Folz testified that CEI South agrees in principle with the proposed language, but noted it may require slight modifications, for example the CEI South name (from a branding standpoint), additional contact methods (including by customer bill and phone), and more clear steps to access the customer's online account. She stated CEI South will commit to providing the OUCC and other intervenors a copy of CEI South's language.

Ms. Folz indicated CEI South accepts the proposed methods with the addition of methods typically used by CEI South to communicate with customers (*i.e.*, social media and news release). She added that, in conjunction with CEI South's EIP, CEI South will require customers to update their online account passwords during the summer of 2024. With that, CEI South will prompt customers to update their contact information. She confirmed CEI South will commit to the following communication methods:

1. CEI South Website

    - Promotional popup/notification on home page.

    - Promotional popup/notification on customer account dashboard page.

    - Prompt for customers to update their contact information.

2. An alert to go to CEI South's website, in red font, on the customer's bill.

3. A bill insert regarding the process change and need for accurate contact information.

4. An auto dial notification message regarding the process change and need for accurate contact information.

5. A text notification message regarding the process change and need for accurate contact information.

6. An email notification to customers with e-mail addresses on file with CEI South notifying customers of the process changes, using the modified proposed language.

7. CEI South will use Nextdoor, Facebook, and X to provide information on this process change and the request for accurate contact information.

8. CEI South will use a news release to provide information on this process change and the request for accurate contact information.

Ms. Folz testified that Mr. Inskeep's recommendation to impose a moratorium on CEI South for disconnections is contrary to the Commission rules (170 IAC 4-1-16) that allow for disconnection due to non-payment under certain conditions. Aside from violating the Commission's rules, Ms. Folz asserted that imposing a mandatory, 12-month delay in disconnections due to non-payment would counteract affordability efforts. She explained that timely disconnections prevent customers from obtaining service without paying. The longer the amount of time of receiving service without paying for that service, the larger the customer's arrears payment will become. Pet. Ex. 5-R at 9. Contrary to Mr. Inskeep's assertion that the proposal would make it easier for utilities to disconnect residential ratepayers without adequate notice through an on-premise visit, Ms. Folz testified that CEI South's proposal actually will enhance and streamline the communication process, making it easier for customers to prevent a disconnection for non-payment. CEI South is proposing a process change for disconnects due to non-payment that will increase communication, which ideally will prompt quick action from CEI South's customers to either pay their bill, request payment assistance, or get low-income support, ultimately reducing disconnections due to non-payment. Ms. Folz also provided evidence of CEI South's compliance with each of the four criteria set forth in the AUR Statute.

v. <u>Settlement</u>. In his settlement testimony, CEI South witness Rice testified that, given neither the CAC nor OUCC joined the Settlement Agreement, the Settling Parties stipulated and agreed in Section B.9 that the approval of CEI South's request for approval of the ARP, as modified pursuant to Section B.9, will be left to the Commission's discretion and determination. Section B.9 further provides that CEI South agrees to incorporate certain customer protections as set forth in Section B.10 of the Settlement Agreement. Pet. Ex. 19-S at 18.

vi. <u>Settlement Opposition</u>. OUCC witness Paronish provided testimony taking issues with certain positions taken in CEI South's rebuttal that she said did not fully transfer to the Settlement Agreement, noting an inconsistency between the rebuttal position incorporated into Section B.9 of the Settlement Agreement and Section B.10.d.i.1 of the Settlement Agreement, which states: "CEI South will provide at least thirty days advance notice to customers before implementing the remote disconnection/reconnection proposal." Pub. Ex. 13-S at 4-5. She continued to recommend there be at least a three-month communication campaign in connection with the remote disconnect program. She characterized the discrepancy as "CEI South inexplicably walk[ing] back its offer of a more reasonable approach that would have benefited residential ratepayers by giving these customers more time to become aware of Petitioner's new disconnection process." She concluded that this settlement term is not in the public interest and stated the OUCC objects to the Settlement Agreement's 30-day notice and recommends approval of the three-month communication campaign referenced in Ms. Folz's rebuttal testimony.

Ms. Paronish recommended that, since CEI South indicates the language she proposed may be modified, the Commission should afford the OUCC at least seven business days to review and comment, if necessary, on CEI South's proposed modified language. Pub. Ex. 13-S at 8.

CAC witness Inskeep testified that the consumer protections in the Settlement Agreement are "too modest to significantly reduce the rate of disconnection, especially in light of the proposed bill increase that will increase the likelihood of arrearages." CAC Ex. 6 at 21.

vii. <u>Settlement Rebuttal</u>. CEI South witness Rice responded to Mr. Inskeep's concerns about the consumer protections accompanying the ARP for remote disconnects, noting objection to Petitioner's proposed ARP is no reason to reject the Settlement, since the terms included within the Settlement Agreement that relate to remote disconnections are expressly left to the Commission's determination as to approval of the ARP. Pet. Ex. 19-SR at 24.

In response to Ms. Paronish's concerns that CEI South retracted its three-month minimum advance notice before remote disconnections begin, Mr. Rice explained that was not CEI South's intention. He reiterated that Section 9 of the Settlement Agreement specifically provides "CEI South agrees to incorporate the protections contained in the rebuttal testimony of CEI South witness Folz" and that Section B.10 of the Settlement Agreement then addresses the minimum amount of time that CEI South would wait following an order to disconnect, stating "CEI South will provide at least thirty days advance notice to customers before implementing the remote disconnection/reconnection proposal." He testified that CEI South will keep its commitment to communicate approval of the ARP in a campaign to update customer contact information three months in advance of beginning remote disconnections should the ARP be approved by the Commission. He explained that doing so will not conflict with the Settlement Agreement. Mr. Rice also indicated CEI South's agreement to afford the OUCC seven business days to review the language CEI South intends to use during the three-month campaign to solicit customer information.

viii. <u>Commission Discussion and Findings</u>. This Commission has previously granted waivers from 170 IAC 4-1-16(f) to electric utilities to allow for remote disconnection for non-payment. 170 IAC 4-1-16(f) provides that prior to disconnection of electric service, a CEI South employee is required to, among other things, make an on-site premises visit. On rebuttal and through the Settlement Agreement, CEI South has committed to undertake a campaign to notify its customers of its ability to remotely disconnect/reconnect upon our approval of the requested waiver. As discussed in greater detail in Paragraph 0.L (Customer Protection Provisions and Bill Transparency) of this Order, CEI South has agreed to certain continuing protections for its customers. Medical need customers and life support customers will be exempt from the remote disconnection process and will continue to have field personnel on premise, as will customers who do not have AMI installed. Pet. Ex. 5 at 12; Pet. Ex. 5-R at 4. In addition, if at the time of the disconnect for non-payment, CEI South is notified that a customer is applying for, or received funds for, LIHEAP during that current LIHEAP season, CEI South would not process the disconnect for non-payment during that LIHEAP season. Pet. Ex. 5 at 16.

Given that Petitioner's waiver request is part of an ARP under Ind. Code ch. 8-1-2.5, we proceed to our findings under the four criteria set forth in that chapter for granting an ARP. We must determine:

> (1) whether technological or operating conditions, competitive forces, or the extent of regulation by other state or federal regulatory bodies render the exercise, in whole or in part, of jurisdiction by the commission unnecessary or wasteful;
> (2) whether the commission's declining to exercise, in whole or in part, its jurisdiction will be beneficial for the energy utility, the energy utility's customers, or the state;
> (3) whether the commission's declining to exercise, in whole or in part, its jurisdiction will promote energy utility efficiency;
> (4) whether the exercise of commission jurisdiction inhibits an energy utility from competing with other providers of functionally similar energy services or equipment.

The record shows that, due to the advancement in technology and through the use of AMI, there are safer and more effective ways to notify a customer of potential disconnect due to non-payment and to ultimately disconnect the customer than what was historically available when 170 IAC 4-1-16(f) was promulgated. Modern technology allows CEI South to notify the customer multiple times and in many different forms in the event of a potential disconnect. Further, through the use of AMI and the remote connect/disconnect capability, CEI South does not need to be physically present on the customer's premises to connect or disconnect service. Thus, the goals of 170 IAC 4-1-16(f) – to sufficiently notify a customer of potential disconnect and to identify oneself while on a customer's property – can be achieved in a safer and more effective way through the use of modern technology because AMI allows for remote connect and disconnect.

The record also reflects that this Commission's approval of CEI South's proposed ARP will be beneficial for the utility, its customers, and the state, as remotely performing disconnect for non-payment orders will further reduce safety risks, improve work efficiencies, and significantly reduce the reconnect charge for remote reconnects. CEI South will be able to complete disconnects for non-payment more safely, quickly, and efficiently through the remote disconnect capability through AMI than through the traditional truck roll and field personnel being dispatched to the customer's premise.

The exercise of this Commission's jurisdiction would inhibit CEI South from competing with other providers of functionally similar services or equipment insofar as it would deny CEI South a waiver of a requirement that has been waived for other similarly situated utilities in the State of Indiana. We have approved similar waivers for Duke Energy Indiana in Cause No. 45253, Indiana Michigan Power in Cause No. 45567, and AES Indiana in Cause No. 45911.

Based on the evidence of record, we find that CEI South's proposed ARP to provide a waiver of the requirement of an on-site premises visit prior to disconnection is in the public interest and so approve it. CEI South shall pursue the three-month customer communication plan outlined in Ms. Folz's rebuttal testimony and incorporated into the Settlement Agreement by reference regarding the Commission's waiver of the premises visit being approved in this order. We find that CEI South should provide the OUCC seven business days to review language to use during the three-month campaign to solicit customer information. Pet. Ex. 19-SR at 25.

We reject CAC witness Inskeep's recommendation to impose a moratorium on CEI South for disconnections, as it is contrary to the Commission rules (170 IAC 4-1-16) that allow for disconnection due to non-payment under certain conditions. The evidence shows that imposing a mandatory, 12-month delay in disconnections due to non-payment would counteract affordability efforts as it could cause customers' arrears payment obligations to become larger than they would be with timely disconnections for non-payment.

L. <u>Customer Protection Provisions and Bill Transparency</u>.

i. <u>OUCC Position</u>. OUCC witness Paronish raised issues about CEI South's billing. She alleged that the bills do not provide an itemization of the specific billing components. She noted that a customer can receive an itemization only upon request. She recommended that all customers receive an itemized breakdown of all components of the bill. Pub. Ex. 13 at 15-16. She also complained that there had been unusually higher bills received by customers during the period December 2023-January 2024 due to a longer-than-normal billing cycle. She recommended that the billing cycle be no longer than 32 days. Pub. Ex. 13 at 17-18.

ii. <u>CEI South Rebuttal</u>. Mr. Rice testified in response to Ms. Paronish's issues with the format of the CEI South bill. He noted that very few customers request an itemized bill – in 2023 it was 130 out of a total of nearly 2 million bills – and that most of those questions are about the gas portion of combined bills. He also explained that CEI South is willing to provide more detail on the bill and may be able to do so as a part of the new billing system being deployed in Summer 2024. He noted that the team's focus is currently on ensuring bills are accurate and go out on time when the cut over occurs. However, CEI South is reviewing options to increase the level of information on the bill following the cut over. Pet. Ex. 19-R at 49-50.

Mr. Rice also responded to the testimony about the longer-than-normal billing cycle issue, explaining that this was due to the implementation of the billing system change. CEI South had postponed conversion to a new billing system that was originally scheduled to take place at the beginning of the year. This created one-time bills that had a longer than normal billing cycle. He expressed regret and noted that CEI South works to keep the typical billing cycle as close to 30 days as possible. To help affected customers, CEI South had waived late fees for all customers that received a longer than normal billing cycle. He also noted that CEI South planned to move to the new billing system on July 1, 2024, and is working to keep billing cycles as close to 30 days as possible to minimize the potential for high bills caused by longer than normal billing cycles. Pet. Ex. 19-R at 4-5.

iii. **Settlement.** Mr. Rice summarized the customer protection provisions set forth in Section B.10 and compared those provisions to similar terms that had been included and recently approved in other proceedings before the IURC. He presented a comparison of the consumer protections incorporated in the Settlement Agreement and those approved in other settlement agreements. Pet. Ex. 19-S at 19. The protections include:

- Limiting the residential deposit for LIHEAP Qualified Participant customers (Settling Parties' Jt. Ex. 1 at Section B.10.a)
- Waiving, once a calendar year at the residential customer's request, a late payment charge (Settling Parties' Jt. Ex. 1 at Section B.10.b)
- Stipulating and agreeing to certain reporting requirements related to LIHEAP Qualified Participant customers, and waiving certain fees for such customers. (Settling Parties' Jt. Ex. 1 at Section B.10.c)
- Stipulating and agreeing to not disconnect service for any residential customer on Fridays, Saturdays, Sundays and during eight specified holidays. (Settling Parties' Jt. Ex. 1 at Section B.10.d.ii)
- Stipulating and agreeing to increase the current protection from disconnection for Medical Need (10 days) or Life Support (20 days) to 30 days for both categories. Before any disconnection of a LIHEAP Qualified Participant designated as Medical Need or Life Support, CEI South will place a collection call to such customer that prompts the customer to contact CEI South to establish an installment plan. (Settling Parties' Jt. Ex. 1 at Section B.10.d.iii).

In addition, if CEI South's request for an ARP is approved by the Commission, Section B.10.d includes several provisions related to remote disconnection/reconnection:

- Agreeing to provide at least 30-days advance notice prior to implementing any remote disconnect for nonpayment program (Settling Parties' Jt. Ex. 1 at Section B.10.d.i.1)
- Reducing the fee for remote reconnection from $5 to $3 (Settling Parties' Jt. Ex. 1 at Section B.10.d.i.2)
- Waiving, once a calendar year, the after-hours remote reconnection charge set forth in CEI South's tariff as $54.19 (Settling Parties' Jt. Ex. 1 at Section B.10.d.i.3)
- Stipulating and agreeing to certain additional protections for customers designated as Medical Need or Life Support (Settling Parties' Jt. Ex. 1 at Section B.10.d.i.4)

See Pet. Ex. 19-S at 19.

Mr. Rice testified that, as a result of the billing system upgrade, and in response to consumer concerns related to transparency of bills, the Settling Parties stipulated and agreed that CEI South will provide more transparency on its customer bills as soon as practicable after the issuance of a Final Order and after implementation of its new billing system – EIP Phase 2, to include additional line items that break out: (1) Service Charge; (2) Variable charges (charges tied to usage); (3) FAC; (4) Sales Tax; and (5) the Total. In Section B.12 of the Settlement Agreement, CEI South agreed to provide a copy of these changes to the bill format to all parties to this Cause prior to implementation.

iv. <u>Settlement Opposition</u>. Ms. Paronish testified that the Settlement Agreement did not address all the issues she raised in her direct testimony. She indicated that the Settlement does not respond to bills that may be issued on more than a 30-day billing cycle, which can lead to high bills. She requested the Commission, to the extent possible, to enforce the "Bills will be rendered monthly" provision contained in CEI South's Terms and Conditions, Sheet No. 80, page 6 and the reference to "monthly" rates and charges in Rate RS Residential Service, Sheet No. 10, p. 1. Pub. Ex. 13-S at 9. As to the billing system upgrade, she testified "it is both unfortunate and nonsensical" that CEI South did not explore the potential for an automated detailed billing solution before cutting over to its new system as of July 1, 2024. She recommended the Commission direct CEI South to comply with the OUCC's position regarding bill transparency, as set forth in her direct testimony, and provide a more detailed breakdown within customers' bills. Furthermore, if CEI South cannot automate its process for customers to receive monthly detailed bills, she recommended the Commission direct Petitioner to find a way to capture the customers who want to have a monthly bill and effectuate this billing without customers needing to call each month. Pub. Ex. 13-S at 11.

CAC witness Inskeep took issue with the Settling Parties including terms to which the CAC had agreed in other settlements. He noted the other settled cases were non-precedential and argued they cannot be considered by the Commission in other proceedings. CAC Ex. 6 at 16-17. He also disputed that the inclusion of these consumer protection provisions alleviated his overall concerns with the Settlement Agreement.

v. <u>Settlement Rebuttal</u>. Mr. Rice disputed Mr. Inskeep's view of citation of past settlements and also responded to witness Paronish's opposition. As to her claim that it was "nonsensical" that CEI South had not evaluated an automated solution to her bill transparency concerns before cutting over to the new system, he testified that CEI South did evaluate this option, but it was not feasible to incorporate this update prior to the system cut over on July 1, 2024. He stated meeting that system cut-over was the most important task. Pet. Ex. 19-SR at 19. As to the level of detail in the bill, Mr. Rice testified that CEI South's bills fully comply with the Commission's rules, which set forth at 170 IAC 4-1-13 the level of detail that is required to be set forth on electric bills. Nevertheless, he stated CEI South committed to breaking out fuel cost on a separate line and including all other trackers in one line called variable charge. The variable charge would include all charges from trackers.

He stated that CEI South does not believe that it is necessary to create a rate from the variable charge line, as witness Paronish suggests. This rate would not be found in CEI South's tariff and would drive confusion rather than help provide clarity. Pet. Ex. 19-SR at 20. As to billing frequency, he explained that Ms. Paronish is referencing a single unfortunate isolated incident in December 2023, which was the original system cut over for the new billing system. Lessons were learned and the amount of time in each billing cycle was minimized to prevent this from happening again when the system cut over eventually occurred in July. He testified that Ms. Paronish's request would impose a requirement that is unnecessary and not imposed on any other Indiana electric utility.

vi. Commission Discussion and Findings. Regarding the consumer protections, we find them to be appropriate concessions that assist with maintaining affordable electric rates for the most financially challenged customers in the residential class. As to Mr. Inskeep's objection to the Settling Parties including terms that the CAC had agreed to in other settlements, the Commission may consider the terms of past settlements as persuasive on a case-by-case basis. While prior settlements may not be precedential, they also are not inherently required to be completely ignored when considering settlements among other parties. In other words, the terms of other settlements may be persuasive. In this proceeding, we find these consumer protection terms to be reasonably included in the Settlement before us.

The level of detail in the billing statement to which CEI South has agreed is sufficient and reasonable based on the evidence of record. 170 IAC 4-1-13.

M. Cost of Service and Rate Design; Multi-Family Rates; BAMP.

i. CEI South's Case-in-Chief. CEI South witness Taylor presented CEI South's COSS and rate design. He proposed the use of the 4CP method for allocating production cost, which allocates demand-related costs based upon the coincident peak during the four summer months of the historic base period. He analyzed several years of monthly peak loads (2010-2022) and applied the FERC's three-peak ratio tests. These tests are used by the FERC to determine when a 12CP method is appropriate. The years 2022, 2021, 2020, 2019 and 2017 failed all three tests and 2018 failed two of the three tests. He recommended CEI South continue to use the 4CP methodology, consistent with CEI South's last rate case. Pet. Ex. 18 at 11-12.

For transmission demand-related costs, Mr. Taylor recommended the 12CP method. Pet. Ex. 18 at 13.

For the distribution system, he used non-coincident peak demand to allocate demand-related costs. Pet. Ex. 18 at 13. To determine the demand/customer split for distribution system costs, he relied upon a minimum system or zero intercept study for transformers, consistent with CEI South's last rate case.[22] Poles, overhead conductors, underground conductors, and conduit were classified as demand-related and allocated on non-coincident peak demand.

Mr. Taylor presented the results of his study, demonstrating the revenue deficiency/excess for each class and the class rate of return. He set street lighting service at its cost to serve, and the resulting increase in revenues was used to reduce outdoor lighting. Water heating service was increased by 1.5 times the system average. The remaining rate classes were increased proportionately. Pet. Ex. 18 at 21. Table JDT-4 presents the proposed revenue increase by class.

Mr. Taylor proposed increases in customer charges to move closer towards straight fixed variable pricing. Pet. Ex. 18 at 23-26.

[22] *CEI South*, Cause No. 43839, 289 PUR4th 9 (IURC 4/27/2011), p. 65, 2011 WL 1690057.

Within Rate BAMP, Mr. Taylor proposed modifications to make the Backup and Maintenance Service rate a daily charge, to use the applicable customer rate charge for base service charges, to set backup services for capacity at 110% of MISO's Cost of New Entry ("CONE"), to set backup services for energy at daily MISO LMP, and to base backup services for transmission and distribution on the ACOSS unit costs. Pet. Ex. 18 at 26-27.

Mr. Rice described CEI South's proposed updates to Rate BAMP, including updating the name to Base, Backup, and Maintenance. There are three main influences in the update of Rate BAMP. First, a better differentiation between firm and non-firm for both Rate BAMP transmission and distribution services was clarified. Second, Rate BAMP was adjusted to reflect backup on a daily basis, rather than monthly. Third, Rate BAMP now points to MISO's CONE to provide a more appropriate price signal for capacity. Pet. Ex. 19 at 22. Customers that require firm transmission and distribution service receive instantaneous backup without a break in electrical service. Interruptible customers have a minimum of one hour between a trip event and restoration of service. When backup events occur, these events tend to occur over days and not months. As such, CEI South is proposing to bill customers in a way that is more reflective of how co-generation equipment operates. The generation capacity used to supply the Backup Service provided by Rate BAMP is incremental by its nature. CEI South is located in MISO's Zone 6. MISO's Zone-specific CONE rate represents the generation capacity cost of the newest generation combustion turbine unit within a particular MISO geographical area. CEI South does not include Rate BAMP backup kW in its generation plan or reserve planning. Therefore, assigning a specific CEI South generation capacity amount to Rate BAMP does not make sense. Rate BAMP customers benefit by being able to pay generation capacity "rent" by the day, only when needed, and without prior notice for what is a year-round fixed cost for non-Rate BAMP customers. A Rate BAMP customer will have the choice to buy-through a trip event and pay the real time available MISO LMP for Backup Energy or reduce load and pay no Backup Energy charges. It is expected that these changes will better match Rate BAMP revenue with cost. The Rate BAMP transmission and distribution rates are subcomponents of other rate schedules that were updated in the ACOSS provided by witness Taylor. Mr. Rice also testified that CEI South is proposing to place in base rates $4,557,012 of backup charges and place variances from the base backup rates in the RCRA for capacity and the MCRA for transmission variances.

ii. <u>OUCC's Position</u>. OUCC witness Dismukes objected to Mr. Taylor's ACOSS to the extent it classifies fixed costs associated with production plant assets as exclusively demand-related. He testified that Mr. Taylor assumes that the only purpose of these assets is to support maximum system demands and that such an assumption is inconsistent with the dual role these production/generation assets play in serving both peak demand and low-cost energy requirements for off-peak periods on CEI South's system. He testified that equally important is the fact that CEI South's proposed classification ignores the significant portion of its current production plant in service that is associated with renewable generation assets, which provide very limited capacity benefits and should not be exclusively classified as demand related. Pub. Ex. 12 at 21. He noted that Average and Peak cost allocation methodology, also called the Peak and Average ("P&A") cost allocation methodology, as well as the Average and Excess cost allocation methodology, more appropriately recognize the dual functions of production plant. He further analyzed the split between demand and energy using individual generation unit capacity factors. For non-renewable generation, facilities with an annual capacity factor less than 15% were assumed to be fully classified as demand, while those units with a capacity factor greater than 15%

were divided between energy and demand. He presented Exhibit DED-5, showing that 47.32% of non-renewable generation was devoted to the provision of energy.

He next reviewed the levelized cost of each generation unit relative to established market analyses. Exhibit DED-6 presented the results of an analysis that examines the levelized annual cost for each of CEI South's non-renewable units compared with the CONE prices estimated by MISO in its most recent analysis of the 2023/2024 Planning Resource Auction results. He concluded that costs less than the MISO CONE price can be classified as demand-related, whereas prices above the MISO CONE can be classified as energy-related. Pub. Ex. 12 at 27-28. Based on this levelized cost analysis in Exhibit DED-6, he testified that, at most, 45.31% of CEI South's non-renewable production plant in service could be classified as being associated with the provision of demand functions.

Witness Dismukes was also critical that CEI South's classification ignores the significant portion of CEI South's production plant in service related to renewable generation. He stated that renewable generation facilities provide limited capacity service for a utility, mainly providing energy service for a utility. He noted that nearly 52.5% of CEI South's test year net plant in service is associated with non-dispatchable solar renewable generation resources. Pub. Ex. 12 at 33. He testified that renewable generation should be classified as 100% energy-related, and that when this is done, 26.2% of CEI South's test year net plant in service should be classified as energy-related, with the remainder classified as serving joint demand and energy. He ultimately concluded that 61.49% of CEI South's production plant costs should be classified as energy-related, with the inverse (38.51%) being classified as demand related for the test year.

He was also critical of the minimum system study ("MSS") because it assumes that there is a hypothetical "minimum system," even though a minimum system would have the capability of serving some load. He cited the National Association of Regulatory Utility Commissioners Cost Allocation Manual ("NARUC Manual") as recognizing this challenge. Pub. Ex. 12 at 39. He claimed that the true driving factors of utility distribution system costs are much more complicated and depend on a host of other factors, such as the size of a service territory and the population density within. The incremental costs of constructing an appropriate distribution system to serve an additional customer within an urban area with existing nearby infrastructure is substantially less than the costs to extend an existing utility system by potentially miles to serve an additional customer located in a rural area, which he claimed is inherently ignored by a MSS. He ultimately recommended that the Commission reject CEI South's MSS. He instead recommended that distribution costs be allocated as 100% demand-related.

Witness Dismukes also disagreed with CEI South's proposed revenue allocation and rate design. He contended that capping the increase at 1.5 times the system average was inconsistent with gradualism and affordability. He instead recommended that limits to individual classes be capped at 1.15 times the overall system average increase. Pub. Ex. 12 at 4. Finally, he opposed CEI South's proposal to increase customer charges. He also recommended the Commission direct CEI South to eliminate its design of the TDSIC as a fixed charge. He claimed that CEI South's proposed increase to its base customer charges and its current practice of increasing its monthly customer charge through fixed TDSIC charges detrimentally impacts the public policy goals of promoting energy efficiency and burdens low-use customers.

iii. **<u>CAC's Position</u>.** CAC witness Barnes presented the CAC's alternative COSS and rate design. He recommended that production costs be allocated based upon the Probability of Dispatch ("POD") method. He testified that the 4CP method fails to reflect the diverse and evolving character of CEI South's generation fleet, ignoring factors such as the operational characteristics of different types of facilities (*e.g.*, baseload, peaker units, intermittent resources), the role that energy loads and long-term energy costs play in resource planning, and a shift in the MISO reliability planning paradigm to a seasonal construct. CAC Ex. 3 at 7. He testified that CEI South's projected suite of rate-based generation resources that would be allocated using the 4CP allocator includes multiple resource types with varying operational profiles and other characteristics, including Posey Solar and the CT Project. He also pointed to the MISO seasonal resource adequacy construct, setting requirements for each of the four seasons of summer, fall, winter, and spring. He testified that an accurate cost allocation methodology must consider the multitude of factors that drive investment decisions, which requires consideration of time-varying loads throughout the day and year, resource adequacy requirements, and how different resources are actually used to meet those needs. He ultimately concluded the POD method of production cost allocation provides the most accurate reflection of cost causation because it reflects the hourly characteristics of both electric demand and the generation resources used to meet that demand. The POD method establishes an hourly cost at the generation unit level by dividing each generation unit's costs by the hours that it operates, assigning those costs to those hours of operation, and then allocating those costs to customer classes based on their contributions to hourly loads. He prepared a POD allocation and compared it to the 4CP, which showed a reduction for residential. He cited the Commission's order in Duke Energy Indiana's rate case in Cause No. 45253 as a reason why cost allocation should evolve.

Witness Barnes also objected to the allocation of expenses included in FERC Accounts 911 and 912 as customer-related. He noted that CEI South had indicated in discovery that it had included DSM program costs in base rates in these accounts but was willing (if there was objection) to continue to recover these costs through the tracker. Witness Barnes indicated the DSM program costs should not be recovered through base rates and the remainder of costs included in these accounts ($1,165,148) should be allocated based on total revenue requirement. CAC Ex. 3 at 28.

After citing evidence concerning the magnitude of the requested increase, he testified that the Commission should conclude that a rate impact mitigation mechanism is not only warranted, but critically necessary to moderate disparate and ultimately unreasonable rate increases on different rate classes. He proposed a rate increase mitigation methodology under which no class receives a percentage revenue increase more than 20% greater or 20% less than the system average revenue increase. CAC Ex. 3 at 37.

Witness Barnes also proposed different allocations for various trackers. He disagreed in part with CEI South's correction to 12CP for the MCRA allocation because significant portions of the MISO costs that are incorporated within the MCRA are allocated to CEI South based on its share of monthly peak loads, not only loads during summer peak hours. He added that the use of a singular 12CP allocation factor for all MISO costs does not fully reflect the character of all MISO changes encompassed by the MCRA. CAC Ex. 3 at 42. He proposed that CEI South be directed to allocate costs reflected in the MCRA according to the way MISO charges CEI South for those costs. Likewise, he stated the base rates component of MISO costs should reflect an approximate or generalized portion of MISO costs consistent with a typical breakdown of energy-based or demand-based MISO charges based on the recent history of MISO charges to CEI South. For the ECA, he disagreed with a 4CP production demand allocator, asserting it is not an accurate reflection of the cause of costs for CEI South's ongoing environmental projects, which include significant costs for CCR mitigation. He testified that the creation of CCRs has no plausible relationship to the peak demands used in the 4CP allocator, or any variety of peak demand allocator for that matter. He testified that, based on the most recently established revenue requirements, the allocation of ECA should be 42.5% energy and 57.5% demand. For the CECA, he testified that the costs should be allocated according to the POD method that he recommended for allocation of production related costs, which would create consistency between allocation regimes.

Finally, Mr. Barnes objected to the proposed treatment of special contract revenues in the COSS. CEI South excludes Ind. Code § 8-1-2-24 contract customers from the ACOSS used to establish the general class cost allocation proposal. That is, the allocator percentages that are used to allocate costs in the ACOSS (*e.g.*, 4CP and 12CP) exclude load from Section 24 contract customers. Instead, he stated that the proposed rates and revenue requirements for Section 24 contract customers are determined outside of the cost of service model, and associated revenues from Section 24 contracts are allocated to all classes as Other Revenues. Mr. Barnes instead recommended that CEI South be directed to fully incorporate Section 24 contracts into any new cost of service evaluations that they perform, such as in future rate cases or any other applicable proceedings, to provide a transparent picture of subsidization and cost-shifting issues that such special contracts inherently raise. CAC Ex. 3 at 58.

Regarding rate design, Mr. Barnes objected to the proposed customer charges. First, he questioned that the underlying premise that all costs associated with the shared distribution system are "customer-related" and should therefore be recovered via a fixed monthly customer charge design is inconsistent with cost causation. Second, he claimed that CEI South's calculation of the fixed ($/month) component of the residential TDSIC rate ignores the current limitation on increases in the fixed charge component under the settlement that gave rise to the TDSIC fixed charge, which, if continued through 2025, would limit it to an average 2025 rate of $7.75/month. Relatedly, he stated CEI South's assertion that the proposed residential customer facilities charge will not produce an incremental impact on low-usage customers is misleading because it assumes that the 2025 fixed charge component of the TDSIC will in fact be significantly higher than a rate constrained by the current fixed charge increase limits. CAC Ex. 3 at 60. He claimed that only those portions of the system that serve individual customers, the meter and the service drop, are allocated based on customer numbers. As to the TDSIC, he claimed that CEI South's current TDSIC is governed by a settlement adopted by the Commission which provides for a maximum semi-annual increase of $0.50/month capped at $7.00/month over the seven-year period of CEI South's TDSIC. He testified that if one were to accept CEI South's stated intention of a 1:1 movement of the TDSIC fixed charge into the residential customer facilities charge, the fixed rate would be $18.59/month, not $23.20/month. He recommended that the residential customer facilities charge be established based on the so-called "Basic Customer Method," which confines the customer charge to those costs that are directly attributable to an individual customer, such as metering and billing, excluding portions of the distribution system shared by multiple customers. He explained that many states do not accept the underlying conceptual premise that there is a customer-related component to the costs of the shared distribution system. Apart from that core reason, a rate design weighted towards fixed charges produces a smaller customer incentive to pursue energy efficiency because collecting a larger amount of revenue via fixed charges lowers the amount to be collected from other charges. He calculated a residential customer facilities charge of $8.71/month based on the Basic Customer Method.

Mr. Barnes also recommended that a multi-family rate schedule be studied. CAC Ex. 3 at 71.

CAC witness Inskeep similarly opposed the proposed residential fixed charge and compared the proposal to Indiana's other five electric investor-owned utilities. CAC Ex. 2 at 59.

Mr. Inskeep also proposed an Affordable Power Rider. The Affordable Power Rider would be a new rider providing a tiered discount mirroring the current Universal Service Fund Rider discount percentages used by CEI South Gas (15% at Tier 1, 26% at Tier 2 and 32% at Tier 3), with costs recovered through a per kWh charge assessed identically on all retail sales. CAC Ex. 2 at 32. He claimed that bill discounts applied to low-income customer bills would first and foremost help eligible customers afford their CEI South electric bill, which would encourage timely bill payments, reducing delinquencies, arrearages, and disconnections. He said this improves CEI South revenues and customer satisfaction in the long run.

iv. <u>Industrial Group's Position</u>. Industrial Group witness York agreed with CEI South's allocation of production costs on the basis of a 4CP demand as being consistent with CEI South's historic practice, cost-causation and sound ratemaking. For transmission costs, she disagreed with CEI South's proposal to deviate from its established method of allocating by shifting to a 12CP basis. Instead, CEI South should continue in this case to allocate transmission costs on a 4CP basis, as it has historically. In addition, she claimed that CEI South's ACOSS does not accurately measure its cost of providing service to each customer class, due to an inaccurate classification and allocation of distribution costs. Indeed, CEI South's classification of distribution cost in its ACOSS does not follow CEI South's own accurate stated policy on the proper classification of distribution costs. She agreed that a significant portion of distribution system costs are incurred simply to connect customers to the system, regardless of electric demand, but stated CEI South's ACOSS ignores this reality. Specifically, she testified CEI South's ACOSS fails to classify a portion of costs included in the FERC Accounts 364, 365, 367, and 368 as customer related. Instead, CEI South classifies and allocates these costs on only demand and, thus, does not properly allocate these costs across rate classes. She also proposed that CEI South's FAC should be modified to recognize the capacity component of renewable resource costs. Renewable resources contribute to the MISO resource adequacy requirements. The capacity component of renewable resource costs should be allocated across rate classes using the production demand allocator established in CEI South's most recent rate case, and the renewable resource capacity costs should be recovered from LP, BAMP, and HLF customers using a demand charge. IG. Ex. 2 at 3-4.

She testified that the change from 4CP allocation of transmission costs is not supported based on CEI South's monthly system demands. CEI South has not identified any material change in system characteristics or operational circumstances since its last rate case to justify the proposed change in allocation methodology. The transmission system must be sized to be able to deliver power from the production resources to the distribution delivery point in all hours of the year, including the peak hour. Hence, the amount of transmission capacity needed to reliably deliver power to the distribution delivery point is based on the coincident peak hour demands. Also, transmission capacity should be allocated in a similar manner as production capacity because they are interdependent. IG Ex. 2 at 9.

As to distribution costs, she testified that CEI South separates distribution costs in FERC Accounts 364 (Poles, Towers and Fixtures), 365 (Overhead Conductors and Devices), and 367 (Underground Conductors and Devices) between primary and secondary distribution voltages. Primary distribution voltages range from 600 volts ("V") to 12.5 kilovolts ("kV"), while secondary voltages are less than 600 V. CEI South allocates primary voltage distribution costs to all customer classes, but does not allocate secondary voltage distribution costs to customer classes that do not take service from secondary voltage distribution infrastructure, such as the LP and HLF classes. CEI South classifies the costs in FERC Accounts 364, 365, and 367 as entirely demand-related, rather than a combination of demand- and customer-related. She testified that CEI South's approach of allocating such costs only on demand fails to recognize that there is a utility cost simply to connect each customer to the grid.

Ms. York testified that classifying a portion of distribution costs in these accounts as customer-related is common and widely accepted in the industry and is supported by the NARUC Manual. She noted that Chapter 6 of the NARUC Manual discusses the classification and allocation of distribution costs. In this chapter, the NARUC Manual describes methods for classifying distribution costs in Accounts 364 through 368 and classification methods containing both customer and demand components. None are shown as demand only. Multiple methods for determining the demand and energy classification are discussed, such as "Minimum Size Method" and "Zero Intercept Method," yet none yield results of zero cost being classified as customer-related for these accounts. In addition to the wide acceptance in the industry and inclusion in the NARUC Manual, Ms. York explained that it requires little more than common sense to understand that some portion of the installation of poles, conductors, underground conduit and conductors, and line transformers are undertaken simply to connect customers to the grid, even though their demands may be very small, well below the capacity of the minimum sized facilities needed to serve them. The aggregate demand level of customers certainly affects the sizing of these distribution facilities (over and above the minimum levels), but that does not in any way nullify the fact that a portion of the investment is in the minimum system and caused by the existence of the customers. IG Ex. 2 at 10-11. She sponsored her own MSS, where she estimated the customer component of the distribution costs based on a Minimum Size approach. CEI South provided information on the replacement cost and quantity of the assets included in FERC Accounts 364, 365 and 367. Her analysis is contained in Attachment JAY-2. These customer percentages were significantly higher than the customer-related portion of costs in Account 368 developed by CEI South using CEI South's MSS. To be conservative, she applied the lower customer component of 56%, as calculated by CEI South for FERC Account 368, to FERC Accounts 364, 365, and 367.

v. <u>SABIC's Position</u>. SABIC witness Coyle proposed that the share of CEI South's transmission costs that should be collected through Backup Transmission Service rates should be derived using probability-adjusted calculation of Backup Service demand. She also claimed that proxy capacity costs used to determine Backup Generation Capacity rates should be increased by no more than 7% for administrative and general expenses, rather than the 10% proposed by CEI South. Consistent with CEI South's redesign of Rate BAMP, production-related rate adjustment mechanisms should no longer apply to Backup Generation Service. She agreed with witness York that demand-related transmission costs should be allocated to customer classes using a 4CP allocator, consistent with the quantitative evidence presented by CEI South and Commission decisions in past cases. She reviewed CEI South's load profile, applied the FERC tests for 12CP, and concluded that CEI South's system did not warrant the use of 12CP and that the FERC tests could not be satisfied. SABIC Ex. 1 at 31.

vi. **<u>Cross-Answering Testimony</u>.** CAC witness Barnes objected to witness York's and witness Coyle's proposal to use a 4CP allocation method for transmission service. He claimed the 12CP method provides a "somewhat more balanced allocation regime." He also continued to state that the Commission should adopt the POD allocation method for renewable resources included in the FAC in light of the issue regarding renewable resource cost allocation in the FAC raised by witness York. He recommended the Commission reject witness Coyle's proposal to revise the methodology under which BAMP customers are charged for Backup Transmission Service because it amounts to a collateral attack on the known terms of the BAMP tariff and would result in unreasonable cost-shifting to non-BAMP customers. Further, he testified the Commission should reject witness Coyle's proposal to modify the BAMP tariff to eliminate the applicability of cost trackers associated with legacy generation costs because doing so would absolve BAMP customers from paying their fair share of costs caused by their historic use of those generation resources. He also opposed witness York's MSS proposal for many of the same reasons that he had opposed witness Taylor's MSS. Finally, he opposed witness Dismukes's proposed customer charge in favor of his own proposed customer charge. CAC Ex. 5 at 3-4.

IG witness York testified that other parties had allowed concerns over affordability to the residential class to influence their recommendations concerning cost allocation, in deviation from the purpose of a COSS to determine cost-causation. IG Ex. 3 at 5. She opposed witness Dismukes's production split between demand and energy and use of the P&A approach. She further opposed witness Barnes's use of the POD method for production plant. She noted that neither witness cited any prior Commission electric orders adopting either the P&A or POD allocation methods. She opposed witness Inskeep's proposed Affordable Power Rider as not being based on cost causation. She also rejected witness Barnes' recommendation to allocate CCR costs within the ECA Tracker based on energy.

vii. **<u>CEI South's Rebuttal</u>.** Witness Taylor presented an updated COSS based upon CEI South's rebuttal revenue requirement. In addition, he corrected the allocation to 4CP for a few accounts as identified by witness Coyle. Further, he corrected an error identified by witness York that the original study did not allocate transformers based upon CEI South's MSS. Pet. Ex. 18-R at 6.

As to the recommended changes proposed by witnesses Dismukes and Barnes, Mr. Taylor noted that neither of them had demonstrated a change in the operational characteristics of CEI South's system warranting a change in allocation of production costs. CEI South remains a predominantly summer peaking system. In his opinion, there have not been enough changes in the system planning requirements nor the operations of the system resources that would give rise to even consider the radical changes in allocation methodology they recommend. Pet. Ex. 18-R at 9. What drives the selection of a resource is the need to meet an identified resource adequacy at a reasonable cost. The fact that resources may also provide an energy benefit is secondary and does not change that the resource was added to supply capacity. He cited a series of Commission orders rejecting proposals to use an energy component in the classification of production plant.

He opposed witnesses Coyle and York's proposals to use 4CP for transmission plant. He claimed that the transmission system and production plant are not planned in the same manner. Pet. Ex. 18-R at 19.

As to distribution plant and the MSS, he agreed in principle with witness York's proposal to include additional accounts in the MSS, but indicated CEI South's proposal was to use the MSS only for transformers, consistent with the last case. He presented the results of his ACOSS using the broader MSS recommended by witness York. It would produce a significantly greater allocation of costs to the residential class. Pet. Ex. 18-R at 22-23.

As to witness Barnes's recommendations regarding energy efficiency programs, Mr. Taylor testified CEI South agreed to move DSM-related costs to the tracker. For the remaining expenses in Accounts 911 and 912, Mr. Taylor disagreed with Mr. Barnes's recommendation because Mr. Barnes had not presented evidence substantiating his view that expenses in these accounts correlate with revenue per class. Pet. Ex. 18-R at 24.

He rejected Mr. Barnes's approach with respect to Section 24 contracts. Mr. Taylor testified that the treatment of these customers in the ACOSS aligns with the standard approach in base rate proceedings, distributing the costs and revenues across all customer classes. He noted that CEI South is bound by contractual commitments that were approved by the Commission in docketed proceedings. Pet. Ex. 18-R at 25.

Mr. Taylor discussed witness Barnes's recommendations regarding allocation for the CECA, agreeing with Mr. Barnes that the allocation should be the same as is used for production plant. Given that he recommends 4CP for production, he opposed the recommendation to use POD. Mr. Taylor responded to witness Barnes's recommended rate impact mitigation mechanism by identifying that the CEI South proposed increase for the residential class based on the rebuttal ACOSS is 1.22 times the overall system increase.

With respect to customer charges, witness Taylor disagreed with the recommendations of Dismukes and Barnes. Pet. Ex. 18-R at 32-34. Regarding the impact on low-income customers, he noted that low income customers are often higher use customers who are negatively impacted by recovery of fixed costs through volumetric charges. As to the TDSIC as a fixed customer charge, Mr. Taylor disagreed with witness Dismukes and Barnes on multiple issues, including that rolling the TDSIC customer charge into base rates is in line with the findings of the ACOSS model. Mr. Taylor stated that this alignment indicates that when costs are integrated into base rates, the recovery of TDSIC fixed charges corresponds more closely with customer-related costs. This facilitates a better alignment of the type of cost recovery, specifically customer related costs. Based on the various customer charge analyses presented in this instant proceeding he recommended maintaining the TDSIC rate design and continuing with established practices. *Id.* at 39.

Mr. Rice testified that the affordability pillar concerns retail electric utility service being "affordable and competitive across residential, commercial, and industrial customer classes." He noted that if affordability meant producing rates that were affordable for all customers, utilities would need legislative guidance and authority not only on how to design programs aimed at assisting those who are most financially disadvantaged but also to address some of the heavier burdens they bear that are unrelated to the electric bill. Pet. Ex. 19-R at 4. He testified that, rather than Mr. Inskeep's proposed Affordable Power Rider, CEI South is in the process of converting the Share the Warmth program back to a bill assistance program, which will also benefit customers that fall into the Asset Limited, Income Constrained ("ALICE") classification. He stated what is or is not affordable is going to be different for different customers and that CEI South does not know the income of individual customers, the level of assistance that they may receive outside of LIHEAP, or the number of people in the household. Even Census Median Household Income does not present the full picture, as it does not, among other things, include non-cash benefits, such as food stamps, health benefits, or subsidized housing. He also introduced the "Relative Importance" of electricity to affordability. Using the costs of goods and services from the November 2022 Consumer Price Index ("CPI") for the U.S. Midwest Region, he noted the Electricity Relative Importance value constitutes 2.428% of the total CPI for the US and 2.255% for the CPI in the Midwest Region. Mr. Rice testified that a low Relative Importance value attributed to electricity indicates the presence of other factors possessing superior Relative Importance values, exerting a more substantial influence on affordability, particularly in the context of a general increase in the CPI. For instance, while electricity costs may contribute to overall expenses, items such as housing, transportation, and healthcare often command higher Relative Importance values within the CPI basket. Mr. Rice explained that this underscores the complexity of affordability dynamics, in which the relationships of various economic factors dictate the true impact on consumers' financial well-being. Therefore, he opined that while electricity costs remain a component of concern, a holistic understanding of the broader economic landscape is essential for effective mitigation strategies.

Mr. Rice rebutted Ms. Coyle's testimony on the BAMP rate. He summarized her position. First, SABIC believes that transmission service should be charged based on the Forced Outage Rate ("FOR") of its generating unit with what it calls "probability adjusted demand." In other words, SABIC has proposed dividing its transmission demand billing determinant by the number of days in the year and multiplying it by a FOR of 5%. SABIC would like to spread the cost difference ($3,889,940) to all other customer classes. Second, SABIC took issue with adding a 10% A&G cost to the MISO CONE for firm backup service and proposed that CEI South include a 7% A&G adder for backup power. SABIC's proposal allocates costs based on A&G Production costs only of a labor nature. Third, SABIC did not agree with being charged for CEI South production rate riders, specific to CEI South's generation fleet for Backup Power. He explained this issue was raised by SABIC during discovery, and CEI South agreed. As such, Mr. Rice made corrections to Attachments MAR-1 and MAR-2, the proposed tariff, to remove the reference to the DSMA, CECA, ECA, SCP, SRR, SAC, and RCRA appendices applying to backup service. SABIC agreed that it should be charged for transmission riders, TDSIC and MCRA, but disagreed on utilizing 12CP allocations for MCRA and proposed 4CP. Finally, SABIC raised a concern of their increase relative to the overall increase CEI South has proposed. He responded by claiming that SABIC was asking for essentially an interruptible transmission rate for firm service. Pet. Ex. 19-R at 42-48.

viii. **<u>Settlement</u>.** Mr. Taylor described how the Settlement Agreement addressed the cost of service and rate design issues in dispute. He sponsored the updated ACOSS and rate design schedules based upon the terms of the Settlement. He testified that the main issues in dispute among the parties were the allocation of production plant (with CEI South and Industrial Group's proposal of 4CP and OUCC and CAC using the P&A and POD methods, respectively, which allocate a portion of fixed production costs based on energy); allocation of transmission plant (with CEI South, the OUCC, and the CAC proposing 12CP and industrial customers advocating to retain the existing 4CP), and allocation of distribution plant (with CEI South utilizing a more limited MSS based upon the last case, with the Industrial Group advocating a more comprehensive MSS, and the CAC and OUCC eschewing the MSS altogether). He explained that the Settlement Agreement uses the 4CP for production related demand costs. He added that transmission costs are allocated based upon the 4CP as well and distribution plant would be allocated based upon CEI South's more limited MSS. He stated that all these allocation methods are consistent with the allocation used in CEI South's last rate case. Mr. Taylor explained the resolution was reasonable and favorable to the residential customer class. He presented tables in Tables JDT-S1 and JDT-S2 demonstrating that the move to 4CP on transmission resulted in only a 0.3% higher allocation for the residential class; however, use of the more robust MSS (which will not be used under the Settlement), would have resulted in the allocation of 7.7% more for residential customers. Pet. Ex. 18-S at 4-6. Notably, Mr. Taylor had not disagreed with the concept of Ms. York's more robust MSS study in his rebuttal testimony. In fact, he had specifically agreed with it but noted that CEI South wished to stay with the more limited methodology used in the prior case. Pet. Ex. 18-R at 22-23.

As to revenue allocation, the Settling Parties agreed to a conceptually similar approach to that presented by CEI South's rebuttal filing in terms of revenue increase distribution as proportion to the total requested increase. Additionally, the Settling Parties stipulated and agreed, among other things, that: (1) no class will receive a rate decrease as a result of the rates implemented pursuant to this Settlement Agreement; (2) no class will receive a rate increase that is higher than what CEI South proposed in its rebuttal position in this Cause; and (3) other than water heating as explained later, no class will receive a rate increase greater than 1.35 times the system average. The Water Heating Service ("Rate B") schedule's revenues were increased by 1.5 times the system increase, which moved them closer to their cost to serve but not completely, which would have required an increase over two times the system increase. There are no proposed changes to the Street Lighting Service ("Rate SL") and Outdoor Lighting Service ("Rate OL") in alignment with CEI South's rebuttal. A moderate increase of 3.62% for High Load Factor Service ("Rate HLF") revenue was agreed upon, compared to the 5.1% increase to that rate class proposed on rebuttal. The remaining rate classes, Residential ("Rate RS"), Small General Service ("Rate SGS"), Demand General Service ("Rate DGS"), and Large Power Service ("Rate LP"), targeted revenues proportionately below their cost to serve. He testified the settled revenue allocation is as follows:

Customer Classes	Settlement ACOSS			Rebuttal ACOSS		
	Current Revenues	**Settled Revenue Change**	**Percentage Change**	**Current Revenues**	**Proposed Revenue Change**	**Percentage Change**
Residential (RS)	$ 319,622,569	$ 46,840,706	14.7%	$ 319,953,137	$ 62,331,515	19.5%
Water Heating (B)	1,759,173	291,642	16.6%	1,763,253	421,785	23.9%
Small General Service (SGS)	14,704,649	1,070,331	7.3%	14,759,589	1,855,123	12.6%
Demand General Service (DGS)	207,073,126	17,955,496	8.7%	207,394,694	27,473,132	13.2%
Large Power Service (LP)	167,222,380	13,539,857	8.1%	166,529,378	22,927,545	13.8%
High Load Factor Service (HLF)	8,607,350	311,586	3.6%	8,601,285	436,596	5.1%
Outdoor Lighting (OL)	1,836,828	-	0.0%	1,832,443	-	0.0%
Street Lighting (SL)	3,096,774	-	0.0%	3,089,124	-	0.0%
Total Base Rate Margin	**$ 723,922,849**	**$ 80,009,617**	**11.1%**	**$ 723,922,906**	**$ 115,445,697**	**15.9%**

Pet. Ex. 18-S at 6-8.

Mr. Rice stated that the Settlement provided for minimal increases to the customer charge, and he explained that this would take the customer charges back to their level prior to the repeal of the utility receipts tax. Pet. Ex. 19-S at 22.

As to the BAMP rate, Mr. Taylor explained that the settlement resolves the disputes between SABIC and CEI South. The Settling Parties agreed on modification of the BAMP rate. Utilizing CEI South's proposed methodology to determine a cost-based Backup Transmission rate for the BAMP tariff, under the settlement revenue requirement, the BAMP Backup Transmission rate would be $0.22561. Mr. Taylor stated that the Settlement Agreement sets the BAMP Backup Transmission rate at $0.21322, which represents 95% of this cost-based rate. Mr. Taylor elaborated on cross-examination that this was a considerably higher rate than would have resulted under witness Coyle's recommendation. Mr. Rice added that the Settlement provides CEI South will evaluate the reasonableness of moving the BAMP rate towards parity with FERC Attachment O price and hold discussions with SABIC in advance of CEI South's next base rate case to determine the appropriate, cost-of service-based Backup Service Transmission Rate. Pet. Ex. 19-S at 22-23.

As to CAC's request for the study of a multi-family rate, Mr. Rice testified that CEI South does not currently have a reliable way to assess whether a home is a multi-family or single-family home, providing as example that over the years, customers remodel homes, convert single family homes to duplexes and vice versa, or add lofts and in-law suites to garages. He added that CEI South currently does not have reliable data on what premises are multi- or single family today; and the new billing system does not contain a field for this information. He explained that, in the spirit of compromise and with the customers' interests top of mind, the Settling Parties stipulated and agreed that CEI South will collect data on residential customer housing types and analyze cost differentials between single- and multi-family residential customers. CEI South will also, in advance of its next rate case, offer to meet to discuss methodology and share initial results of its analysis with any interested party to this Cause. Pet. Ex. 19-S at 20-21.

IG witness York testified that the resolution of cost of service and rate design issues represents a reasonable resolution of the issues in dispute and is further consistent with the approved cost of service methodology that has been in place for CEI South for decades. IG Ex. 5 at 2-4.

ix. **<u>Settlement Opposition</u>.** CAC witness Inskeep opposed the rate design in the Settlement Agreement because it did not adopt his proposed Affordable Power Rider. CAC Ex. 6 at 19. Witness Barnes claimed that the Settlement assigns a greater portion of the revenue increase to the residential class than under CEI South's direct or rebuttal submission. CAC Ex. 7 at 6. He objected to the use of the 4CP for transmission costs and criticized the limitation of 1.35 times system average as not being a mitigation constraint but rather a result of the other revenue allocation parameters. He was critical of the Settlement for not addressing his concerns about Special Contract customers having cost trackers zeroed out without a corresponding increase to contract rates. He continued his recommendation for use of POD for production, CECA, and FAC, and energy and 4CP for ECA. He objected to exempting BAMP customers from production-related cost trackers He claimed that this provision would allow BAMP customers to be exempt from the Brown Securitization riders, which he claimed to violate the statute. He objected to providing a discount to BAMP customers in the rate for transmission service because SABIC had agreed to a cost-based rate when it elected to take BAMP service.

OUCC witness Dismukes had several similar objections to those raised by witness Barnes. He reiterated his concerns over allocation of production costs, restating his preferred allocation methodology set forth in his direct testimony. Pub. Ex. 12-S at 8-17. As to transmission plant allocation, he objected to using the 4CP method and argued that the originally proposed 12CP method was appropriate. He also objected to the use of CEI South's MSS for purposes of determining customer costs of the distribution system. He claimed the mitigation caps on revenue allocation increases were inconsistent with gradualism, and that the increase for any single customer class should be limited to 1.15 times the system average. As to rate design, he objected that the Settlement Agreement does not address the recovery of monthly TDSIC costs through fixed monthly charges, and he continued to recommend his proposed customer charges set forth in direct.

x. **<u>Settlement Rebuttal</u>.** Mr. Taylor testified that ultimately, OUCC witness Dismukes and CAC witness Barnes ignored the fact that the system must be built to meet a maximum demand, or peak load. He stated CEI South could not provide reliable service if it chose to only build capacity to support 90% of its peak load and customers expect to have access to electricity as reasonably close to 100% of the time as possible, necessitating the requirement of CEI South to build and invest in capital assets to meet this maximum demand to be placed on the system. Therefore, he opined the best method to accurately account for the respective customer classes' contribution to the need for the production assets is based on a demand-related allocation factor. That is, the demand a respective customer class places on the system at the time when the most capacity is needed. To that same end, the cost of the production assets is fixed in nature. There is no variability in their cost as they require large initial cash outlays. He stated demand is the correct measure of deriving the allocation of production assets to the customer classes. Pet. Ex. 18-SR at 3-4. Further, he testified as to why a change in the production plant allocation is not warranted at this time, stating there is no demonstrable evidence that CEI South's system has drastically changed from prior cases where its production assets were allocated on a demand basis.

As to the use of 4CP for transmission plant, Mr. Taylor testified CEI South's last rate case relied on the use of a 4CP allocation factor for transmission costs, whereas CEI South proposed in this case to move to a 12CP allocation. The continued use of the 4CP, rather than CEI South-proposed 12CP, was a settlement concession that conformed to the historical methodology approved for CEI South in prior rate cases. He noted that continuing to use a 4CP, rather than the proposed 12CP, only added approximately $1 million in costs or 0.3% to the residential class from what CEI South proposed in rebuttal testimony. By contrast, he explained the Industrial Group agreed not to use its MSS for distribution plant beyond transformers as proposed by witness York, which, if adopted, would have added $27 million or 7.7% to the residential allocation. This concession ($27 million) by the Industrial Group had far greater impact to the benefit of residential customers than retaining the 4CP for transmission was a detriment ($1 million). Pet. Ex. 18-SR at 6-7.

Mr. Taylor further supported the modest increase to the customer charge and he responded to the objections by witnesses Dismukes and Barnes regarding recovery of the TDSIC as a fixed charge. He reiterated his rebuttal testimony providing the reasons for why the OUCC's and CAC's recommendation to the TDSIC should be rejected. He stated the TDSIC is recovering fixed cost of transmission, distribution and storage, so it makes sense to recover the costs through a fixed charge. He opined that it is sound rate design practice to create this matching to the type of underlying cost. Furthermore, CEI South is proposing a TDSIC in a manner for which the Commission has currently approved. Pet. Ex. 18-SR at 10.

Witness Rice responded to Mr. Barnes's allegation that BAMP customers could illegally bypass the securitization charge. He explained that securitization charges are charged to BAMP customers today based on their auxiliary load, and in the proposed tariff, this is the base component of the rate. He further explained that the BAMP Base is the amount of power that a BAMP customer uses above and beyond what is covered by the customer's generating unit. The Securitization of Coal Plant is not applicable to the backup rate, which is supplied by the system when the BAMP customer's generator trips offline, not necessarily by CEI South's generators. He noted during a backup event, BAMP customers will be charged LMP for energy and CONE with overheads for capacity and no minimum charge is necessary for BAMP customers, as suggested by CAC. He claimed the Commission dismissed the same argument that customers would bypass the securitization charge in Cause No. 45722. Pet. Ex. 19-SR at 23.

Mr. Rice also responded to Mr. Inskeep's criticism that the Settlement Agreement does not contain his proposed Affordable Power Rider. He explained why no such rate was in the Settlement. The only occasion where the Commission considered a universal affordability tariff like that proposed by the CAC is the Indiana American Water decision in Cause No. 45870. That was a proposal under a statute that specifically allows for low-income programs (applicable only to water and wastewater). The Commission rejected the proposal and specifically noted its "role in addressing [affordability] is not to reach a conclusion as to whether the rates approved herein are 'affordable' for each and every customer." Separately, the only electric case where a utility made a similar proposal advocated by the CAC here is Northern Indiana Public Service Company, Cause No. 45772. Under NIPSCO's proposal, all customers would pay a monthly charge that would fund reduced electric bills for low-income customers. In that case, OUCC witness Paronish opposed the proposal and specifically testified "NIPSCO's low-income program proposal is essentially a tax, better left for the legislature to address." So unless there has been a recent change, he explained that he does not see how the CAC's proposed Affordable Power Rider could have been a term in a unanimous settlement. And even if such a term were included, he was uncertain whether it would be approved by the Commission. Pet. Ex. 19-SR at 5-6 and Attachment MAR-SR1.

Witness York rebutted the proposals by witness Dismukes and witness Barnes to include a substantial energy-based component in the allocation of production related costs as being contrary to cost causation principles, established Commission practice, and the longstanding regulatory treatment for CEI South's system specifically. IG Ex. 7 at 3. She pointed out the use of 4CP instead of 12CP was also consistent with the approved approach for CEI South's system dating back to the 1970s. In addition, she emphasized the significance of the Industrial Group's settlement concession not to utilize the MSS to apply a customer component to additional FERC accounts, which would have a much greater impact on residential rates.

Ms. York further rebutted the suggestions by witness Dismukes and witness Barnes advocating for greater mitigation for the benefit of the residential class. IG Ex. 7 at 5-6. She testified that mitigation measures are appropriate where strict adherence to cost of service would lead to major disparities in impact between classes, but it is important to recognize that basing rates on cost causation is a fundamental ratemaking principle. She noted CEI South's case-in-chief applied to 1.5 times system average parameter to limit the increase to the Water Heating class, but under the settlement the revenue spread falls within a tighter 1.35 times system-average tolerance. She described the OUCC and CAC positions as closer to an across-the-board approach, in derogation of cost of service results.

Regarding affordability, Ms. York noted the statutory affordability pillar applies across all rate classes and is not solely for the protection of the residential class. She further stated that rates must reflect the other four statutory pillars as well as affordability. She testified that the Settlement reasonably addresses affordability by reducing the proposed revenue increase by $38 million, removing most of CEI South's proposed increase to monthly customer charges, and instituting a number of customer protection provisions. IG Ex. 7 at 6-7.

Witness Coyle also rebutted the contentions regarding the BAMP terms. She explained BAMP customers have three components of service under the BAMP tariff: Base, Backup, and Maintenance Service. Base and Maintenance Service are both charged at the customer's Otherwise Applicable Rate Schedule and the BAMP customer is responsible for paying all trackers that apply to those rates. She explained that this means that all energy that is served as part of the Base and Maintenance Service are subject to all the trackers of CEI South, including the production related trackers. She stated that the only sales that are not subject to production-related trackers for the BAMP class is the energy that is delivered during a Backup Event when the customer-owned generator unexpectedly trips off-line. She noted that over the last three years SABIC experienced a Forced Outage Rate (FOR) between 1.3% and 2.1%, equating to Backup Events that are less than 8 days a year worth of energy at reduced level of capacity. In 2023, this resulted in less than $20,000 of associated revenues that CEI South would no longer collect from SABIC under the Settlement Agreement. Mr. Barnes' concerns regarding the potential impact to other customers are overstated considering the small amount of revenue at issue. She also responded to the allegation regarding alleged avoidance of the Securitization tariff. She explained that the BAMP tariff does subject customers in this class to a minimum bill provision, and payment of the securitization charges, as part of its Base and Maintenance Service. SABIC Ex. 2 at 4-5.

She also responded to the allegation from Mr. Barnes that the BAMP rate was less than cost, stating Backup Service customers are required to pay for transmission service at all hours for its full contracted load, even if its customer-owned generator is serving its load. SABIC's position in direct testimony was that Backup Service customers should pay based on its use of the transmission system; since Backup Service is different than full service customers, she proposed a probability weighted approach to ensure Backup Transmission Service charges contributed to the recovery of transmission costs. She noted the Settlement Agreement represents a compromise between CEI South and SABIC on this point and results in SABIC still paying higher than CEI South's FERC transmission rates, and the FERC rates represent the cost of transmission service for all other CEI South customers. She stated that the FERC transmission rate for CEI South for the year 2024 is $4.608/kW-month, which utilizes a forward-looking calculation that is equivalent to the estimated cost of service for the full year 2024 and includes prior period true-ups. The transmission cost of service agreed to in the Settlement agreement is above and beyond this value at $7.209/kW-month. SABIC Ex. 2 at 6-10.

xi. Commission Discussion and Findings. The Settlement Agreement resolves the disputed issues regarding cost of service and rate design among the Settling Parties. As explained below, we find that the resolution of these issues is balanced and achieves a fair result that is consistent with the objectives of achieving rates that are affordable and competitive across the rate class and with the public interest. We will set forth our findings on the individual issues in dispute below.

1. Production Costs. The dispute over the allocation of production costs was whether fixed production costs should be allocated on the basis of demand (either the 4CP or 12CP) or whether some portion of such costs should be allocated based on energy, through the CAC's proposed POD or the OUCC's proposed P&A. The Settlement continues with the allocation based on 4CP that has been in place for CEI South for many decades. We have long recognized that we are reticent to make significant changes in cost allocation. *CEI South*, Cause No. 43839, 289 PUR4th 9 (IURC 4/27/2011), 2011 WL 1690057. Just as in the last case, CEI South's system does not pass the three FERC tests which guide us as to whether the 12CP would be appropriate, and there has been nothing to show that CEI South's system demonstrates anything other than a summer peak. Furthermore, the OUCC and CAC are advocating a much more dramatic change – not a change between 4CP and 12CP but rather a change to a methodology that allocates most of CEI South's fixed production costs based upon energy. We have consistently rejected such proposals and concluded repeatedly that fixed production costs should be allocated based on demand, including for CEI South specifically. *See CEI South*, Cause No. 43839, at 58-65; *see also Duke Energy Indiana*, Cause No. 45253 (June 29, 2020), at 120. We do not find any change in circumstances that would support a departure from that established principle here.

2. Transmission Costs. CEI South initially proposed the use of 12CP to allocate for transmission costs, which is different from the allocation approved in its most recent case, and the OUCC and CAC supported that proposed change. IG and SABIC advocated for continued use of 4CP, which is the method used in the last case. Switching from 4CP to 12CP would have the effect of allocating 0.3% less, approximately $1 million in cost, to the residential class. The Settlement provides for a 4CP allocation for transmission costs, consistent with the last rate case.

We note that the use of 12CP, as proposed by CEI South before the Settlement was reached, better aligns with the MISO construct. While consistency is an important consideration, the passage of time since 2011 and treatment of other MISO utilities under the Commission's jurisdiction supports CEI South's proposal to use 12CP. By contrast, the use of 4CP, as proposed in the Settlement, favors large users such as the Settling Parties. After reviewing the evidence of record, the Settlement Agreement, and the revenue allocation adjustments directed in this Order, we accept the Settlement Agreement's 4CP allocation for transmission.

3. Distribution Costs. The limited MSS proposed by CEI South was opposed by multiple parties. However, none of the other parties demonstrated that the MSS approved in CEI South's last rate case has become unreasonable due to time or other factors. Accordingly, the Settlement Agreement's treatment of distribution cost allocation remains reasonable, and we approve it.

4. **<u>Accounts 911-912</u>.** After CEI South's agreement to keep DSM cost recovery out of base rates, the amount that remains in these accounts is slightly more than $1 million. We do not find that allocating them as customer-related or based upon total revenues makes a material enough overall difference to change our view of the Settlement. We accept witness Taylor's proposal to allocate these costs as customer related.

5. **<u>Section 24 Contracts</u>.** There are two issues with Section 24 contracts. The first is how such costs and revenues should be addressed in the preparation of a cost of service study. We find witness Taylor is correct that his study addresses such costs and revenues consistently with past practice and with the standard for actually approving these contracts in the first place. Section 24 contracts are approved in docketed cases, and we require evidence demonstrating: (1) the contract is necessary to attract or retain load; and (2) the cost recovery through the contract is sufficient to pay at least the marginal costs of service plus some recovery of fixed costs. *CEI South,* Cause No. 45773 (Feb. 8, 2023), at 5. This means all other customers benefit from approval of the contract because the fixed cost recovery (and therefore rates) will be lower than it would be had the contract not been approved. *See Local Union 204 v. Public Serv. Co.*, 524 N.E.2d 318, 319 (Ind. 1988). The other issue is CAC's objection that the Section 24 base rates are not being increased when trackers paid by Section 24 customers are zeroed out. This contention fails to recognize that these are contractual arrangements that we have already approved. To do as the CAC suggests would be to modify those previously approved contracts which we had already found were necessary to attract or retain the load. This would deviate from the approved terms and would have a chilling effect on economic development, and we decline to take this step.

6. **<u>Customer Charge and TDSIC as Fixed Residential Charge</u>.** Much of the dispute over the customer charge in base rates has been resolved by the agreement to an extremely limited increase (back to the level before the repeal of the Utility Receipts Tax). We reject the arguments from the CAC and the OUCC that the fixed charge should only include metering and billing costs. This is inconsistent with our prior findings. *See IPL,* Cause Nos. 44575 and 44602, at 72. Furthermore, we are persuaded by witness Taylor's evidence that frequently low-income customers are harmed by recovery of fixed costs through a volumetric charge. We are further persuaded that the TDSIC distribution costs should continue to be recovered through a fixed charge. These are fixed costs, and recovery through a volumetric charge would send inefficient price signals and would work to the detriment of those low-income customers who are higher volume users.

7. **<u>Affordable Power Rider</u>.** CAC witness Inskeep's proposal for an Affordable Power Rider presents a novel approach to affordability. As we have said previously, however, responding to a proposal for some form of low-income rates in the context of filing rebuttal testimony in a base rate case is not how such a program should be developed and presented to the Commission. *IPL,* pp. 67-68. There are many details that would need to be worked out to design and present a low-income program. *See Indiana American Water Co.*, Cause No. 45870, (Feb. 14, 2024), at 122-125. As we found in connection with a NIPSCO proposal, the development of a low-income program that could be considered and ultimately approved by this Commission would greatly benefit from consensus among the stakeholders. *Northern Ind. Pub. Serv. Co.*, Cause No. 44688 (July 18, 2016), at 90.

8. **<u>Trackers</u>.**

A. <u>MCRA</u>. CEI South's proposal was to allocate the MCRA in the same manner as transmission costs. Based on the evidence of record, we approve the allocation based upon 4CP. We reject the CAC's argument otherwise.

B. <u>ECA</u>. With respect to the recovery of CCR remediation costs through the ECA, the CAC contends that since coal ash is generated through the production of energy, the costs of remediation should be based upon energy. We note in CEI South's most recent coal ash pond compliance case, we explained that there are two methods of recovery of the costs of CCR. One is through federal mandate proceedings; the other and more traditional method is to treat CCR costs as cost of removal – debiting Account 108 as the costs are incurred and reflecting projected and past costs (though the debit to Account 108) in the calculation of depreciation accrual rates. *CEI South*, Cause No. 45903, at 10-11. There is no dispute that depreciation expense and accumulated depreciation should be allocated the same as the underlying plant. Pet. Ex. 18 at 15. Thus, if CCR costs were recovered through this more traditional method, they would not be recovered on an energy basis. We fail to see how the method of recovery (ECA or base rates) could impact cost causation. As such, we reject the CAC's proposal to allocate the CCR costs recovered through the ECA on an energy basis.

C. <u>CECA</u>. Given our approval of the 4CP for production-related costs, we reject the CAC's proposal to allocate the CECA on the POD methodology.

D. <u>FAC</u>. Two FAC proposals were made that are either moot or have been withdrawn. Mr. Rice noted in his direct testimony CEI South's proposed allocation of the pipeline demand costs that were the subject of Cause No. 45564-S1. Since the Commission resolved the rate design issues in the FAC related to this subject in that subdocket, the issue in this rate case is now moot. In addition, the IG requested that the FAC should be modified to recognize the capacity component of renewable resource costs. That request has been withdrawn as a result of the Settlement.

E. <u>Revenue Allocation</u>. The only material dispute over revenue allocation was the mitigation factor to put on the rate increases for individual classes. Other than water heating, the Settlement caps the increase at 1.35 times the system average. The OUCC proposed to limit any class increase to 1.15 times the system average, while the CAC proposed 1.20 times the system average.

After reviewing the evidence of record, we reject the Settlement Agreement's proposal to cap the increase (for all classes other than water heating) at 1.35 times the system average and accept the OUCC's proposal to limit any class increase to 1.15 times the system average, to minimize rate shock to consumers. The high volume of consumer comments received in this case, in addition to the nine-hour field hearing held in Evansville on February 29, 2024, indicates how significant of a concern affordability is to CEI South's residential customers, a concern we take very seriously.

The Settling Parties' agreement to cap the increase at 1.35 times the system average results in an increase to residential customer rates of 14.66%, or $46.8 million. Adopting the OUCC's position of 1.15 times the system average reduces this residential rate increase to 12.71%, or $40.6 million, saving residential ratepayers $6.2 million.

On rebuttal, CEI South identified a 1.22 times the system average overall increase for the residential class. While we find above that the choice of 4CP over 12CP is acceptable in the context of the overall settlement, this choice is nonetheless a revenue requirement disadvantage to the residential class. The Settlement Agreement's rate increase cap at 1.35 times the system average highlights the impact of this disadvantage. Affordability is a key consideration across all customer classes, and the desire to provide affordability across the board supports a revenue requirement increase that is as evenly borne as practical, while considering any subsidies that may be identified by the ACOSS. The ACOSS in this proceeding identifies that the interclass subsidies are materially different than those in recent ACOSS seen in other cases. *See e.g., Duke Energy Ind., Inc.,* Cause No. 46038 (Jan. 29, 2025). Accordingly, we find that limiting the residential class increase to 1.15 times the system average is consistent with affordability across all classes in the context of reasonably allocating CEI South's authorized revenue requirement increase.

F. **BAMP.** Before the Settlement Agreement, there was considerable dispute between CEI South and SABIC regarding the BAMP rate. We find that the Settlement, which produces a rate that is 95% of the cost of BAMP service as calculated by CEI South is a reasonable resolution of that dispute. As noted, under Ms. Coyle's presentation, the cost of service would be much lower. We reject CAC's argument that the BAMP rate allows a bypass of the Securitization Charge. Securitization Charges are to be "payable by all customers and customer classes." Ind. Code § 8-1-40.5-12(b). There is no requirement that each individual rate paid by a customer is subject to the Securitization Charge. It is undisputed that SABIC is subject to and cannot bypass the Securitization Charge and so we reject CAC's argument otherwise.

N. Miscellaneous Fees and Charges.

i. **CAC's Position.** CAC witness Inskeep made several recommendations regarding miscellaneous charges and fees. He requested that CEI South's late payment charge be eliminated. He recommended that reconnection charges be eliminated or reduced. Finally, he recommended that per-transaction charges assessed by third parties for processing payments be eliminated for the customer by rolling the costs into CEI South's revenue requirement. CAC Ex. 2 at 10. He noted CEI South is proposing to reduce its reconnection charge, and to reduce it $5 if the proposed ARP that would allow remote disconnection is approved. He further objected to the higher reconnection charge for after-hours reconnection. CAC Ex. 1 at 79-80. The convenience fees he was referencing were credit card fees, kiosk payments, plus other fees associated with walk-ins at local businesses. The total amount of such fees during the base year was $810,740, and Mr. Inskeep recommended that this amount be included in the revenue requirement. CAC Ex. 2 at 82. Finally, he noted that 170 IAC 4-1-13(c) allows a utility to assess a late payment charge but it is not required to do so. He recommended that the Commission order CEI South to eliminate or reduce late payment charges. CAC Ex. 2 at 82.

ii. CEI South's Rebuttal. CEI South witness Folz testified that there are costs incurred with reconnection and even though they will be less with remote disconnection, there are still costs. Pet. Ex. 5-R at 13. Mr. Rice noted that this Commission has twice previously rejected the proposal to eliminate the imposition of third-party convenience fees by including such costs in the revenue requirement. Pet. Ex. 19-R at 53.

iii. Settlement Opposition. Mr. Inskeep objected to the Settlement Agreement because it does not adopt his proposal for convenience fees. He also objected that the late payment fee was only to be waived once per year and upon request. He further continued to object to the imposition of any reconnection fee with remote disconnection. CAC Ex. 4 at 22.

iv. Commission Discussion and Findings. We find the Settlement Agreement strikes the appropriate balance in addressing the miscellaneous charges discussed by Mr. Inskeep. For the majority of CEI South's residential customer base, this issue has become largely moot from our approval of the ARP. The fee for reconnection is $3. Despite Mr. Inskeep's protestations, there are administrative tasks as explained by witness Folz to perform a reconnection. The cost is not zero. As to Mr. Inskeep's position on convenience fees, we have twice rejected similar proposals and see no reason to change our view today.[23] Finally, our promulgated rules allow electric utilities to impose a fee for late payment and provides for the calculation. 170 IAC 4-1-13(c). After reviewing the evidence of record, we find that no compelling reason exists to impose on CEI South any further restrictions on late payment fees than those to which it has voluntarily agreed in the Settlement Agreement.

8. Overall Reasonableness of the Settlement Agreement. Settlements presented to the Commission are not ordinary contracts between private parties. *United States Gypsum, Inc. v. Indiana 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 Coalition v. PSI Energy*, 664 N.E.2d 401,406 (Ind. Ct. App. 1996)). Thus, the Commission "may not accept a settlement merely because the private parties are satisfied; rather [the Commission] must consider whether the public interest will be served by accepting the settlement. *Citizens Action Coalition*, 664 N.E.2d at 406. Furthermore, any Commission decision, ruling, or order, including the approval of a settlement, must be supported by specific findings of fact and sufficient evidence. *United States Gypsum*, 735 N.E.2d at 795 (citing *Citizens Action Coalition v. Public Service Co.*, 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 it is reasonable, just, and consistent with the purpose of Ind. Code § 8-1-2-1 *et seq.*, and that such agreement serves the public interest.

The Commission has before it substantial evidence from which to determine the reasonableness of the terms of the Settlement Agreement. All parties had an opportunity to participate in and monitor the settlement negotiations. Because the Settlement Agreement is not unanimous, we must address the outstanding concerns raised by the non-settling parties that have

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[23] *Indiana American Water Co.*, Cause No. 45870 (Feb. 14, 2024); *Duke Energy Indiana*, Cause No. 45253 (June 29, 2020).

not been addressed elsewhere in this order. The OUCC and CAC voiced concerns related to affordability and reliability in support of their opposition to the Settlement Agreement. As discussed below, we find the evidence of record supports approval of the Settlement Agreement as a reasonable resolution of the issues affecting each of these concerns.

A. <u>OUCC and CAC Position</u>. In addition to the specific issues raised and discussed in detail above, the OUCC and CAC also challenged CEI South's proposed rate increase, as modified by the Settlement Agreement, on the basis of affordability. They also claimed that CEI South has shortcomings in reliability.

In defining affordability, OUCC witness Dismukes discussed the concept of energy burden, referring to the amount of household income that is used to pay for one's electric bill. He stated energy burden becomes unaffordable when the percentage of income spent on energy exceeds 6%.[24] He presented an analysis of residential Energy Affordability Index estimates at both the 15th and 20th income percentiles. In his testimony in opposition to the Settlement, Dr. Dismukes disagreed with CEI South's claims that its rates are below the 6% affordability threshold he presented in his direct testimony. Pub. Ex. 12-S at 5-8. He said CEI South's analysis was flawed insofar as it assesses the affordability of CEI South's rates to the median household instead of examining affordability for low- and moderate-income households. He presented an updated analysis using the 15th and 20th percentile of household incomes in each of the seven counties CEI South operates in. His updated analysis showed that for households earning at the 15th percentile, CEI South's rates currently exceed or will exceed the 6% affordability level in all but one county and for households in the 20th percentile income level the rates currently exceed or will exceed the 6% energy burden in three of the counties. He characterized the 6% threshold as representing a level of "extreme financial burden."

CAC witness Inskeep criticized CEI South for not having performed a bill affordability analysis. CAC Ex. 2 at 18. He initially recommended the Commission adopt the following in the name of affordability: dismissal of the case, a mandated freeze or curtailment on spending and investments, a management audit, disallowance of a return of or on plant that is not in the public interest or resulting in just and reasonable rates, additional adjustments to remove a portion of management employee compensation, and additional downward adjustments to ROE. He claimed the considerations CEI South described to address affordability do not actually help customer affordability or reflect misleading framing by CEI South. He also said even if they were valid affordability considerations, they were not sufficient to address affordability. He presented his own analysis and concluded many of CEI South's customers who are at or near the Federal poverty level have electricity burdens well above 6% and even higher energy burdens. He said even the median household in Evansville would exceed the threshold for a high energy burden after giving effect to CEI South's initial proposed rate increase. He proposed an Affordable Power Rider to assist low-income customers. In his testimony in opposition to the Settlement, Mr. Inskeep updated his energy burden analysis to reflect the impact of the Settlement Agreement and to update CEI South gas rates for current rates in effect as of July 2024. While median households in Evansville

[24] Dr. Dismukes cites Fisher, Sheehan, and Colton's Home Energy Affordability Gap Study from 2011 and "understanding Energy Affordability" ACEEE, 2015, page 2. Pub. Ex. 12 at 8 and n.9.

under his revised analysis have an energy burden of nearly 6%, low-income households continue to have energy burdens higher than the 6% threshold. CAC Ex. 6 at 7-8.

OUCC witness Eckert claimed that CEI South has not shown improved reliability over the last five years. Pub. Ex. 1 at 16-17. CAC witness Inskeep claimed CEI South's reliability has gotten worse over time, despite significant investments through its approved TDSIC plans. CAC Ex. 2 at 42.

B. __CEI South's Position__. Mr. Leger described the many actions CEI South has taken for affordability purposes, beginning with securitization and including several affordability considerations incorporated into its requested relief in this Cause. Pet. Ex. 1 at 14-15. He also stated CEI South partners with a variety of organizations to offer programs to assist qualifying individuals. He explained CEI South offers customers the ability to set a preferred billing date if a customer prefers receiving their bill at a particular time of the month. CEI South also offers budget billing to reduce large bill increases during periods of higher electric use. Payment plans are also available to CEI South customers individually if they fall behind on bill payments. Income eligible customers may also apply for the Energy Assistance Program through their local Community Action Agency. Additionally he stated, CEI South partnered with the City of Evansville, local assistance agencies, and township trustee offices to host a series of access to service fairs throughout the winter season. Participants can speak one-on-one with a customer service representative for bill assistance and general questions about their bill or service.

Mr. Rice presented direct testimony showing that since CEI South's last rate case decided in 2011, CEI South has endeavored to keep customer bills from rising too quickly, even with the addition of rate adjustment mechanisms. He showed that customer bills have remained relatively flat, below inflation levels since 2011. Pet. Ex. 19 at 4. He noted the significant positive impact CEI South's pursuit of securitization has had on affordability for customers.

On rebuttal, Mr. Leger took issues with Mr. Inskeep's insinuation that CEI South's rate case disregards affordability. He noted that Mr. Rice presents a compound annual growth rate calculation highlighting the fact that CEI South has grown residential bills at less than 0.5% per year on average in that timeframe, which is far less than any other utility in the State of Indiana, thereby highlighting CEI South's commitment to affordability for its customers. Pet. Ex. 1-R at 3-4. Mr. Rice responded to the affordability arguments raised by the parties as well as concerns voiced at the field hearing in both his rebuttal and his settlement rebuttal. He described the difficulties inherent in addressing affordability, which does not lend itself to the same examination through modeling, spreadsheets, and statutory parameters as the other four pillars. Pet. Ex. 19-R at 3.

In his Settlement rebuttal, CEI South witness Rice reiterated that the affordability pillar is concerned with retail electric utility service being "affordable and competitive across residential, commercial, and industrial classes." Pet. Ex. 19-SR at 7. He explained all customer classes saw a drop in the proposed increase because of the Settlement Agreement. Mr. Rice testified that all Indiana electric public utilities are in the midst of significant generation transition, causing significant upward pressure on rates well into the future as none of them has completed the transition to cleaner resources. Mr. Rice presented a comparison to other electric utilities in the State based on the IURC's 2024 Residential Bill Survey, showing CEI South's residential electric bill is not the highest in the state and that between 2011 and 2024, CEI South's rates have increased the least among its peers in terms of dollars, percentage change, and rate of change. He explained it also does not fully reflect the effects of the recent I&M rate case order, nor does it reflect the outcome in the pending Duke Energy Indiana rate case or the termination of temporary credits providing refunds resulting from appeals of Commission orders. He stated that at this point it would be incorrect to imply that following approval of the Settlement Agreement in this case that CEI South's rates will be out of line when compared to other utilities in Indiana. His analysis showed a 2.1% compound average growth rate between rate cases, which is a strong demonstration of affordability and illustrates how prudent CEI South has been in making investment decisions and managing necessary expenses on behalf of its customers to provide safe and reliable service since that time.

Regarding the energy burden of the electric portion for CEI South customers, Mr. Rice presented evidence that, at settled rates, the energy burden for the average CEI South customer in Vanderburgh County has dropped. Moreover, incomes have risen in Vanderburgh County and the City of Evansville with inflation, and should continue to do so, helping to dampen the effect of necessary rate increases. Mr. Rice responded to Mr. Inskeep's updated analysis as well. He stated it is important to reiterate that none of the parties know the income of individual customers, the level of assistance that they may receive, or the number of people in the household. He explained it is also important to note that a family of three with a yearly income of $48,064 or less in the past 12 months is likely to qualify for Energy Assistance through the Community Action Program of Evansville. Specifically, 150% of poverty is a level the federal government and state government have recognized as having affordability challenges. Mr. Rice noted that Dr. Dismukes's updated affordability analysis now shows the 20th percentile household income in the total CEI South service territory is currently under the 6% threshold that he once called "affordable," and it remains under the 6% threshold in 2026 at 5.8%. He explained OUCC witness Dismukes's analysis now shows that customers with a 15th percentile household income in the total CEI South service territory have energy burdens of 7.3%. Mr. Rice testified that he still believes that affordability is difficult to measure and dependent on an individual customer's circumstances. Nevertheless, he stated he stands behind the methodology CEI South presented in rebuttal and settlement as a reasonable view of affordability.

CEI South witness Rawlinson provided testimony explaining that Mr. Eckert has not appropriately correlated TDSIC investment impacts to CEI South's reliability indices, explaining that TDSIC investments do not directly target all outage causes and Mr. Eckert's analysis does not account for external factors such as weather. Pet. Ex. 4-R at 4-5. Moreover, without the investments CEI South made in its first TDSIC Plan (Cause No. 44910) and the investments currently planned in CEI South's second TDSIC Plan (Cause No. 45894), Mr. Rawlinson stated CEI South's reliability performance would have declined. He described CEI South's experience as a result of a severe weather event on April 2, 2024 involving multiple tornados. He said the investments CEI South made through its TDSIC Plans reduced the time required to restore service to CEI South's customers. In Settlement rebuttal, Mr. Rice reiterated that CEI South's capital investments cannot control the weather or prevent a tree from falling into the line or prevent someone from driving into the utility's poles. Mr. Eckert's and Mr. Inskeep's selective use of different time periods do not change Mr. Rawlinson's findings that without these investments, CEI South's reliability would suffer. Pet. Ex. 19-SR, Attachment MAR-SR2 at 1.

C. Commission Discussion and Findings. This case offers the opportunity for the Commission to address the myriad concerns over affordability we have heard throughout this case. Our approval of the Settlement Agreement, which substantially reduces the requested relief in service of affordability, while upholding the tenets of reliability, resiliency, stability and environmental sustainability, represents the constant balancing this Commission has been charged to perform by the Indiana General Assembly.

While arguments were raised by the OUCC and CAC claiming CEI South has not shown improvements in reliability, the record reflects that Petitioner's investments in its transmission and distribution system have been critical to maintaining reliability, particularly when events outside of CEI South's control occur, such as extreme weather events like those experienced in CEI South's service territory in April 2024. The appropriate benchmark must consider these unique events. CEI South's TDSIC investments have improved reliability, all else being equal.

The record reflects efforts undertaken by CEI South to tackle the problem of affordability for its customers. Pet. Ex. 1 at 4; Pet. Ex. 19 at 4-9. These include a multi-phase approach to rate implementation to achieve gradualism in rate increases, a settled ROE considerably below that recommended by CEI South's expert, utilization of the Average Service Life depreciation rates lowering the revenue requirement by approximately $12.5 million despite CEI South's expert's recommendation to use the Equal Life Group, extended amortization periods for recovery of the 20% deferred from TDSIC and ECA and the proposal that 100% of sales margins from the Wholesale Power Market off system sales be credited to customers, and the proposed interim phases when Posey Solar and the CT Project are placed in service, creating savings from avoided incremental PISCC and deferred depreciation. Pet. Ex. 1 at 4, 15; Pet. Ex. 19 at 4-9. Moreover, Petitioner was involved in advocating for legislation authorizing the first ever utility asset securitization in Indiana, allowing for the issuance of securitization bonds at a lower long-term debt cost for the remaining value of the now retired A.B. Brown coal units 1 and 2 for net present value savings of $53 million versus traditional ratemaking. Pet. Ex. 1 at 14; Pet. Ex. 19 at 4-5.

All of these efforts culminated in a Settlement, albeit non-unanimous, that saw a $35 million further decrease in CEI South's request coupled with concessions on numerous other issues including lowering the fixed residential customer charge from approximately $23 to the pre-IURT repeal level of $11, elimination of pre-test year Phase 1 rates, and reducing or eliminating reconnection and late payment charges in certain circumstances. Pet. Ex. 19-SR at 6. The Settlement Agreement also incorporates several customer protection terms that had been acceptable to the OUCC and CAC in other settlements and approved by the Commission as in the public interest. The evidence also reflects that CEI South's rates since its last general rate case have grown at a much slower pace than those of its peers, and the proposed rates from Settlement are in line with where other electric utilities in the state currently are or are likely headed in the near term. Despite CEI South's rate mitigation efforts and the Settling Parties' compromise on issues benefiting residential customers, the resulting proposed rate increase is still being opposed by the OUCC and CAC.

The OUCC and the CAC challenged the Settlement Agreement largely on the basis that the Settling Parties (other than the Petitioner) are large-usage customers and therefore, they contend, the Settlement Agreement does not benefit other customer classes. As discussed in Paragraph 7.M (Cost of Service and Rate Design; Multi-Family Rates; BAMP), we do not accept this characterization. With the totality of the evidence in mind, we find that the terms of the Settlement, with the modification to the revenue allocation discussed above to further address affordability by limiting the residential customer class increase given the Settling Parties' agreement to use 4CP, are reasonable and beneficial in the provision of electric service to all CEI South ratepayers. This Commission has not lost sight of the testimony of hundreds of witnesses at the public field hearings and recognizes that even moderated rate increases can be difficult on customers. As Mr. Gorman testified, as to revenue issues, the Industrial Group and SABIC had every motivation and made every effort to obtain as favorable an outcome as possible, because the cost of electricity is a large component of their cost of doing business. The negotiated revenue concessions operate to the benefit of all rate classes, not just industrial customers. Notably, the settled result, at $80.0 million, is significantly below the Industrial Group's litigation position. The $80.0 million is closer to the OUCC's litigation position than CEI South's rebuttal case, reflecting a concession on CEI South's part that crosses the midpoint of the range of potential litigation outcomes. IG Ex. 6 at 6; Pet. Ex. 19-SR at 3. While the Commission appreciates that affordability will remain a concern for CEI South's customers, this is not a reason to entirely reject the Settlement Agreement which substantially reduces the impact of CEI South's requested relief for all customers. We recognize that our role in addressing affordability cannot be "to reach a conclusion as to whether the rates approved herein are 'affordable' for each and every customer." *Indiana-American Water Co.*, Cause No. 45870 (Feb. 14, 2024), at 105.

D. <u>Ultimate Findings Approving Settlement</u>. We are not persuaded by either the OUCC or the CAC that the Settlement Agreement should not be found to be in the public interest. We have recited the benefits flowing to all customers from the terms of the Settlement Agreement. When taken as a whole, the Settlement as modified herein is a reasonable resolution to the issues raised in this proceeding and represents a fair balance between the needs of CEI South and the interests of customers. The Settlement Agreement as modified results in a reasonable revenue increase which reflects a fair return of and on capital investment made by CEI South if the utility is operated efficiently and enables CEI South to continue to provide reliable service to its customers on a sound financial foundation.

Based upon our review of the record, the Commission finds that the Settlement Agreement is within the range of potential outcomes and as modified represents a fair, just, and reasonable resolution of the issues within the guardrails of the Five Pillars statutory construct. The Commission further finds and concludes that the Settlement as modified herein is reasonable, supported by substantial evidence, and in the public interest. Accordingly, the Settlement Agreement is approved, with the exception of the revenue allocation, as discussed above.

9. <u>Overall Authorized Increase</u>. Having found, based on the evidence of record, that the Settlement Agreement should be approved with modification. The proposed revenue increase is based upon a projected test year ending net original cost rate base of $2,769,851,666 as shown on Appendix A to the Settlement Agreement (Schedule B-1 of Petitioner's Exhibit No. 21-S), as follows:

Rate Base as of December 31, 2025

1	Plant In Service	$	3,903,197,879
2	Reserve for Accumulated Depreciation	$	(1,227,581,792)
3	Net Plant in Service	$	2,675,616,087
4	Other Items:		
5	Fuel Stock	$	8,990,701
6	Utility Material & Supplies	$	41,360,961
7	Allowance Inventory	$	-
8	Stores Expense	$	311,332
9	PISCC - AMI	$	10,585,830
10	PISCC - TDSIC 1.0	$	16,517,144
11	PISCC - TDSIC 2.0	$	5,433,980
12	PISCC - CECA	$	2,963,459
13	PISCC - ECA	$	2,863,643
14	PISCC - ECA FB Culley East Ash Pond	$	2,712,341
15	PISCC - CT	$	2,496,186
	Jurisdictional Rate Base	$	2,769,851,666

We further find that a fair return should be authorized based upon this net original cost rate base and a projected weighted average cost of capital of 6.77%, as shown on Appendix A to the Settlement Agreement (Schedule D-1 of Petitioner's Exhibit No. 21-S), as follows:

Capital Structure as of December 31, 2025

	Class of Capital	Amount ($000)	Percent	Cost	Weighted Cost
1	Long-Term Debt	$ 1,294,210	39.49%	5.12%	2.02%
2	Preferred Stock	$ -	0.00%	0.00%	0.00%
3	Common Equity	$ 1,582,041	48.28%	9.80%	4.73%
4	Cost Free Capital	$ 390,113	11.90%	0.00%	0.00%
5	Other Capital	$ 10,754	0.33%	5.87%	0.02%
	Total Capital	$ 3,277,119	100.00%		6.77%

We therefore find that CEI South should be authorized to increase its base rates and charges in multiple steps, calculated to produce additional annual base rate revenue of $80,009,617, total base rate revenue of $803,932,466, and total net operating income of $187,518,958, as shown on Appendix A to the Settlement Agreement (Schedule A-1 of Petitioner's Exhibit No. 21-S), as follows:

1	Original Cost Rate Base	$	2,769,851,666
2	Weighted Average Cost of Capital		6.77%
3	Net Operating Income Required	$	187,518,958
4	Net Operating Income at Pro forma Present Rates	$	117,233,544
5	Net Revenue Increase Required	$	70,285,414
6	Gross Revenue Conversion Factor		1.3370172
7	Gross Revenue Increase Required	$	93,972,808
8	Less: Fuel & Purchased Power Expense Reduction	$	(13,963,191)
9	Recommended Gross Revenue Increase Required Less Fuel & Purchased Power Expense Reduction	$	80,009,617

The rate increase authorized herein should be implemented in multiple steps as delineated in Paragraph 7.B (Phased Rate Implementation) above.

Section B.15.b of the Settlement Agreement provides that any matters not addressed by the Settlement Agreement will be adopted as proposed and supported by CEI South's case-in-chief, as modified in its rebuttal testimony. This includes all the relief summarized in Paragraphs 7 (Settlement) and 8 (Overall Reasonableness of the Settlement Agreement) of this Order, which has not otherwise been modified by the Settlement Agreement. The Commission finds Section B.15.b of the Settlement Agreement to be reasonable and it is approved with the entirety of the Settlement Agreement.

10. <u>Effect of Settlement Agreement</u>. The Settlement Agreement is not to be used as precedent in any other proceeding or for any other purpose except to the extent necessary to implement or enforce its terms; consequently, with regard to future citation of the Settlement Agreement or of this order, we find our approval herein should be treated in a manner consistent with our finding in *Richmond Power & Light*, Cause No. 40434, 1997 WL 34880849 at *7-8 (March 19, 1997).

11. <u>Confidentiality</u>. CEI South filed motions for protection and nondisclosure of confidential and proprietary information on December 5, 2023, March 28, 2024, and April 4, 2024, April 9, 2024. The OUCC filed a motion for protection and nondisclosure of confidential and proprietary information on March 12, 2024. The Industrial Group filed motions for protection and nondisclosure of confidential and proprietary information on March 12, 2024 and March 14, 2024. Each motion was supported by affidavits showing certain documents to be submitted to the Commission contain confidential trade secrets as defined under Ind. Code § 23-2-3-2. Docket entries were issued on each of these motions finding such information to be entitled to confidential treatment on a preliminarily basis, after which the information was submitted under seal. The

Commission finds all such information granted preliminary confidential treatment is confidential under Ind. Code §§ 5-14-3-4 and 8-1-2-29, is exempt from public access and disclosure by Indiana law and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

12. OUCC's Motion to Strike. On April 22, 2024, the OUCC filed a Motion to Strike certain rebuttal testimony and attachments filed by Petitioner as inadmissible hearsay that falls within no exception. Petitioner filed a response to the Motion to Strike on April 25, 2024, arguing that the identified reference to testimony in another rate case was not offered for the truth of the matter asserted. The OUCC filed a reply in support of the Motion to Strike on April 29, 2024, reiterating the arguments made in the Motion to Strike.

After reviewing the Motion to Strike, Response, and Reply, we deny the Motion to Strike. As the OUCC itself notes, the Commission may rely on hearsay, though it may not use it as the sole basis for its decision. As should be clear from this Order, the evidence that is the subject of the Motion to Strike was not used as the sole basis for our decision in this Cause, so this issue is moot.

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 in its entirety except as noted in this Order.

2. There shall be a cap limiting any class rate increase (other than for water heating customers) to 1.15 times the system average.

3. Petitioner's ARP for waiver from 170 IAC 4-1-16(f) for remote disconnections as modified pursuant to Sections B.9 and B.10 of the Settlement Agreement is approved as described in Findings Paragraph 7.K (ARP for Remote Disconnection).

4. Petitioner is authorized to increase its rates and charges for electric utility service in multiple steps as described in Findings Paragraph 7.B (Phased Rate Implementation).

5. New depreciation rates applicable to CEI South's common and electric plant are approved as explained in Findings Paragraph 7.F (Depreciation Rates and Amortization).

6. Petitioner shall file under this Cause for approval by the Commission's Energy Division the new schedules of rates and charges along with its revised tariff consistent with the Settlement Agreement and the rates and charges approved in this order.

7. The rates and charges for Steps 1 and 2 shall be implemented upon approval of the filed tariffs on a service-rendered basis.

8. Petitioner shall certify its net plant, original cost rate base, and capital structure on December 31, 2024 (Settlement Phase 1) and December 31, 2025 (Settlement Phase 2) and calculate the resulting rates and charges, which shall be made effective upon filing and approval of the Commission's Energy Division in accordance with the findings herein, subject to being

contested and trued-up consistent with the Settlement Agreement.

9. To the extent that either Posey Solar or the CT Project is not completely in service as of December 31, 2024 but is in service before December 31, 2025, Petitioner is authorized to implement additional interim phases to its increase as described above (Phased Rate Implementation).

10. Petitioner's proposed CPP Pilot, Rider ADR, and Rider GE are approved as contemplated by the Settlement Agreement.

11. Petitioner is directed to file under this Cause all information required by the Settlement Agreement.

12. The information filed in this Cause pursuant to motions for protection and nondisclosure of confidential and proprietary information is deemed confidential under Ind. Code § 5-14-3-4, 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.

13. This order shall be effective on and after the date of its approval.

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

APPROVED: FEB 03 2025

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

Regina K. Joyner Digitally signed by Regina K. Joyner
Date: 2025.02.03 13:08:55 -05'00'
______________________________ **on behalf of**

Dana Kosco
Secretary of the Commission

OFFICIAL EXHIBITS

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A CENTERPOINT ENERGY INDIANA SOUTH ("CEI SOUTH") FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A PHASE-IN OF RATES, (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, AND NEW AND REVISED RIDERS, INCLUDING BUT NOT LIMITED TO A NEW TAX ADJUSTMENT RIDER AND A NEW GREEN POWER RIDER (3) APPROVAL OF A CRITICAL PEAK PRICING ("CPP") PILOT PROGRAM, (4) APPROVAL OF REVISED DEPRECIATION RATES APPLICABLE TO ELECTRIC AND COMMON PLANT IN SERVICE, (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING RELIEF, INCLUDING AUTHORITY TO CAPITALIZE AS RATE BASE ALL CLOUD COMPUTING COSTS AND DEFER TO A REGULATORY ASSET AMOUNTS NOT ALREADY INCLUDED IN BASE RATES THAT ARE INCURRED FOR THIRD-PARTY CLOUD COMPUTING ARRANGEMENTS, AND (6) APPROVAL OF AN ALTERNATIVE REGULATORY PLAN GRANTING CEI SOUTH A WAIVER FROM 170 IAC 4-1-16(f) TO ALLOW FOR REMOTE DISCONNECTION FOR NON-PAYMENT.	) **CAUSE NO. 45990**

IURC JOINT - Settling Parties
EXHIBIT No. 1
9-10-24 LR
DATE REPORTER

<u>STIPULATION AND SETTLEMENT AGREEMENT</u>

This Stipulation and Settlement Agreement (the "Settlement Agreement") is entered into by and among Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South" or the "Company"), the CenterPoint Energy Indiana South Industrial Group[1] ("Industrial Group") and SABIC Innovative

[1] The Industrial Group is a collection of industrial energy consumers, to include the following: Consolidated Grain & Barge; CountryMark Refining and Logistics, LLC; Marathon Petroleum Company; and Toyota Motor Manufacturing of Indiana, Inc.

Plastics Mt. Vernon, LLC ("SABIC") (collectively, the "Settling Parties"). The Settling Parties, solely for purposes of compromise and settlement, stipulate and agree that the terms and conditions set forth in this Settlement Agreement represent a fair, just, and reasonable resolution of all matters raised in this proceeding, subject to their incorporation by the Indiana Utility Regulatory Commission ("Commission") into a final, non-appealable order without modification or further condition that is unacceptable to any Settling Party. The Settling Parties agree that this Settlement Agreement resolves all disputes, claims and issues arising from the electric rate case proceeding currently pending in Cause No. 45990 as between the Settling Parties. The Settling Parties agree that matters for which CEI South requested relief in this Cause as adjusted on rebuttal that are not addressed herein but were expressly supported by CEI South's evidence should be granted as proposed, without waiving the right of any party to litigate such issues in future proceedings.

A. Background.

1. <u>CEI South's Current Rates and Charges</u>.

a. <u>Base Rates and Charges</u>. CEI South's existing base rates and charges for electric utility service were established in its thirty-day filing #50171, effective June 1, 2018, pursuant to the Commission's February 16, 2018 Order in Cause No. 45032, its investigation into the impacts on Indiana utilities and customers resulting from the December 22, 2017 Tax Cuts and Jobs Act of 2017 ("TCJA"), as further reduced in Petitioner's 30-day filing #50548, effective July 1, 2022, to give effect to the repeal of the Utility Receipts Tax. The rates approved effective June 1, 2018 and July 1, 2022, reduced

CEI South's existing base rates and charges for electric utility service established in its most recent retail base rate case order issued on April 27, 2011, in Cause No. 43839.

b. FAC. Pursuant to Ind. Code § 8-1-2-42(d), CEI South files a quarterly Fuel Adjustment Clause ("FAC") proceeding in Cause No. 38708 FAC XXX to adjust its rates to account for fluctuation in its fuel and purchased energy costs.

c. DSMA. CEI South recovers demand side management costs, including costs associated with the direct load control inspection and maintenance program, performance incentives, and lost margins, through its Demand Side Management Adjustment ("DSMA") filed annually in Cause No. 43405 DSMA XX.

d. CECA. CEI South recovers, through its Clean Energy Cost Adjustment ("CECA") filed annually in Cause No. 44909 CECA XX, eligible costs of approved clean energy projects under Ind. Code ch. 8-1-8.8, including (a) engineering and project management, management and administration, permitting, contractor site preparation, equipment, and installation costs during construction; and (b) depreciation expense, post-in-service carrying costs ("PISCC"), taxes, and operation and maintenance ("O&M") expense once the projects are placed in service. CEI South's current CECA mechanism includes a component to pass back credits resulting from the Inflation Reduction Act ("IRA"). In this Cause, CEI South proposed to remove this component from the CECA mechanism and include it in a separate Tax Adjustment Rider ("TAR"). In addition, CEI South uses the CECA mechanism to pass on to customers net revenues from the sale of renewable energy credits ("RECs") related to CEI South's various renewable energy projects.

e. ECA. CEI South files annual Environmental Cost Adjustment ("ECA") proceedings in Cause No. 45052 ECA XX to effectuate timely recovery of 80% of its federally mandated costs (as defined by Ind. Code § 8-1-8.4-2) attributable to the following five compliance projects: (1) federally mandated requirements related to CEI South's Culley Unit 3 generating station (Culley 3 Project); (2) clean coal technology projects at CEI South's Culley Unit 3 and Warrick Unit 4 (collectively the MATS Projects); (3) federally mandated requirements to close CEI South's A.B. Brown ash pond (Brown Pond Project); (4) federally mandated compliance projects including a dry fly ash loading facility (Dry Ash Compliance Project) and federally mandated lined ponds at the A.B. Brown and F.B. Culley generating stations to handle coal-pile runoff, flue gas desulfurization wastewater, and other flows such as stormwater and landfill leachate in compliance with the EPA's coal combustion residuals ("CCR") rules (Pond Compliance Project) (collectively, CCR Compliance Projects); and (5) federally mandated requirements required to close by removal ("CBR") CEI South's F.B. Culley east ash pond (the "CBR Project").[2]

f. MCRA. CEI South files annual Midcontinent Independent System Operator ("MISO") Cost and Revenue Adjustment ("MCRA") proceedings in Cause No. 43354 MCRA XX to recover costs associated with non-fuel-related MISO Day 1, Day 2, and Ancillary Services Market costs. CEI South proposed updates for the MCRA in this Cause as described in the direct testimony of Matthew A. Rice.

[2] CEI South's request for a Certificate of Public Convenience and Necessity for the CBR Project was pending when this Cause was filed but has since been approved by the Commission's February 7, 2024 Order in Cause No. 45903.

g. RCRA. CEI South files annual Reliability Cost and Revenue Adjustment ("RCRA") proceedings in Cause No. 43406 RCRA XX to track the differences between certain actual costs and revenues and the amounts of those costs and revenues included in CEI South's base rates. RCRA cost and revenue components include the non-fuel component of purchased power, cost of Environmental Emission Allowances ("EEAs"), Interruptible Sales billing credits, the retail sharing portion of Wholesale Power marketing margins, the margin from Municipal Wholesale Sales, and the retail portion of the margin from EEA sales (net of cost). CEI South has proposed updates for the RCRA in this Cause as described in the direct testimony of Matthew A. Rice.

h. TDSIC. Pursuant to the Commission's September 20, 2017 Order in Cause No. 44910, CEI South files a semi-annual proceeding in Cause No. 44910 TDSIC XX to recover 80% of approved capital expenditures and transmission, distribution, and storage system improvements ("TDSIC") costs incurred in connection with CEI South's TDSIC Projects through its TDSIC Rider. CEI South's current TDSIC mechanism includes a component to pass back credits resulting from changes in the federal tax rates under the TCJA. CEI South has proposed in this Cause to remove this component from the TDSIC mechanism and include it in the TAR. The TDSIC Plan approved in Cause No. 44910 expired December 31, 2023, and CEI South's new TDSIC Plan was approved in Cause No. 45894 on December 27, 2023.

i. Securitization. As a result of the Commission's financing order dated January 4, 2023, in Cause No. 45722, CEI South was authorized to implement, collect, and receive Securitization Charges associated with the securitization of A.B. Brown Units 1 and 2 pursuant to its Securitization of Coal Plants Tariff. Pursuant to that financing order, the accumulated deferred income taxes ("ADIT") associated with the retiring A.B. Brown Units 1 and 2 are segregated from all other ADIT and not included in the calculation of Petitioner's capital structure or otherwise used in finding CEI South's authorized return in future rate cases. The financing order also established a Securitization ADIT Credit tariff to provide an annual credit to customers for the ADIT associated with A.B. Brown Units 1 and 2. In addition, the financing order required that the excess ADIT associated with A.B. Brown Units 1 and 2 be amortized and returned to customers over the life of the related Securitization Bonds. The excess accumulated deferred income taxes ("EADIT") resulting from the TCJA is being flowed back to customers via the TDSIC. As described below, the Company is proposing to continue to flow back this EADIT over the life of the bonds but through the new TAR instead of the TDSIC. The Securitization Rate Reduction ("SRR") tariff was a temporary rider established in Cause No. 45722 to provide customers with a credit for A.B. Brown Net Plant. CEI South proposes to zero out the SRR tariff in customer rates in this case (subject to variances), as the A.B. Brown Units 1 and 2 will no longer be included in base rates.

j. <u>Depreciation and Accrual Rates</u>. Petitioner's current electric depreciation rates were approved by the Commission's Order in Cause No. 43111 on August 15, 2007, and subsequently re-authorized (with a modification to the depreciation rate applicable to the Blackfoot landfill gas generating station) in Cause No. 43839 (April 27, 2011). Petitioner's current common plant depreciation rates were approved by the Commission's Order in Cause No. 45447 on October 6, 2021. Depreciation rates for Petitioner's CTs and Posey Solar were approved by the Commission's Orders in Cause No. 45564 on June 28, 2022, and Cause No. 45847 on September 6, 2023, respectively.

2. Status of Pending Electric Base Rate Case. On December 5, 2023, CEI South filed with the Commission its Verified Petition for General Rate Increase and Associated Relief under Ind. Code § 8-1-2-42.7 and Alternative Regulatory Plan under Ind. Code ch. 8-1-2.5 and Notice of Provision of Information in Accordance with the Minimum Standard Filing Requirements ("Petition") in this Cause. CEI South also filed its prepared testimony and exhibits constituting its case-in-chief on that date. CEI South proposed a three-phase rate implementation, with potential interim phases as described in the direct testimony of CEI South Witness Behme. By Docket Entry issued December 28, 2023, as amended on January 17, 2024, the Commission established the procedural schedule in this case as well as the forward-looking test year for determining Petitioner's projected operating revenues, expenses, and operating income as the 12-month period ending December 31, 2025. The January 17, 2024 Docket Entry also established the rate base cutoff date at the end of the test year and associated rate base cutoff dates for each step of CEI South's proposed three-phase increase.

On March 12, 2024, the Indiana Office of Utility Consumer Counselor ("OUCC") and intervenors filed their respective cases-in-chief. CEI South filed its rebuttal testimony and evidence, and the Industrial Group and Citizens Action Coalition of Indiana, Inc. ("CAC") filed cross-answering testimony on April 9, 2024.

3. Summary of CEI South Requested Relief. CEI South's total proposed rate increase as set forth in its case-in-chief was $118,757,693, and after rebuttal was $115,445,697, which is approximately 15.95% from pro forma revenues at the rates that would be in effect had this case not been filed. CEI South is also seeking approval of new electric and common plant depreciation rates in this Cause, based on the study

sponsored by John R. Spanos except that the rates for Petitioner's CTs and Posey Solar shall remain unchanged from what was approved in Cause Nos. 45564 and 45847, respectively. CEI South also proposed a new Tax Adjustment Rider to include (i) the passback of EADIT to customers which is currently being passed back through CEI South's TDSIC pursuant to the settlement approved in Cause No. 45032 S21, (ii) the effects of Production Tax Credits ("PTCs") resulting from the IRA that are not reflected in base rates, which is currently authorized to be reflected in CEI South's CECA filings, and (iii) the new corporate alternative minimum tax ("CAMT") established under the IRA. CEI South also proposed a new Green Energy Rider to allow eligible customers to purchase up to 85% of the RECs that are received for generation produced by CEI South's renewable generating resources, a new Rider ADR to allow customers to partner with an aggregator to successfully lower load during MISO events, and a critical peak pricing ("CPP") pilot program to explore the potential use of time of use ("TOU") rates to help manage peak loads during hours of highest usage. CEI South sought authorization to establish a regulatory asset to reflect amounts not already included in base rates that are incurred for third-party cloud computing arrangements ("CCAs"). Finally, CEI South included a request for approval of an Alternative Regulatory Plan ("ARP") to grant CEI South a waiver from the requirements of 170 IAC 4-1-16(f) and allow for remote disconnection and reconnections.

B. Settlement Terms and Conditions.

1. <u>Phased Base Rate Increases</u>.

a. <u>Settlement Phase 1</u>. The Settling Parties agree that CEI South's proposed Phase 1 implementation shall be eliminated and CEI South should be authorized to increase its base rates and charges for electric utility service in two steps at a defined point in time as described in this Settlement Agreement. The first change in rates will be implemented pursuant to the process described below and will be based on the agreed revenue requirement as adjusted to reflect the actual capital structure and rate base as of December 31, 2024 subject to the Net Original Cost Rate Base Cap described in Paragraph B.3.a below ("Settlement Phase 1"). Following issuance of a Final Order in this Cause approving this Settlement, Settlement Phase 1 rates will go into effect after the beginning of the test year and upon the effective date of the Commission's approval of the Settlement Phase 1 compliance filing (currently anticipated to be on or around March 1, 2025) for services-rendered after that effective date. Settlement Phase 1 rates will be implemented on an interim-subject-to-refund basis pending a 60-day period for the parties to submit objections to the compliance filing. CEI South shall submit a certification of its actual utility plant in service and actual capital structure as part of its compliance filing. The compliance filing will calculate rates for the applicable phase based upon these certifications, subject to the Net Original Cost Rate Base Cap. If necessary to resolve any objections, the Commission shall schedule a hearing. However, within a week of CEI South's compliance filing, a technical conference may be held at the request of either a party or Commission staff to allow for further discussion in determining whether CEI South's filing complies with the Order in this Cause and to determine what additional information, if any, should be provided for the Settlement Phase 2 compliance filing. .

b. Settlement Phase 2. The second defined change in rates will be implemented pursuant to the process described above and will be based on the agreed revenue requirement as adjusted to reflect the actual capital structure and rate base as of the end of the test year (December 31, 2025), subject to the Net Original Cost Rate Base Cap described in Paragraph B.3.a below ("Settlement Phase 2"). Settlement Phase 2 rates will go into effect upon the effective date of the Commission's approval of the Settlement Phase 2 compliance filing (currently anticipated to be on or around March 1, 2026) for services-rendered after that effective date. Settlement Phase 2 rates will be implemented on an interim-subject-to-refund basis pending a 60-day review using the process described above.

c. Interim Phases. The Settling Parties agree CEI South should be authorized to implement interim rate increase steps after the Posey Solar and the CT Projects are placed in service as described by CEI South Witness Behme. Based upon projected in-service dates of May 2025 for Posey Solar Project and July 2025 for the CT Project, this results in a projected reduction to proposed rate base as reflected in Paragraph B.3.a.iii. The actual reduction to rate base and the Net Original Cost Rate Base Cap will be based upon the actual reduction to forecasted PISCC and deferred depreciation based upon the actual in-service dates and actual rate implementation through interim steps.

2. Revenue Requirement and Net Operating Income.

a. Revenue Requirement. The Settling Parties agree that CEI South's base rates will be designed to produce total pro forma operating revenues of $803,932,466. This represents an overall net revenue increase (net of the reduction to revenues from the stipulated fuel and purchased power expense reduction set forth in Paragraphs B.5.a and B.5.c, when compared to revenues from rates that would be in effect without filing this case, of $80,009,617, which is a decrease of $38,748,076 from the amount requested by CEI South in its case-in-chief and a decrease of $35,436,080 from the amount requested on rebuttal. Appendix A, attached hereto and incorporated by reference, includes schedules supporting the calculation of CEI South's revenue requirement as of December 31, 2024 and December 31, 2025. Petitioner's Exhibit 20-S, filed with the Commission contemporaneously herewith, contains the updated Revenue Requirement Model reflecting the terms of this Stipulation and Settlement Agreement.

b. Net Operating Income. The Settling Parties agree that CEI South's Revenue Requirement as stipulated in Paragraph B.2.a results in an authorized net operating income ("NOI") of $187,518,958.

3. Original Cost Rate Base, Capital Structure and Fair Return.

a. Original Cost Rate Base. The Settling Parties agree that CEI South's original cost rate base on which it should be permitted to earn a return shall be the actual net original cost rate base as of December 31, 2024 (for Settlement Phase 1 as defined in Paragraph B.1.a above) and December 31, 2025 (for Settlement Phase 2 as defined in Paragraph B.1.b above); *provided, however*, that net original cost rate base at either Settlement Phase 1 or Settlement Phase 2 shall not exceed the forecasted end-of-test-year net original cost rate base of $2,769,851,666, as adjusted for the actual reduction to forecasted post-in-service carrying charges and deferred depreciation based upon the actual in-service dates and actual rate implementation through interim steps for the CT Project and Posey Solar (the "Net Original Cost Rate Base Cap"), which reflects the following stipulated modifications to CEI South's forecasted rate base at rebuttal:

i. Reduction to coal inventory of an additional $2,949,966 as proposed by OUCC Witness Eckert.

ii. Removal of $212,036 in additional net investment in the Urban Living Research Center, as recommended by OUCC Witness Armstrong.

iii. Reduction for avoided PISCC and deferred depreciation in conjunction with the stipulations set forth in Paragraph B.1.c above regarding interim phases of rates.

b. Other Rate Base Items.

i. CEI South stipulates and confirms that the amounts reflected in the table below related to land acquisition and identified in the pre-filed testimony of OUCC Witness Armstrong are not included in the forecasted rate base in this Cause and will not be reflected in the actual rate base for purposes of Settlement Phase 1 or Settlement Phase 2 rates:

Table B.3.b.i

Work Order Number	SAP Order	Work Order Description	Total	FERC Account
17410001022013		Future Use Land 8520 Welborn	$ 269,295.15	340.1 Land
17434301022011		Land for Future Use	$ 1,098,217.72	340.1 Land
18410001022011		2018 Smith Diamond Rd - Land	$ 161,154.79	340.1 Land
19410001022012	**13101475**	ABB Land Purchase 2019	$ 273,551.34	310.1 Land
20410001022011	**13102434**	2020 Land Purchase - AB Brown	$ 341,647.36	310.1 Land
Grand Total			**$ 2,143,866.36**	

ii. CEI South stipulates and confirms that the amounts related to the Culley Unit 3 Natural Gas conversion and identified in the confidential pre-filed testimony of OUCC Witness

Krieger and confidential rebuttal testimony of F. Shane Bradford will not be included in rate base in this Cause, but will instead be addressed as part of Petitioner's later anticipated proposed certificate of public convenience and necessity ("CPCN") proceeding related to said conversion.

c. Capital Structure. The Settling Parties agree that CEI South's authorized Return on Equity should be 9.80%. Based on the following capital structure as of the end of the test year, the 9.80% ROE and the cost of debt and zero cost capital as agreed, the overall weighted average cost of capital is computed as follows:

Table B.3.c

Class of Capital	Reference	Amount ($000)		Percent	Cost	Weighted Cost
Long-Term Debt	SCH D-2	$	1,294,210	39.49%	5.12%	2.02%
Preferred Stock	SCH D-3	$	-	0.00%	0.00%	0.00%
Common Equity	SCH D-4	$	1,582,041	48.28%	9.80%	4.73%
Cost Free Capital	SCH D-5	$	390,113	11.90%	0.00%	0.00%
Other Capital	SCH D-5	$	10,754	0.33%	5.87%	0.02%
Total Capital	Sum of Lines 1 - 5	$	3,277,119	100.00%		6.77%

d. Fair Return. The Settling Parties stipulate and agree that the agreed weighted cost of capital times the stipulated net original cost rate base yields a fair return on the fair value of rate base for purposes of this case. Accordingly, the Settling Parties agree that CEI South should be authorized a fair return of $187,518,958 yielding an overall return for earnings test purposes of 6.77% based upon the stipulated net original cost rate base, capital structure and ROE as set forth above in this Section B.3.

4. Depreciation and Amortization Expense.

a. Depreciation Expense. The Settling Parties stipulate that the depreciation accrual rates recommended by OUCC Witness David J. Garrett as presented in Public's Exhibit No. 11, Attachment DJG-5, should be approved and used in the determination of net plant in service values for calculation of Settlement Phase 1 and Settlement Phase 2 rates, *except* the depreciation rates for the CT Project and Posey Solar shall remain unchanged from those approved in their respective CPCN proceedings.

b. Amortization Expense.

i. The Settling Parties agree to the amortization of Indiana state excess accumulated deferred income taxes ("Indiana state EADIT") over three years as proposed by OUCC Witness Stull and Industrial Group Witness Gorman, except that Witness Stull's recommendation to impose carrying charges should be rejected. CEI South's proposal is to reflect all refunds of EADIT through the TAR; therefore, this stipulated term does not affect the revenue requirement.

ii. If not already addressed by an intervening base rate case order before expiration of various amortization periods, CEI South agrees to file a revised tariff to remove the annual amortization amount from base rates upon each such expiration, unless a new general rate case petition is pending at that time.

5. Pro Forma Revenues and Expenses.

a. Base Cost of Fuel. The Settling Parties agree that the forecasted base cost of fuel included in the test year revenue requirement shall be reduced by $8,175,808 as recommended by OUCC Witness Eckert.

b. Interruptible Sales Billing Credits. The Settling Parties agree that CEI South's proposal to include $725,000 in interruptible sales billing credits shall be rejected, as recommended by OUCC Witness Lantrip. Any actual interruptible sales billing credits shall be reflected in the RCRA.

c. Capacity Purchase Costs. The Settling Parties agree that the forecasted capacity purchase costs included in the test year revenue requirement shall be reduced by $5,000,000.

d. Operations & Maintenance Expense. The Settling Parties stipulate to a reduction to CEI South's total forecasted level of Operations & Maintenance ("O&M") expense presented in its case-in-chief of $1,350,000. The Settling Parties further agree to include $813,540 related to cloud computing arrangements ("CCAs") in forecasted test year O&M expense for purposes of the revenue requirement.

6. Accounting Treatment for Cloud Computing Costs. Subject to the stipulation and agreement set forth in Paragraph B.5.d above with respect to CCAs, CEI South agrees to withdraw its request for creation of a regulatory asset for post-test year cloud computing costs; *provided*, *however*, that such withdrawal is without prejudice, and CEI South reserves its rights with respect, to filing for such relief in a separate docketed proceeding.

7. Proposed Riders.

a. Critical Peak Pricing Pilot, Rider ADR, and Green Energy Rider. The Settling Parties stipulate and agree that CEI South's Critical Peak Pricing Pilot, Rider ADR, and Green Energy Rider should be approved as proposed by CEI South. CEI South commits to providing all parties to this Cause a copy of the contract with the demand response aggregator after it has been signed.

b. Tax Adjustment Rider. The Settling Parties stipulate and agree that while the actual effects of the CAMT occurring by the beginning and end of the test year will be reflected in CEI South's capital structure for purposes of Settlement Phase 1 and Settlement Phase 2 rates, respectively, CEI South shall withdraw its request to include future Corporate Alternative Minimum Tax ("CAMT") effects in its Tax Adjustment Rider ("TAR").

8. Other Tariff Matters.

a. IC and IO Riders. CEI South agrees to continue conversations with interested stakeholders regarding changes to its Interruptible Contract ("IC") and Interruptible Option ("IO") riders related to Demand Response.

b. Limitation of Liability. CEI South agrees to adopt and incorporate the changes to its limitation of liability provision in its tariff as recommended by IG Witness Gorman and modified by CEI South Witness Rice on rebuttal.

9. Alternative Regulatory Plan for Remote Disconnection ("ARP"). CEI South agrees to incorporate the protections contained in the rebuttal testimony of CEI South witness Folz and Paragraph B.10 below. The Settling Parties stipulate the approval of the ARP, as modified pursuant to this Paragraph B.9, will be left to the Commission's discretion and determination.

10. Customer Protection Provisions.

a. LIHEAP Customer Deposits. If an applicant for residential service or current residential customer is qualified by the applicable LIHEAP-affiliate community action agency to participate in the Low Income Home Energy Assistance Program ("LIHEAP Qualified Participant"), the residential deposit amount will be limited to $50.00. LIHEAP qualification can be from the current heating season or one-year prior heating season.

b. Residential Late Payment Charge. CEI South agrees that, following EIP implementation, once per calendar year, upon request by a residential customer, CEI South will waive the late payment charge on a delinquent bill, provided payment is tendered not later than the last date for payment of the net amount of the next succeeding month's bill.

c. LIHEAP Qualified Participants- Fees; Reporting.

i. CEI South agrees that, following EIP implementation, once per calendar year, the Company will waive the manual disconnection and manual or, subject to approval of the ARP by the Commission, remote reconnection fees of a LIHEAP Qualified Participant.

ii. CEI South agrees to report data on LIHEAP Qualified Participants consistent with the type of data that CEI South reported in Cause No. 45830 and currently reports pursuant to the agreement with the OUCC as a result of Cause No. 45736. CEI South will include this data in its annual Collaboration Report resulting from Cause No. 45564. Specifically, CEI South agrees to provide:

1. Number of residential accounts receiving assistance under the LIHEAP program. For purposes of this reporting, LIHEAP is defined as assistance provided by Community Action Program ("CAP") agencies and/or CenterPoint Energy Indiana's Universal Service Program (USP).
2. Number of LIHEAP accounts that are past due where "past due" is defined as accounts that are any number of days past due.
3. Total dollars owed with respect to LIHEAP accounts that are in arrears.

d. <u>Disconnections/Reconnections</u>.

i. <u>Remote Disconnection/Reconnection</u>. CEI South agrees that if its ARP for remote disconnections/reconnections is approved by the Commission:

1. CEI South will provide at least thirty (30) days advance notice to customers before implementing the remote disconnection/reconnection proposal.
2. The fee for remote disconnection shall remain $0, consistent with CEI South's case-in-chief; and the fee for remote reconnection shall be reduced from $5 to $3.
3. For LIHEAP Qualified Participants, CEI South will waive, once per calendar year per customer, the after-hours remote reconnection charge set forth in CEI South's tariff as $54.19.

4. If a residential customer is designated as "Medical Need" or "Life Support", does not have an AMI meter, or has not provided a phone number or email address, CEI South will make an on-premises visit on the day of disconnect. As specified in CEI South's case-in-chief, Medical Need and Life Support Customers will be excluded from remote disconnection.

ii. Disconnection Service Hours for Non-Payment. CEI South agrees not to disconnect service for non-payment for any residential customer on Fridays, Saturdays, Sundays, and the following Holidays: New Year's Day, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Friday after Thanksgiving Day, December 24, and Christmas Day.

iii. Medical Need or Life Support Customers. CEI South agrees to increase the current protection from disconnection for Medical Need (10 days) or Life Support (20 days) to 30 days for both categories. Before any disconnection of a LIHEAP Qualified Participant designated as Medical Need or Life Support, CEI South will place a collection call to such customer that prompts the customer to contact CEI South to establish an installment plan.

11. Multi-Family Data Collection & Analysis. CEI South agrees to collect data on residential customer housing types and analyze cost differentials between single- and multi-family residential customers. In advance of its next rate case, CEI South will offer to

meet to discuss methodology and share initial results of its analysis with any interested party to this Cause.

12. Customer Bill Transparency. CEI South agrees to provide more transparency on its customer bills for CEI South customers as soon as practicable after issuance of a final order and after implementation of EIP, to include additional line items that break out the following:

- Service Charge
- Variable charges (charges tied to usage)
- FAC
- Sales Tax
- Total

CEI South will provide a copy of these changes to all parties to this Cause prior to implementation.

13. Cost of Service - Cost Allocation and Revenue Distribution.

The Settling Parties agree to use CEI South's cost of service study as modified herein and revenue allocation also as described herein. The agreed upon cost of service study and the revenue allocation for purposes of designing rates are depicted in the schedules attached hereto as Appendix B and incorporated by reference. Pursuant to Ind. Code § 8-1-39-9, future TDSIC allocators are based on the proposed revenue allocation by rate class (*i.e.*, the mitigated allocation of the allocated cost of service study revenue) and presented in Appendix B.

a. Generation and Transmission costs will be allocated using the 4CP methodology as in the last general rate case and the allocators from CEI South's testimony in this Cause No. 45990. These allocators will continue to be used in various tracker filings, subject to Commission determinations in particular proceedings.

b. Customer costs will be determined based upon the minimum system study prepared by CEI South Witness Taylor, also consistent with the methodology used in the last general rate case.

c. The Settling Parties stipulate and agree that:

i. No class will receive a rate decrease as a result of the rates implemented pursuant to this Stipulation and Settlement Agreement.

ii. No class will receive a rate increase that is higher than what CEI South proposed in its rebuttal position in this Cause.

iii. Other than water heating, no class will receive a rate increase greater than 1.35x the system average. Water heating will receive a rate increase of 1.5x the system average, as proposed in CEI South's direct and rebuttal positions.

14. Rate Design. The Settling Parties stipulate and agree to set the customer charges (i.e., the fixed portion of the bill) for each class at the level prior to the repeal of the Utility Receipts Tax. For clarification, the customer charge stipulated to in this agreement does not include the fixed portion of TDSIC recovery. The stipulated customer charges are as set forth below:

Rate Schedule	Customer Charge
RS	$11.00
B	$5.00
SGS	$11.00

DGS-1	$15.00
DGS-2	$35.00
DGS-3	$75.00
OSS	$15.00
LP	$150.00

15. Other Disputed Items.

a. BAMP Rates. CEI South agrees to evaluate the reasonableness of moving the Backup Service Transmission Rate towards parity with FERC Attachment O price and hold discussions with SABIC in advance of CEI South's next base rate case to determine the appropriate, cost-of-service-based Backup Service Transmission Rate.

b. All Other Items. The Settling Parties stipulate and agree that all other disputed items not expressly delineated herein shall be resolved as proposed in CEI South's case-in-chief, as modified by its rebuttal position where applicable, to the extent expressly supported in CEI South's evidence and without waiving the right of any party to litigate such issues in future proceedings.

C. Effect of Settlement and Procedural Matters.

1. Scope and Effect of Settlement.

a. Neither the making of this Settlement Agreement nor any of its provisions shall constitute in any respect an admission by any Settling Party in this or any other litigation or proceeding. Neither the making 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.

b. This Settlement Agreement shall not constitute nor be cited as precedent by any person or deemed an admission by any Settling Party in any other proceeding except as necessary to enforce its terms before the Commission, or any tribunal of competent jurisdiction. 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 of the Settling Parties may take with respect to any or all of the issues resolved herein in any future regulatory or other proceedings.

c. The Settling Parties' entry into this Settlement Agreement shall not be construed as a limitation on any position they may take or relief they may seek in other pending or future Commission proceedings not specifically addressed in this Settlement Agreement.

2. Authority to Enter Settlement. The undersigned have represented and agreed that they are fully authorized to execute this Settlement Agreement on behalf of their designated clients, and their successors and assigns, who will be bound thereby, subject to the agreement of the Settling Parties on the provisions contained herein.

3. Privileged Settlement Communications. The communications and discussions during the negotiations and conferences have been conducted based on the explicit understanding that said communications and discussions are or relate to offers of settlement and therefore are privileged. All prior drafts of this Settlement Agreement and any settlement proposals and counterproposals also are or relate to offers of settlement and are privileged.

4. Conditions of Settlement. This Settlement Agreement is conditioned upon and subject to Commission acceptance and approval of its terms in their entirety, without any change or condition that is unacceptable to any Settling Party.

5. Evidence in Support of Settlement. CEI South, the Industrial Group and SABIC shall offer their respective direct and rebuttal testimonies and supplemental testimony supporting the Commission's approval of this Settlement Agreement and will request that the Commission issue a Final Order incorporating the agreed proposed language of the Settling Parties and accepting and approving the same in accordance with its terms without any modification. Such supportive testimony will be offered into evidence without objection by any Settling Party. The Settling Parties hereby waive cross-examination of each other's witnesses.

6. Commission Approval. The Settling Parties will support this Settlement Agreement before the Commission and request that the Commission accept and approve the Settlement Agreement. This Settlement Agreement is a complete, interrelated package and is not severable, and shall be accepted or rejected in its entirety without modification or further condition(s) that may be unacceptable to any Settling Party. If the Commission does not approve the Settlement Agreement in its entirety, the Settlement Agreement shall be null and void and deemed withdrawn, upon notice in writing by any Settling Party within fifteen (15) business days after the date of the Final Order that any modifications made by the Commission are unacceptable to it. In the event the Settlement Agreement is withdrawn, the Settling Parties will request that an Attorneys' Conference be convened to establish a procedural schedule for the continued litigation of this proceeding.

7. Proposed Order. The Settling Parties will work together to prepare an agreed upon proposed order to be submitted in this Cause. The Settling Parties will request Commission acceptance and approval of this Settlement Agreement in its

entirety, without any change or condition that is unacceptable to any party to this Settlement Agreement.

8. Publicity. The Settling Parties also will work cooperatively on news releases or other announcements to the public about this Settlement Agreement.

9. Waiver of Opposition. The Settling Parties shall not appeal or seek rehearing, reconsideration or a stay of any Final Order entered by the Commission approving the Settlement Agreement in its entirety without changes or condition(s) unacceptable to any Settling Party (or related orders to the extent such orders are specifically and exclusively implementing the provisions hereof) and shall not oppose this Settlement Agreement in the event of any appeal or a request for rehearing, reconsideration or a stay by any person not a party hereto.

Accepted and Agreed on this 20th day of May, 2024.

(signature page follows)

Southern Indiana Gas and Electric Company
d/b/a CenterPoint Energy Indiana South

By:________________________________
Printed Name: Richard C. Leger

CEI South Industrial Group

By:________________________________
Printed Name:

SABIC Innovative Plastics Mt. Vernon LLC

By:________________________________
Printed Name:

Southern Indiana Gas and Electric Company
d/b/a CenterPoint Energy Indiana South

By:________________________________
Printed Name:

CEI South Industrial Group

By:________________________________
Printed Name: Todd A. Richardson

SABIC Innovative Plastics Mt. Vernon LLC

By:________________________________
Printed Name:

Southern Indiana Gas and Electric Company
d/b/a CenterPoint Energy Indiana South

By:______________________________
Printed Name:

CEI South Industrial Group

By:______________________________
Printed Name:

SABIC Innovative Plastics Mt. Vernon LLC

By: Nikki Shoultz
Printed Name: Nikki Shoultz

CEI SOUTH
CAUSE NO. 45990
PET'S EX. NO. 20-S
CURRENT AND ADJUSTED PRO FORMA INCOME STATEMENT
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2025

SCHEDULE C-1.1a
WITNESS RESPONSIBLE:
C. M. BEHME / S. E. GRAY

Line	Description	Test Year Unadjusted (A)	Pro Forma Adjustments (B)	Pro Forma at Present Rates (C)	Increase (D)		Pro Forma at Proposed Rates (E)
1	OPERATING REVENUES						
2	Base Revenue and Riders	$ 721,683,471	$ 2,239,378	$ 723,922,849	$ 80,009,617		$ 803,932,466
3	Total Operating Revenues	$ 721,683,471	2,239,378	$ 723,922,849	$ 80,009,617	(A)	$ 803,932,466
4							
5	FUEL AND PURCHASED POWER						
6	Fuel	$ 274,718,361	$ (14,525,860)	$ 260,192,501	$ (13,963,191)		$ 246,229,310
7	Total Fuel and Purchased Power Expense	$ 274,718,361	(14,525,860)	$ 260,192,501	$ (13,963,191)		$ 246,229,310
8							
9	MARGIN	$ 446,965,110	$ 16,765,238	$ 463,730,348	$ 93,972,808		$ 557,703,156
10							
11	OPERATING EXPENSES						
12	Steam Power Generation Expense	$ 44,521,454	(14,049,267)	$ 30,472,187	$ -		$ 30,472,187
13	Other Power Generation Expense	15,150,128	13,825	15,163,953	-		15,163,953
14	Other Power Supply Expense	670,659	-	670,659	-		670,659
15	Transmission Expense	23,817,994	195,902	24,013,896	-		24,013,896
16	Distribution Expense	23,077,201	(143,586)	22,933,615	-		22,933,615
17	Customer Accounts Expense	3,678,296	(20,197)	3,658,099	-		3,658,099
18	Customer Service & Information Expense	14,853,347	(13,673,275)	1,180,073	-		1,180,073
19	Sales Expense	-	-	-	-		-
20	Administrative & General Expense	52,414,815	(3,028,251)	49,386,564	419,833		49,806,398
21	Total Operation & Maintenance Expense	$ 178,183,894	$ (30,704,849)	$ 147,479,045	$ 419,833		$ 147,898,878
22							
23	Total Operating Expense	$ 178,183,894	$ (30,704,849)	$ 147,479,045	$ 419,833		$ 147,898,878
24							
25	Depreciation Expense	$ 116,624,348	$ 21,004,605	$ 137,628,953	$ -		$ 137,628,953
26	Amortization Expense	4,145,539	30,029,706	34,175,245	-		34,175,245
27	Total Depreciation and Amortization Expense	$ 120,769,887	$ 51,034,311	$ 171,804,198	$ -		$ 171,804,198
28							
29	Taxes Other Than Income Taxes						
30	Property Taxes	$ 15,550,000	$ (6,033,137)	$ 9,516,863	$ -		$ 9,516,863
31	Other Taxes	2,838,115	(54,904)	2,783,210	-		2,783,210
32	Total Taxes Other Than Income Taxes	$ 18,388,115	(6,088,042)	$ 12,300,073	$ -		$ 12,300,073
33							
34	Income Taxes						
35	State Income Taxes	$ 1,011,151	$ (1,011,151)	$ (0)	$ 4,584,096		$ 4,584,096
36	Deferred Income Taxes - State	3,522,567	396,825	$ 3,919,391			3,919,391
37	Federal Income Taxes	4,063,651	7,260,802	$ 11,324,453	18,683,465		30,007,918
38	Deferred Income Taxes - Federal	10,978,418	(11,308,773)	$ (330,355)	-		(330,355)
39	Total Income Tax Expense	$ 19,575,787	$ (4,662,298)	$ 14,913,489	$ 23,267,560		$ 38,181,049
40							
41	Investment Tax Credits						
42	Investment Tax Credit Adjustments	$ -	$ -	$ -	$ -		$ -
43	Total Investment Tax Credits	$ -	-	$ -	$ -		$ -
44							
45	Total Operating Expenses and Taxes	$ 336,917,682	$ 9,579,123	$ 346,496,805	$ 23,687,393		$ 370,184,198
46							
47	Net Operating Income	$ 110,047,428	$ 7,186,115	$ 117,233,543	$ 70,285,414		$ 187,518,958

Note

(A) Net increase to gross revenue equals $80,009,617 reflects base revenue increase of $93,972,808 less fuel and purchased power costs of $13,963,191.

INDIANA UTILITY REGULATORY COMMISSION

CAUSE NO. 45990

SOUTHERN INDIANA GAS AND ELECTRIC COMPANY d/b/a CENTERPOINT ENERGY INDIANA SOUTH

Petitioner's Exhibit No. 18-S, Attachment JDT-S2

ALLOCATED COST OF SERVICE STUDY
TEST YEAR
ENDED DECEMBER 31, 2025

Witness: John D. Taylor

ATRIUM ECONOMICS
CENTERED ON ENERGY

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I. INTRODUCTION

The purpose of this document is to discuss the development and results of the Cost of Service Study ("COSS") model and related schedules prepared for Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South ("CEI South," "CEIS," or "the Company") based on the Test Year ended December 31, 2025 ("TY").

The document is organized into three sections. The first section discusses the purpose of cost allocation and includes an overview of Atrium's COSS model used to develop the cost allocation study. The second section, CEI South's Cost of Service Procedures, includes details of the methodologies adopted in the development of the study. The last section exhibits the results of the cost of service allocation.

1. Purpose of Cost Allocation

The purpose of the COSS is to determine the cost of service responsibilities of each customer class upon which the base rates may be established. The revenue requirement studies provide the overall level of costs of providing service, while the COSS is used to change the basic rate structures and/or the relative overall cost responsibility of each customer class. Based on the functionalization and classification of costs and allocation methodologies used in the COSS, the revenue requirement by customer class is determined and used in designing the Company's proposed base rates. In other words, the COSS measures each class's contribution to the Company's overall cost of service. Comparing the costs to serve any customer class with that class's rate revenues provides a measure of the return realized from that class and their associated revenue-to-cost ratio. This allows for a comparison across classes to ascertain the presence and extent of interclass subsidization (i.e., when one class pays more than its cost to serve and another pays less than its cost to serve).

2. COSS Procedures

Cost of service studies utilize a three-step process: functionalization, classification, and allocation.

In the first step, the functionalization sets off with assigning Federal Energy Regulatory Commission ("FERC") plant accounts and associated investment balances to appropriate cost of service functions. The expenses related to particular property investments or groups of investments can often follow the same functionalization and are allocated based on the ratios of the electric plant assigned to each function. These plant ratios can be used to functionalize most other cost items.

In the second step, classification, each functional cost category is further separated by cost causation. There are three basic cost-defining characteristics of electric services: demand, energy/commodity, and customer.

- Demand (Capacity) related costs are associated with the peak usage of the utility system. These costs are necessary to maintain the system at a level sufficient to satisfy the greatest demand that all the customers could place upon the system.
- Energy/Commodity-related costs are variable costs that vary with the quantity of electricity used. These costs reflect the number of units consumed or supplied during a period of time.

- Customer-related costs are associated with serving customers regardless of their usage or demand characteristics. They are allocated directly to the customers of a particular class of service.

The last step is to allocate these cost components among customer classes. An analysis of the utility's records may indicate specific costs that should be assigned directly to a particular customer class, including plant investments and associated expenses. All the remaining costs that cannot be directly attributable to a specific group of customers are allocated using allocation factors.

3. Atrium Economics Cost of Service Study Model Overview

The Cost of Service Study is submitted in support of the direct testimony of John D. Taylor. The COSS model presented in this proceeding is an excel based model that allows the user to modify various inputs and assumptions.

COSS Model Capabilities

The Atrium Economics' COSS model provides a large range of analytical capabilities including:

- Unbundling of operations into functions: (i.e. production/supply, storage, transmission, distribution, metering, and billing services.)
- Classification and allocation of costs into customer classes.
- Reports on Rate of Return, Revenue Requirement, and Revenue-to-Cost ratio for each function and rate class.
- Development of unit costs of each functional classification for each rate class.
- Specification of the individual rate of return targets for each function or customer class.
- Provides detailed analyses of working capital, income taxes, depreciation reserve, and depreciation expenses.
- Use of detailed analysis of labor expenses by account to facilitate the analyses of administrative and general expenses and overhead costs.
- Facilitation of direct assignment of plant investment, expenses, and revenue dollars to individual functions, classifications, or customer classes.

Follows Traditional 3-Step Allocation

The Atrium COSS Model follows the standard three-step analysis process:1) functionalization of rate base and expenses into various functional categories; 2) classification of functionalized components into demand, energy/commodity, and customer cost categories; and 3) allocation of each component among the customer classes.

As part of the functionalization process, accounts for common costs that are not specifically related to the primary functions, such as general plant and administrative and general expenses, are automatically allocated to the proper function based on internally defined allocation factors. All components of the utility's total cost of service are grouped into one of the functions.

The Atrium COSS Model provides unbundled functionalized and classified cost information by customer class; develops unbundled revenue requirements by functional classification for each customer class; and calculates unit costs by function for customer, energy/commodity, and demand categories. Accounting costs are reported by the FERC account level, and the allocation of A&G expenses, general taxes, and income taxes are clearly reported.

Revenue requirements are calculated from the allocated rate base and expenses and are adjusted to reflect the user-determined target rate of return and statutory tax adjustments. The actual revenues collected are compared to the calculated cost-based revenue requirements to determine class-specific, revenue-to-cost ratios to assist in revenue allocation and pricing activities.

Unit Cost Output Functionality

The COSS model calculates the unit cost of each functional classification separately for each rate class based on the user-specified billing determinants. These unit cost data are among the most important outputs from an embedded cost of service analysis. They are defined as the average cost of providing service to customers per measure of service (i.e., per kilowatt hour, per kilowatt of daily demand, and per customer). Unit costs are a key consideration in developing prices for bundled, unbundled, and re-bundled services.

Acceptance by Utility Regulatory Commissions

The format and presentation of the model's outputs have been used in many rate case proceedings and conform to standard utility commission requirements. Where necessary the COSS model outputs can be easily modified to meet specific jurisdictional filing requirements.

II. CEI SOUTH's COST OF SERVICE PROCEDURES

1. Functionalization

Functionalization is the process of associating each of the numerous detailed elements of the total revenue requirement with functions (and sometimes sub-functions) of the electric utility system. Costs must be first functionalized because each class's service requirement tends to have different relative impacts on each service function. As such, it is necessary to develop separate sub-parts of the total revenue requirement for each function (and sometimes sub-function). The four basic functions and the associated sub-functions are shown in the table below:

Function	Sub-Function
Generation	Production
	Fuel Expenses
	Variable Production Cost
Transmission	Transmission
Distribution	Substation
	Dist Primary
	Dist Secondary
	Transformation
Customer	Onsite & Metering
	Lighting Plant
	Customer Accounts & Service

CEIS's assigned functional categories are presented on Schedule 4.

2. Classification

The second step in the CCOSS process is to classify the functionalized costs as being associated with a measurable customer service requirement which gives rise to the costs

The table below shows how each of the functional and sub-functional costs was classified:

Function	Cost Classification		
	Demand	Energy	Customer
Production	x	x	
Transmission	x		
Substation	x		
Distribution Primary	x		
Distribution Secondary	x		
Transformation	x		x
Onsite & Metering			x
Lighting Plant			x
Customer Accounts & Service			x
Fuel Expenses		x	
VPC		x	

CEI South's assigned classification categories are presented on Schedule 4.

As shown in the table above, transformers are classified as demand and customer related using Minimum System Study. The Minimum System method involves comparing the cost of the minimum size of each type of facility used to the cost of the actual sized facilities installed. The cost of the minimum size facilities determines the "customer" component of total costs, and the "capacity" cost component is the difference between total installed cost and the minimum sized cost.

The table below shows the percent of each cost element that was classified as "customer" related based on the most recent Minimum System study.

Transformers and Transformer	Quantity	Total Replacement Cost	Zero Intercept Unit Cost	Customer Component	Customer Component (%)	Demand Component (%)
Overhead	38,002	$ 108,547,706	$ 1,600	$ 60,815,919	56%	44%
Padmount	18,992	$ 109,728,498	$ 3,238	$ 61,499,914	56%	44%
Total	**56,994**	**$218,276,204**		**$122,315,833**	**56%**	**44%**

3. Allocation

The allocation step involves assigning classified costs to the customer classes based on cost causation. Therefore, the allocation of costs is usually based on some measure of class loads or class service characteristics. The External and Internal Allocation Factors are utilized to allocate costs among various customer classes. CEIS's assigned Allocation Factors are presented on Schedule 4.

3.1. Customer Classes and Tariff Schedules

The following customer classes were identified for purposes of cost allocation:

Rate Schedule	**COSS Customer Class**
Residential (RS)	Residential (RS)
Water Heating (B)	Water Heating (B)
Small General Service (SGS)	Small General Service (SGS)
Demand General Service (DGS)	Demand General Service (DGS)
Off-Season Service (OSS)	Demand General Service (DGS)
Large Power Service (LP)	Large Power Service (LP)
High Load Factor Service (HLF)	High Load Factor Service (HLF)
Outdoor Lighting (OL)	Outdoor Lighting (OL)
Street Lighting (SL)	Street Lighting (SL)

3.2. External Allocation Factors

CEI South's External Allocation Factors are presented on Schedule 5. The External Allocation Factors are developed based on the special studies conducted using various detailed data.

ENERGY/COMMODITY AND REVENUE ALLOCATION FACTORS

Costs classified as Energy are allocated among customer classes based on the kilowatt-hour (kWh) sales for the test year.

REV	The factor directly assigns Current Annualized Revenues Less Fuel Cost Revenues to customer classes.
REV_ENERGY	The factor directly assigns total Fuel Cost Revenue to customer classes.
REV_RIDER	This factor directly assigns all rider revenues (TDSIC, CECA, etc.) less fuel cost revenue to customer classes.
ENERGY	This represents test year kWh consumption for each customer class.
REV_LATE_FEE	The factor directly assigns late fees revenue to customer classes.
REV_FORFEITED	This factor directly assigns forfeited discounts for each customer class.
REV_RECONNECT	The factor directly assigns reconnect charge revenue to each customer class.
REV_NFS	This factor directly assigns returned check charge revenue to each customer class.
REV_MISC	The factor directly assigns miscellaneous revenues collected through the customer classes.
REV_VP	The factor directly assigns variable production revenue through the customer classes.

REV_PROPOSED_VP	The factor directly assigns variable production revenues to customer classes.

CUSTOMER ALLOCATION FACTORS

Customer-related costs are generally allocated based on the number of customers within each class of service, with appropriate weighting to recognize specific service characteristics.

CUST	The factor is based on the average number of customers per customer class.
CUST_BILL	This factor is based on the number of customer bills per customer class.
CUST_PRI	The factor is based on the average number of customers per customer class using the Primary System.
CUST_SEC	The factor is based on the average number of customers per customer class using the Secondary System.
MTRS	The factor is based on the weighted customer unit cost of meters used to serve customers in different rate classes. The analysis relies upon the Company's records, which provide an inventory of each type and size of meter for a specific rate schedule. The average meter current replacement cost (including labor and overhead) was linked to the meter records dataset to develop the total current cost of the investment for each customer class. Then the relative customer class unit cost was developed and multiplied by the customer count for each customer class.
SERV	The analysis relies upon the data contained in the Company's property records which provide an inventory of the average number of service wires by customer class. Additionally, current unit costs per foot by service wire type and design (underground or overhead) were provided by the Company. The method employed to develop the service allocator was similar to that used for the meter allocator.
STREET-LIGHT	The factor is based on the average number of company-owned streetlights.
OUTDOOR-LIGHT	The factor exists to directly assign costs to the Outdoor Lighting class in ACOSS.
MTR_READ	Account 902 Meter Reading Expenses The factor is based on the special study of 902 sub-accounts.
UNCOLL	Account 904 Uncollectible Accounts. The factor is based on three-year average distribution-related write-offs by rate class.

DEMAND ALLOCATION FACTORS

NCP_SEC	Non-Coincident Peak Demand_Secondary (kW) -This factor analyzes each rate class's monthly contribution to the sum of the monthly maximum demands for all classes. The monthly demand is computed by taking a class's maximum non-coincident peak ("NCP") demand across all twelve months. This factor looks only at customers who utilize energy flowing through the secondary distribution system.

NCP_PRI	Non-Coincident Peak Demand_Primary (kW) -This factor analyzes each rate class's monthly contribution to the sum of the monthly maximum demands for all classes. The monthly demand is computed by taking a class's maximum non-coincident peak ("NCP") demand across all twelve months. This factor looks only at customers who utilize energy flowing through the primary distribution system.
12CP_DEMAND	The Twelve Monthly Coincident Peak Factor is based on the twelve months of average system peak responsibility of coincidental class demand.
4CP_DEMAND	The Four Monthly Coincident Peak Factor is based on the average of four peak months of system peak responsibility of coincidental class demand.

3.3. Internal Allocation Factors

Internal Allocation Factors are developed within the COSS model based on the cost ratios of allocated costs. The Internal Allocation Factors are provided in Schedule 5 and described below.

INT_TOTAL_PLANT	Plant Total - The factor is based on the allocated total plant balance by customer class.
INT_RATEBASE	Total Rate Base – The factor is based on the derived rate base by customer class.
INT_DIST_OPS	Distribution related Operation Expense subtotal – The factor is based on the customer class allocated Distribution-related Operation Expenses.
INT_DIST_MAINT	Distribution related Maintenance Expense subtotal – The factor is based on the customer class allocated Distribution-related Maintenance Expenses.
INT_361-364	Distribution Plant Subtotal – The factor is based on the allocated FERC Accounts 361 "Structures and improvements", 362 "Station Equipment", 363 "Storage battery equipment", 364 "Poles, Towers and Fixtures" plant balances by customer class.
INT_364	FERC 364 "Poles, Towers and Fixtures" - The factor is based on the allocated plant balance of FERC Account 364.
INT_365	FERC 365 "Overhead Conductors and Devices" - The factor is based on the allocated plant balance of FERC Account 365.
INT_367	FERC 367 "Underground Conductors and Devices" - The factor is based on the allocated plant balance of FERC Account 367.
INT_368	FERC 368 "Transformers and Transformer Installations" - The factor is based on the allocated plant balance of FERC Account 368.
INT_STNS,POLES,LINES	Distribution Plant Subtotal – The factor is based on the allocated FERC Accounts 362 "Station Equipment", 364 "Poles, Towers and Fixtures", and 365 "Overhead Conductors and Devices" plant balances by customer class.

INT_LABOR	Total Labor Expense – The factor is based on the total customer class allocated labor-related expenses.
INT_REVREQ	Total Revenue Requirement – The factor is based on the derived revenue requirement by customer class.
INT_GENPT	General Plant – The factor is based on the allocated total General Plant balance by customer class.
INT_DIST (60%)_TRANSM (40%)_PLANT	Factor calculated by taking 60% of the allocated total Distribution plant balance and 40% of the allocated total Transmission plant balance by customer class.

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule 1 - Summary of Cost of Service and Rate of Return Under Present and Proposed Rates

Line No.	Category Description	Total System	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
1	**Rate Base**									
2	Plant in Service	$ 3,903,197,879	$ 1,920,914,445	$ 11,376,172	$ 82,940,564	$ 1,099,503,552	$ 729,052,713	$ 25,156,856	$ 8,449,008	$ 25,804,568
3	Accumulated Reserve	(1,227,581,792)	(619,904,244)	(4,619,659)	(30,261,189)	(331,812,514)	(215,381,920)	(7,552,197)	(3,671,412)	(14,378,656)
4	Other Rate Base Items	94,235,578	47,763,533	401,553	2,251,817	24,854,181	17,737,370	759,288	124,888	342,949
5	**Total Rate Base**	**$ 2,769,851,666**	**$ 1,348,773,734**	**$ 7,158,066**	**$ 54,931,192**	**$ 792,545,219**	**$ 531,408,163**	**$ 18,363,947**	**$ 4,902,484**	**$ 11,768,861**
6	**Margin at Current Rates**									
7	Base Rate Revenue	$ 267,328,652	$ 132,139,577	$ 530,561	$ 5,953,227	$ 75,824,903	$ 48,031,238	$ 1,868,205	$ 1,152,148	$ 1,828,794
8	Rider Revenue	99,379,048	49,842,143	487,680	2,724,122	29,673,721	15,662,293	814,423	29,159	145,507
9	Variable Production Revenue	18,054,808	6,551,059	34,459	291,427	5,155,612	5,597,499	331,601	36,004	57,149
10	Special Contract Revenue	47,294,984	21,131,238	127,061	912,170	13,281,362	11,061,526	535,090	76,509	170,028
11	Other Revenue	8,302,436	3,936,989	23,642	167,081	2,258,390	1,784,036	85,831	15,401	31,067
12	Sale for Resale and Transmission Revenue	23,370,420	10,667,078	64,873	459,181	6,550,173	5,261,659	245,488	36,796	85,171
13	**Total Margin at Current Rates**	**$ 463,730,348**	**$ 224,268,083**	**$ 1,268,276**	**$ 10,507,207**	**$ 132,744,161**	**$ 87,398,250**	**$ 3,880,638**	**$ 1,346,017**	**$ 2,317,715**
14	Fuel Cost Revenue	207,300,587	75,970,833	391,108	3,344,186	59,219,378	63,597,486	3,765,866	391,039	620,692
15	Fuel Cost Revenue_Special Contract	52,891,914	19,383,654	99,790	853,256	15,109,587	16,226,644	960,846	99,772	158,367
15	**Total Revenue at Current Rates**	**$ 723,922,849**	**$ 319,622,569**	**$ 1,759,173**	**$ 14,704,649**	**$ 207,073,126**	**$ 167,222,380**	**$ 8,607,350**	**$ 1,836,828**	**$ 3,096,774**
16	**Expenses at Current Rates**									
17	Fuel Cost	$ 260,192,502	$ 95,354,486	$ 490,897	$ 4,197,442	$ 74,328,965	$ 79,824,130	$ 4,726,711	$ 490,811	$ 779,059
18	Variable Production Cost	18,054,808	6,551,059	34,459	291,427	5,155,612	5,597,499	331,601	36,004	57,149
19	O&M and A&G Expenses	129,424,237	69,018,775	585,070	3,147,651	33,501,407	21,928,446	883,572	27,335	331,981
20	Depreciation and Amortization Expense	171,804,198	84,845,518	519,255	3,618,764	48,259,073	32,309,849	1,175,209	315,271	761,259
21	Taxes Other Than Income	12,300,073	6,163,044	42,736	276,144	3,382,600	2,258,779	82,743	21,060	72,967
22	Deferred Taxes	3,589,036	1,766,303	10,461	76,265	1,011,006	670,373	23,132	7,769	23,728
23	Current Income Tax	11,324,453	4,926,195	6,721	272,806	3,649,891	2,169,906	121,948	82,678	94,310
24	**Total Expenses at Current Rates**	**$ 606,689,307**	**$ 268,625,380**	**$ 1,689,599**	**$ 11,880,498**	**$ 169,288,554**	**$ 144,758,980**	**$ 7,344,917**	**$ 980,926**	**$ 2,120,452**
25	**Operating Income at Current Rates**	**$ 117,233,543**	**$ 50,997,189**	**$ 69,574**	**$ 2,824,151**	**$ 37,784,572**	**$ 22,463,400**	**$ 1,262,433**	**$ 855,901**	**$ 976,322**
26	Current Rate of Return	4.23%	3.78%	0.97%	5.14%	4.77%	4.23%	6.87%	17.46%	8.30%
27	Relative Rate of Return	1.00	0.89	0.23	1.21	1.13	1.00	1.62	4.12	1.96
28	Current Revenue to Cost Ratio	0.90	0.87	0.79	0.93	0.92	0.92	1.02	1.45	1.06
29	Current Parity Ratio	1.00	0.97	0.88	1.03	1.02	1.03	1.13	1.61	1.17
30	**Current Revenue at Equal Rates of Return**									
31	Current Rate of Return	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%	4.23%
32	Current Operating Income at Equal ROR	$ 117,233,543	$ 57,086,639	$ 302,964	$ 2,324,954	$ 33,544,354	$ 22,491,768	$ 777,251	$ 207,497	$ 498,115
33	Current Income Taxes - Equal ROR	11,324,453	5,514,420	29,266	224,584	3,240,297	2,172,646	75,080	20,044	48,117
34	Expenses before Income Tax - Equal ROR	595,364,854	263,110,960	1,660,333	11,655,913	166,048,257	142,586,334	7,269,837	960,883	2,072,336
35	**Revenue at Equal Rates of Return**	**$ 723,922,849**	**$ 325,712,019**	**$ 1,992,563**	**$ 14,205,452**	**$ 202,832,908**	**$ 167,250,748**	**$ 8,122,168**	**$ 1,188,423**	**$ 2,618,568**

CenterPoint Energy Indiana
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Line No.	Category Description	Total System	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
36	**Revenue Requirement at Equal Rates of Return**									
37	Required Return	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%	6.77%
38	Required Operating Income	$ 187,518,958	$ 91,311,982	$ 484,601	$ 3,718,842	$ 53,655,311	$ 35,976,333	$ 1,243,239	$ 331,898	$ 796,752
39	**Expenses at Required Return**									
40	Fuel Cost	$ 246,229,310	$ 90,237,302	$ 464,553	$ 3,972,187	$ 70,340,112	$ 75,540,380	$ 4,473,053	$ 464,471	$ 737,251
41	Variable Production Cost	8,275,422	2,992,105	15,739	133,105	2,358,817	2,579,330	153,779	16,444	26,102
42	O&M and A&G Expenses	139,203,623	72,577,728	603,790	3,305,972	36,298,202	24,946,614	1,061,394	46,894	363,028
43	Depreciation and Amortization Expense	171,804,198	84,845,518	519,255	3,618,764	48,259,073	32,309,849	1,175,209	315,271	761,259
44	Taxes Other Than Income	12,300,073	6,163,044	42,736	276,144	3,382,600	2,258,779	82,743	21,060	72,967
45	Deferred Taxes	3,589,036	1,766,303	10,461	76,265	1,011,006	670,373	23,132	7,769	23,728
46	Current Income Tax	11,324,453	5,514,420	29,266	224,584	3,240,297	2,172,646	75,080	20,044	48,117
47	Gross-up Income Tax	23,267,560	11,330,092	60,130	461,438	6,657,611	4,463,983	154,263	41,182	98,862
48	Gross-up Other Expenses	419,833	204,437	1,085	8,326	120,128	80,547	2,783	743	1,784
49	**Total Expenses at Required Return**	**$ 616,413,508**	**$ 275,630,950**	**$ 1,747,014**	**$ 12,076,786**	**$ 171,667,846**	**$ 145,022,500**	**$ 7,201,438**	**$ 933,878**	**$ 2,133,096**
50	Under Equal Rates of Return									
51	**Total Revenue Requirement at Equal Rates of Re**	**$ 803,932,466**	**$ 366,942,931**	**$ 2,231,616**	**$ 15,795,627**	**$ 225,323,157**	**$ 180,998,832**	**$ 8,444,677**	**$ 1,265,777**	**$ 2,929,848**
52	**Total Revenue (Deficiency)/Surplus**	**$ (80,009,617)**	**$ (47,320,362)**	**$ (472,442)**	**$ (1,090,978)**	**$ (18,250,031)**	**$ (13,776,453)**	**$ 162,673**	**$ 571,051**	**$ 166,926**
53	**Percent Change at Equal Rates of Return**	11.05%	14.81%	26.86%	7.42%	8.81%	8.24%	-1.89%	-31.09%	-5.39%
54	LESS:									
55	Fuel Cost Revenue	260,192,502	95,354,486	490,897	4,197,442	74,328,965	79,824,130	4,726,711	490,811	779,059
56	Decrease in Fuel Cost Revenue	(13,963,192)	(5,117,184)	(26,344)	(225,255)	(3,988,853)	(4,283,750)	(253,658)	(26,339)	(41,808)
57	Variable Production Revenue	6,549,773	2,368,171	12,457	105,349	1,866,940	2,041,470	121,712	13,015	20,659
58	Variable Production Revenue_Special Contract	1,725,649	623,935	3,282	27,756	491,877	537,860	32,067	3,429	5,443
59	Special Contract Revenue	38,066,775	17,375,009	105,669	747,934	10,669,212	8,570,424	399,861	59,935	138,730
60	Other Revenue	8,302,436	3,936,989	23,642	167,081	2,258,390	1,784,036	85,831	15,401	31,067
61	Sale for Resale and Transmission Revenue	30,482,048	13,913,074	84,614	598,910	8,543,393	6,862,784	320,190	47,993	111,089
62	**Total Base Rate Margin Requirement at Equal Ra**	**$ 472,576,476**	**$ 238,488,452**	**$ 1,537,399**	**$ 10,176,410**	**$ 131,153,232**	**$ 85,661,879**	**$ 3,011,962**	**$ 661,531**	**$ 1,885,610**

CenterPoint Energy Indiana
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Line No.	Category Description	Total System	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
63	Under Proposed Revenues									
64	**Total Proposed Revenue Increase/(Decrease)**	**$ 80,009,617**	**$ 46,840,706**	**$ 291,642**	**$ 1,070,331**	**$ 17,955,496**	**$ 13,539,857**	**$ 311,586**	**$ -**	**$ -**
65	**Total Proposed Revenue**	**$ 803,932,466**	**$ 366,463,275**	**$ 2,050,815**	**$ 15,774,980**	**$ 225,028,622**	**$ 180,762,236**	**$ 8,918,936**	**$ 1,836,828**	**$ 3,096,774**
66	LESS:									
67	Fuel Cost Revenue	246,229,310	90,237,302	464,553	3,972,187	70,340,112	75,540,380	4,473,053	464,471	737,251
68	Variable Production Revenue	6,549,773	2,368,171	12,457	105,349	1,866,940	2,041,470	121,712	13,015	20,659
69	Variable Production Revenue_Special Contract	1,725,649	623,935	3,282	27,756	491,877	537,860	32,067	3,429	5,443
70	Special Contract Revenue	38,066,775	17,375,009	105,669	747,934	10,669,212	8,570,424	399,861	59,935	138,730
71	Other Revenue	8,302,436	3,936,989	23,642	167,081	2,258,390	1,784,036	85,831	15,401	31,067
72	Sale for Resale and Transmission Revenue	30,482,048	13,913,074	84,614	598,910	8,543,393	6,862,784	320,190	47,993	111,089
73	**Total Base Rate Margin as Proposed**	**472,576,476**	**238,008,796**	**1,356,598**	**10,155,762**	**130,858,697**	**85,425,283**	**3,486,220**	**1,232,583**	**2,052,536**
74	Percent Margin Change	17.25%	20.89%	23.00%	10.19%	13.53%	15.49%	8.03%	0.00%	0.00%
75	**Operating Income at Proposed Rates**									
76	Gross-up Other Expenses	419,833	245,786	1,530	5,616	94,218	71,047	1,635	-	-
77	Operating Income Prior to Taxes	$ 222,110,971	$ 107,635,488	$ 392,751	$ 4,386,926	$ 63,284,593	$ 42,385,865	$ 1,947,990	$ 964,918	$ 1,112,440
78	Income Taxes	34,592,013	16,763,369	61,168	683,229	9,856,071	6,601,261	303,384	150,278	173,254
79	**Total Operating Income at Proposed Rates**	$ 187,518,958	$ 90,872,118	$ 331,583	$ 3,703,698	$ 53,428,522	$ 35,784,604	$ 1,644,606	$ 814,640	$ 939,186
80	Proposed Rate of Return	6.77%	6.74%	4.63%	6.74%	6.74%	6.73%	8.96%	16.62%	7.98%
81	Relative Rate of Return	1.00	1.00	0.68	1.00	1.00	0.99	1.32	2.45	1.18
82	Proposed Revenue to Cost Ratio	1.00	1.00	0.92	1.00	1.00	1.00	1.06	1.45	1.06
83	Proposed Parity Ratio	1.00	1.00	0.92	1.00	1.00	1.00	1.06	1.45	1.06
84	Class (Subsidies)/Excesses at Current Rates (at equal 4.23% ROR)	$ -	$ (6,089,450)	$ (233,390)	$ 499,197	$ 4,240,218	$ (28,368)	$ 485,181	$ 648,404	$ 478,207
85	Class (Subsidies)/Excesses at Proposed Rates	$ -	$ (479,656)	$ (180,800)	$ (20,648)	$ (294,535)	$ (236,596)	$ 474,259	$ 571,051	$ 166,926
86	Dollar Value of Change in Subsidies	$ -	$ 5,609,794	$ 52,589	$ (519,845)	$ (4,534,754)	$ (208,228)	$ (10,922)	$ (77,353)	$ (311,281)
87	Percent Change in Subsidies		-92%	-23%	-104%	-107%	734%	-2%	-12%	-65%

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
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Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
1	**Functional Rate Base**									
2	**Production**									
3	Demand	$ 1,323,048,488	$ 602,181,695	$ 2,035,043	$ 22,336,433	$ 396,173,274	$ 286,853,492	$ 13,468,551	$ -	$ -
4	Energy	$ 8,990,701	$ 3,223,242	$ 16,954	$ 143,387	$ 2,541,688	$ 2,845,268	$ 174,329	$ 17,715	$ 28,118
5	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Subtotal	$ 1,332,039,189	$ 605,404,937	$ 2,051,998	$ 22,479,821	$ 398,714,962	$ 289,698,760	$ 13,642,879	$ 17,715	$ 28,118
7	**Transmission**									
8	Demand	$ 446,145,668	$ 203,061,911	$ 686,238	$ 7,532,077	$ 133,593,736	$ 96,729,972	$ 4,541,735	$ -	$ -
9	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Subtotal	$ 446,145,668	$ 203,061,911	$ 686,238	$ 7,532,077	$ 133,593,736	$ 96,729,972	$ 4,541,735	$ -	$ -
12	**Substation**									
13	Demand	$ 222,157,224	$ 109,738,272	$ 468,762	$ 3,892,082	$ 62,783,203	$ 44,058,948	$ 24,187	$ 460,625	$ 731,145
14	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16	Subtotal	$ 222,157,224	$ 109,738,272	$ 468,762	$ 3,892,082	$ 62,783,203	$ 44,058,948	$ 24,187	$ 460,625	$ 731,145
17	**Dist Primary**									
18	Demand	$ 481,469,100	$ 237,449,082	$ 1,014,422	$ 8,432,560	$ 136,073,813	$ 95,798,250	$ 149,412	$ 986,190	$ 1,565,371
19	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
20	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
21	Subtotal	$ 481,469,100	$ 237,449,082	$ 1,014,422	$ 8,432,560	$ 136,073,813	$ 95,798,250	$ 149,412	$ 986,190	$ 1,565,371
22	**Dist Secondary**									
23	Demand	$ 122,983,800	$ 75,355,932	$ 321,872	$ 2,670,769	$ 43,812,206	$ -	$ -	$ 318,102	$ 504,920
24	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
26	Subtotal	$ 122,983,800	$ 75,355,932	$ 321,872	$ 2,670,769	$ 43,812,206	$ -	$ -	$ 318,102	$ 504,920
27	**Transformation**									
28	Demand	$ 22,803,498	$ 11,273,912	$ 48,155	$ 399,571	$ 6,444,244	$ 4,514,485	$ -	$ 47,591	$ 75,540
29	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
30	Customer	$ 29,066,466	$ 24,891,405	$ 599,934	$ 1,850,775	$ 1,724,352	$ -	$ -	$ -	$ -
31	Subtotal	$ 51,869,964	$ 36,165,316	$ 648,089	$ 2,250,346	$ 8,168,597	$ 4,514,485	$ -	$ 47,591	$ 75,540

Cause No. 45990
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Line	Description	TOTAL	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
32	**Onsite & Metering**									
33	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
34	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
35	Customer	$ 89,519,390	$ 72,011,953	$ 1,735,635	$ 6,960,755	$ 8,730,118	$ 80,172	$ 756	$ -	$ -
36	Subtotal	$ 89,519,390	$ 72,011,953	$ 1,735,635	$ 6,960,755	$ 8,730,118	$ 80,172	$ 756	$ -	$ -
37	**Lighting Plant**									
38	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
39	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
40	Customer	$ 11,934,666	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,072,263	$ 8,862,403
41	Subtotal	$ 11,934,666	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,072,263	$ 8,862,403
42	**Customer Accounts & Service**									
43	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
44	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
45	Customer	$ 11,732,664	$ 9,586,332	$ 231,050	$ 712,782	$ 668,584	$ 527,576	$ 4,977	$ -	$ 1,364
46	Subtotal	$ 11,732,664	$ 9,586,332	$ 231,050	$ 712,782	$ 668,584	$ 527,576	$ 4,977	$ -	$ 1,364
47	**Total**									
48	Demand	$ 2,618,607,778	$ 1,239,060,803	$ 4,574,492	$ 45,263,492	$ 778,880,477	$ 527,955,146	$ 18,183,885	$ 1,812,507	$ 2,876,976
49	Energy	$ 8,990,701	$ 3,223,242	$ 16,954	$ 143,387	$ 2,541,688	$ 2,845,268	$ 174,329	$ 17,715	$ 28,118
50	Customer	$ 142,253,186	$ 106,489,689	$ 2,566,619	$ 9,524,312	$ 11,123,054	$ 607,749	$ 5,733	$ 3,072,263	$ 8,863,767
51	**TOTAL RATE BASE**	$ 2,769,851,666	$ 1,348,773,734	$ 7,158,066	$ 54,931,192	$ 792,545,219	$ 531,408,163	$ 18,363,947	$ 4,902,484	$ 11,768,861

52 **Functional Revenue Requirement**

Line	Description	TOTAL	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
53	**Production**									
54	Demand	$ 273,209,008	$ 124,350,290	$ 420,236	$ 4,612,465	$ 81,809,630	$ 59,235,137	$ 2,781,251	$ -	$ -
55	Energy	$ 723,660	$ 259,438	$ 1,365	$ 11,541	$ 204,580	$ 229,015	$ 14,032	$ 1,426	$ 2,263
56	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
57	Subtotal	$ 273,932,668	$ 124,609,728	$ 421,600	$ 4,624,006	$ 82,014,210	$ 59,464,152	$ 2,795,282	$ 1,426	$ 2,263
58	**Transmission**									
59	Demand	$ 85,499,091	$ 38,914,664	$ 131,510	$ 1,443,443	$ 25,601,824	$ 18,537,274	$ 870,375	$ -	$ -
60	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
61	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
62	Subtotal	$ 85,499,091	$ 38,914,664	$ 131,510	$ 1,443,443	$ 25,601,824	$ 18,537,274	$ 870,375	$ -	$ -
63	**Substation**									
64	Demand	$ 25,791,481	$ 12,677,309	$ 54,174	$ 451,435	$ 7,290,050	$ 5,166,502	$ 18,817	$ 51,480	$ 81,714
65	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
66	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
67	Subtotal	$ 25,791,481	$ 12,677,309	$ 54,174	$ 451,435	$ 7,290,050	$ 5,166,502	$ 18,817	$ 51,480	$ 81,714

Cause No. 45990

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18, Attachment JDT-2: Allocated Cost of Service Study
Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class

Line	Description	TOTAL	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
68	**Dist Primary**									
69	Demand	$ 92,126,969	$ 45,040,419	$ 192,551	$ 1,610,907	$ 26,044,620	$ 18,653,579	$ 129,094	$ 176,169	$ 279,631
70	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
71	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
72	Subtotal	$ 92,126,969	$ 45,040,419	$ 192,551	$ 1,610,907	$ 26,044,620	$ 18,653,579	$ 129,094	$ 176,169	$ 279,631
73	**Dist Secondary**									
74	Demand	$ 19,676,111	$ 12,056,155	$ 51,496	$ 427,295	$ 7,009,491	$ -	$ -	$ 50,893	$ 80,782
75	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
76	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
77	Subtotal	$ 19,676,111	$ 12,056,155	$ 51,496	$ 427,295	$ 7,009,491	$ -	$ -	$ 50,893	$ 80,782
78	**Transformation**									
79	Demand	$ 3,052,724	$ 1,509,248	$ 6,447	$ 53,491	$ 862,696	$ 604,358	$ -	$ 6,371	$ 10,113
80	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
81	Customer	$ 3,891,153	$ 3,332,234	$ 80,314	$ 247,765	$ 230,840	$ -	$ -	$ -	$ -
82	Subtotal	$ 6,943,876	$ 4,841,482	$ 86,760	$ 301,256	$ 1,093,537	$ 604,358	$ -	$ 6,371	$ 10,113
83	**Onsite & Metering**									
84	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
85	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
86	Customer	$ 35,321,723	$ 28,891,585	$ 696,346	$ 2,471,403	$ 3,232,265	$ 29,842	$ 282	$ -	$ -
87	Subtotal	$ 35,321,723	$ 28,891,585	$ 696,346	$ 2,471,403	$ 3,232,265	$ 29,842	$ 282	$ -	$ -
88	**Lighting Plant**									
89	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
90	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
91	Customer	$ 2,209,879	$ -	$ -	$ -	$ -	$ -	$ -	$ 498,522	$ 1,711,357
92	Subtotal	$ 2,209,879	$ -	$ -	$ -	$ -	$ -	$ -	$ 498,522	$ 1,711,357
93	**Customer Accounts & Service**									
94	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
95	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
96	Customer	$ 7,925,936	$ 6,682,183	$ 116,886	$ 360,591	$ 338,231	$ 423,416	$ 3,994	$ -	$ 635
97	Subtotal	$ 7,925,936	$ 6,682,183	$ 116,886	$ 360,591	$ 338,231	$ 423,416	$ 3,994	$ -	$ 635
98	**Total**									
99	Demand	$ 499,355,383	$ 234,548,085	$ 856,413	$ 8,599,035	$ 148,618,311	$ 102,196,850	$ 3,799,537	$ 284,913	$ 452,240
100	Energy	$ 723,660	$ 259,438	$ 1,365	$ 11,541	$ 204,580	$ 229,015	$ 14,032	$ 1,426	$ 2,263
101	Customer	$ 49,348,691	$ 38,906,001	$ 893,546	$ 3,079,759	$ 3,801,336	$ 453,258	$ 4,276	$ 498,522	$ 1,711,993
102	TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN	$ 549,427,734	$ 273,713,524	$ 1,751,324	$ 11,690,335	$ 152,624,228	$ 102,879,123	$ 3,817,844	$ 784,861	$ 2,166,495
103	Demand	90.89%	85.69%	48.90%	73.56%	97.38%	99.34%	99.52%	36.30%	20.87%
104	Energy	0.13%	0.09%	0.08%	0.10%	0.13%	0.22%	0.37%	0.18%	0.10%
105	Customer	8.98%	14.21%	51.02%	26.34%	2.49%	0.44%	0.11%	63.52%	79.02%

CenterPoint Energy Indiana
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Line	Description	TOTAL	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
106	**Unit Costs**									
107	**Production**									
108	Demand	$ -	$ -	$ -	$ -	$ 25.09	$ 21.92	$ 28.58	$ -	$ -
109	Energy	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00	$ 0.00
110	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
111	**Transmission**									
112	Demand	$ -	$ -	$ -	$ -	$ 7.85	$ 6.86	$ 8.94	$ -	$ -
113	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
114	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
115	**Substation**									
116	Demand	$ -	$ -	$ -	$ -	$ 2.24	$ 1.91	$ 0.19	$ -	$ -
117	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
118	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
119	**Dist Primary**									
120	Demand	$ -	$ -	$ -	$ -	$ 7.99	$ 6.90	$ 1.33	$ -	$ -
121	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
122	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
123	**Dist Secondary**									
124	Demand	$ -	$ -	$ -	$ -	$ 2.15	$ -	$ -	$ -	$ -
125	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
126	Customer	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

CenterPoint Energy Indiana
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Line	Description	TOTAL	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
127	**Transformation**									
128	Demand	$ -	$ -	$ -	$ -	$ 0.26	$ 0.22	$ -	$ -	$ -
129	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
130	Customer	$ 2.08	$ 2.08	$ 2.08	$ 2.08	$ 2.06	$ -	$ -	$ -	$ -
131	**Onsite & Metering**									
132	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
133	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
134	Customer	$ 18.85	$ 18.02	$ 18.02	$ 20.74	$ 28.91	$ 23.46	$ 23.46	$ -	$ -
135	**Lighting Plant**									
136	Demand	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
137	Energy	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
138	Customer	$ 1.18	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 7,505.95
139	**Total**									
140	Energy	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002	$ 0.0002
141	Customer (per cust month)	$ 26.33	$ 24.27	$ 23.13	$ 25.84	$ 34.00	$ 356.33	$ 356.33	$ -	$ 7,508.74
142	Onsite and Customer Services	$ 3.26	$ 20.10	$ 20.10	$ 22.81	$ 30.98	$ 23.46	$ 23.46	$ -	$ -
143	Demand & Customer (per cust month)	$ 292.79	$ 170.60	$ 45.30	$ 97.99	$ 1,363.40	$ 80,699.77	$ 316,984.39	$ -	$ 9,492.25
144	Demand		$ -	$ -	$ -	$ 45.58	$ 37.81	$ 39.04	$ -	$ -
145	**BILLING DETERMINANTS**									
146	Demand		0	0	0	3,260,842	2,702,812	97,323	0	0
147	Energy	3,904,507,404	1,399,798,865	7,362,997	62,270,627	1,103,811,583	1,235,650,954	75,708,000	7,693,136	12,211,243
148	Customers (Number of Bills)	1,874,048	1,602,925	38,634	119,184	111,793	1,272	12	0	228

Cause No. 45990

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential (RS)	Water Heating (B)	Small General Service (SGS)
1	**RATE BASE**					
2	**Plant in Service**					
3	**Intangible Plant**					
4	Organization	301	12,151	6,459	65	323
5	Franchises and Consents	302	-	-	-	-
6	Miscellaneous Intangible Plant	303	198,547,734	105,538,977	1,069,960	5,273,049
7	Subtotal - Intangible Plant		198,559,885	105,545,436	1,070,025	5,273,372
8	**Steam Production Plant**					
9	Land and Land Rights	310	1,976,433	899,568	3,040	33,367
10	Structures and Improvements	311	96,772,607	44,045,772	148,851	1,633,768
11	Boiler Plant Equipment	312	569,693,573	259,294,383	876,273	9,617,881
12	Engines and Engine Driven Generators	313	-	-	-	-
13	Turbogenerator Units	314	48,177,832	21,928,001	74,105	813,365
14	Accessory Electric Equipment	315	33,226,393	15,122,897	51,107	560,946
15	Miscellaneous Power Plant Equipment	316	24,639,884	11,214,772	37,900	415,984
16	Asset Retirement Costs for Steam Production	317	-	-	-	-
17	Subtotal - Steam Production Plant		774,486,722	352,505,393	1,191,275	13,075,311
18	**Other Production Plant**					
19	Land and Land Rights	340	389,504	177,282	599	6,576
20	Structures and Improvements	341	2,271,907	1,034,052	3,495	38,356
21	Fuel Holders, Producers and Accessories	342	4,101,467	1,866,771	6,309	69,243
22	Prime Movers	343	48,262,971	21,966,752	74,236	814,802
23	Generators	344	17,496,247	7,963,366	26,912	295,381
24	Accessory Electric Equipment	345	5,263,501	2,395,667	8,096	88,861
25	Miscellaneous Power Plant Equipment	346	777,314,426	353,792,414	1,195,624	13,123,050
26	Asset Retirement Costs for Other Production	347	-	-	-	-
27	Subtotal - Other Production Plant		855,100,022	389,196,303	1,315,270	14,436,270
28	**Transmission Plant**					
29	Land and Land Rights	350	19,334,962	8,800,252	29,740	326,423
30	Structures and Improvements	352	6,442,051	2,932,081	9,909	108,758
31	Station Equipment	353	196,875,807	89,607,455	302,824	3,323,766
32	Towers and Fixtures	354	4,622,707	2,104,012	7,110	78,043
33	Poles and Fixtures	355	237,797,966	108,233,057	365,768	4,014,636
34	Overhead Conductors and Devices	356	106,793,870	48,606,921	164,265	1,802,953
35	Underground Conduit	357	1,180,974	537,517	1,817	19,938
36	Underground Conductors and Devices	358	1,356,646	617,473	2,087	22,904
37	Road and Trails	359	-	-	-	-
38	ARO for Transmission Plant	359.1	-	-	-	-
39	Subtotal - Transmission Plant		574,404,982	261,438,767	883,519	9,697,421

Line No.	Account Description	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
1	**RATE BASE**					
2	**Plant in Service**					
3	**Intangible Plant**					
4	Organization	3,064	2,101	93	2	44
5	Franchises and Consents	-	-	-	-	-
6	Miscellaneous Intangible Plant	50,062,369	34,326,702	1,527,001	32,757	716,918
7	Subtotal - Intangible Plant	50,065,433	34,328,803	1,527,095	32,759	716,962
8	**Steam Production Plant**					
9	Land and Land Rights	591,823	428,516	20,120	-	-
10	Structures and Improvements	28,977,563	20,981,514	985,139	-	-
11	Boiler Plant Equipment	170,588,886	123,516,706	5,799,445	-	-
12	Engines and Engine Driven Generators	-	-	-	-	-
13	Turbogenerator Units	14,426,357	10,445,558	490,447	-	-
14	Accessory Electric Equipment	9,949,302	7,203,898	338,243	-	-
15	Miscellaneous Power Plant Equipment	7,378,160	5,342,236	250,832	-	-
16	Asset Retirement Costs for Steam Production	-	-	-	-	-
17	Subtotal - Steam Production Plant	231,912,090	167,918,427	7,884,226	-	-
18	**Other Production Plant**					
19	Land and Land Rights	116,633	84,449	3,965	-	-
20	Structures and Improvements	680,299	492,578	23,128	-	-
21	Fuel Holders, Producers and Accessories	1,228,142	889,249	41,753	-	-
22	Prime Movers	14,451,851	10,464,017	491,314	-	-
23	Generators	5,239,071	3,793,406	178,111	-	-
24	Accessory Electric Equipment	1,576,101	1,141,193	53,582	-	-
25	Miscellaneous Power Plant Equipment	232,758,817	168,531,508	7,913,012	-	-
26	Asset Retirement Costs for Other Production	-	-	-	-	-
27	Subtotal - Other Production Plant	256,050,915	185,396,401	8,704,865	-	-
28	**Transmission Plant**					
29	Land and Land Rights	5,789,656	4,192,062	196,829	-	-
30	Structures and Improvements	1,929,006	1,396,717	65,580	-	-
31	Station Equipment	58,952,437	42,685,142	2,004,183	-	-
32	Towers and Fixtures	1,384,222	1,002,261	47,059	-	-
33	Poles and Fixtures	71,206,157	51,557,579	2,420,768	-	-
34	Overhead Conductors and Devices	31,978,327	23,154,249	1,087,155	-	-
35	Underground Conduit	353,630	256,050	12,022	-	-
36	Underground Conductors and Devices	406,234	294,138	13,811	-	-
37	Road and Trails	-	-	-	-	-
38	ARO for Transmission Plant	-	-	-	-	-
39	Subtotal - Transmission Plant	171,999,669	124,538,198	5,847,407	-	-

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Line No.	Account Description	FERC Account	Account Balance	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
40	**Distribution Plant**										
41	Land and land rights	360	3,081,457	1,554,237	6,639	55,085	889,974	558,546	-	6,561	10,414
42	Structures and improvements	361	1,539,531	780,794	3,335	27,673	447,304	271,897	-	3,296	5,232
43	Station equipment	362	259,931,734	128,508,679	548,906	4,554,612	73,456,434	51,459,558	-	542,476	861,068
44	Storage battery equipment	363	-	-	-	-	-	-	-	-	-
45	Poles, Towers and Fixtures - PRI DEM	364	250,802,380	123,995,182	529,627	4,394,644	70,876,489	49,652,190	-	523,423	830,825
46	Poles, Towers and Fixtures - PRI CUST	364	-	-	-	-	-	-	-	-	-
47	Poles, Towers and Fixtures - SEC DEM	364	47,052,112	28,830,267	123,144	1,021,804	16,762,020	-	-	121,702	193,176
48	Poles, Towers and Fixtures - SEC CUST	364	-	-	-	-	-	-	-	-	-
49	Overhead Conductors and Devices - PRI DEM	365	265,280,976	131,153,312	560,202	4,648,343	74,968,125	52,518,566	-	553,640	878,788
50	Overhead Conductors and Devices - PRI CUST	365	-	-	-	-	-	-	-	-	-
51	Overhead Conductors and Devices - SEC DEM	365	46,814,290	28,684,546	122,522	1,016,639	16,677,297	-	-	121,087	192,200
52	Overhead Conductors and Devices - SEC CUST	365	-	-	-	-	-	-	-	-	-
53	Underground conduit	366	47,676,074	25,658,238	109,595	909,381	14,772,313	5,946,313	-	108,312	171,922
54	Underground Conductors and Devices - PRI DEM	367	104,053,705	51,443,523	219,733	1,823,264	29,405,467	20,599,861	-	217,160	344,695
55	Underground Conductors and Devices - PRI CUST	367	-	-	-	-	-	-	-	-	-
56	Underground Conductors and Devices - SEC DEM	367	61,110,906	37,444,519	159,939	1,327,111	21,770,376	-	-	158,065	250,896
57	Underground Conductors and Devices - SEC CUST	367	-	-	-	-	-	-	-	-	-
58	Transformers and Transformer Installations - DEM	368	45,332,193	22,411,962	95,729	794,326	12,810,830	8,974,567	-	94,608	150,171
59	Transformers and Transformer Installations - CUST	368	57,782,655	49,482,846	1,192,638	3,679,247	3,427,924	-	-	-	-
60	Services	369	103,266,723	78,847,006	1,900,374	10,461,700	11,948,298	108,324	1,022	-	-
61	Meters	370	26,328,799	21,810,074	525,667	1,684,243	2,287,399	21,216	200	-	-
62	Installations on customers premises	371	5,941,020	-	-	-	-	-	-	5,941,020	-
63	Street lighting and signal systems	373	20,653,277	-	-	-	-	-	-	-	20,653,277
64	Subtotal - Distribution Plant		1,346,647,831	730,605,185	6,098,051	36,398,072	350,500,249	190,111,038	1,222	8,391,350	24,542,663
65	**General Plant**										
66	Land and Land Rights	389	2,309,376	1,227,560	12,445	61,333	582,292	399,266	17,761	381	8,339
67	Structures and Improvements	390	56,222,863	29,885,526	302,981	1,493,172	14,176,186	9,720,310	432,402	9,276	203,010
68	Office Furniture and Equipment	391	23,986,173	12,749,962	129,260	637,027	6,047,939	4,146,943	184,474	3,957	86,610
69	Transportation Equipment	392	25,161,795	13,374,870	135,595	668,249	6,344,364	4,350,195	193,516	4,151	90,854
70	Stores Equipment	393	688,773	366,120	3,712	18,292	173,669	119,081	5,297	114	2,487
71	Tools, Shop and Garage Equipment	394	9,246,944	4,915,256	49,831	245,581	2,331,550	1,598,694	71,117	1,526	33,389
72	Laboratory Equipment	395	1,859,238	988,287	10,019	49,378	468,793	321,442	14,299	307	6,713
73	Power Operated Equipment	396	5,812,993	3,089,924	31,326	154,382	1,465,704	1,005,002	44,707	959	20,990
74	Communication Equipment	397	22,869,808	12,156,553	123,244	607,378	5,766,456	3,953,936	175,888	3,773	82,579
75	Miscellaneous Equipment	398	2,761,879	1,468,090	14,884	73,350	696,388	477,498	21,241	456	9,973
76	Miscellaneous Equipment-DLC	398	3,078,597	1,401,214	4,735	51,975	921,854	667,478	31,340	-	-
77	Subtotal - General Plant		153,998,437	81,623,362	818,032	4,060,118	38,975,196	26,759,846	1,192,042	24,899	544,943
78	**Total Plant in Service**		3,903,197,879	1,920,914,445	11,376,172	82,940,564	1,099,503,552	729,052,713	25,156,856	8,449,008	25,804,568

Cause No. 45990

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
79	**Accumulated Depreciation & Amortization**										
80	**Intangible Plant**										
81	Organization	301	-	21,810,074	525,667	1,684,243	2,287,399	21,216	200	-	-
82	Franchises and Consents	302	-	-	-	-	-	-	-	-	-
83	Miscellaneous Intangible Plant	303	(120,558,306)	(64,083,332)	(649,680)	(3,201,799)	(30,397,901)	(20,843,195)	(927,196)	(19,890)	(435,313)
84	Subtotal - Intangible Plant		(120,558,306)	(64,083,332)	(649,680)	(3,201,799)	(30,397,901)	(20,843,195)	(927,196)	(19,890)	(435,313)
				-	-	-	-	-	-	-	-
85	Steam Production Plant			-	-	-	-	-	-	-	-
86	Land and Land Rights	310	142,880	65,032	220	2,412	42,784	30,978	1,455	-	-
87	Structures and Improvements	311	(46,698,062)	(21,254,488)	(71,828)	(788,382)	(13,983,255)	(10,124,725)	(475,383)	-	-
88	Boiler Plant Equipment	312	(264,424,780)	(120,352,174)	(406,724)	(4,464,165)	(79,179,283)	(57,330,606)	(2,691,828)	-	-
89	Engines and Engine Driven Generators	313	-	-	-	-	-	-	-	-	-
90	Turbogenerator Units	314	(36,101,462)	(16,431,476)	(55,529)	(609,485)	(10,810,212)	(7,827,249)	(367,511)	-	-
91	Accessory Electric Equipment	315	(3,420,234)	(1,556,710)	(5,261)	(57,742)	(1,024,154)	(741,550)	(34,818)	-	-
92	Miscellaneous Power Plant Equipment	316	(8,721,704)	(3,969,659)	(13,415)	(147,245)	(2,611,625)	(1,890,975)	(88,786)	-	-
93	Asset Retirement Costs for Steam Production	317	-	-	-	-	-	-	-	-	-
94	Subtotal - Steam Production Plant		(359,223,363)	(163,499,475)	(552,538)	(6,064,607)	(107,565,745)	(77,884,127)	(3,656,871)	-	-
				-	-	-	-	-	-	-	-
95	Other Production Plant			-	-	-	-	-	-	-	-
96	Land and Land Rights	340	38,004	17,297	58	642	11,380	8,240	387	-	-
97	Structures and Improvements	341	(2,231,173)	(1,015,512)	(3,432)	(37,668)	(668,102)	(483,746)	(22,713)	-	-
98	Fuel Holders, Producers and Accessories	342	(4,631,843)	(2,108,170)	(7,124)	(78,197)	(1,386,958)	(1,004,242)	(47,152)	-	-
99	Prime Movers	343	(42,171,802)	(19,194,374)	(64,866)	(711,968)	(12,627,913)	(9,143,375)	(429,306)	-	-
100	Generators	344	(13,256,606)	(6,033,706)	(20,391)	(223,805)	(3,969,554)	(2,874,198)	(134,951)	-	-
101	Accessory Electric Equipment	345	(4,116,286)	(1,873,516)	(6,331)	(69,493)	(1,232,580)	(892,462)	(41,904)	-	-
102	Miscellaneous Power Plant Equipment	346	(16,512,384)	(7,515,564)	(25,398)	(278,771)	(4,944,464)	(3,580,092)	(168,095)	-	-
103	Asset Retirement Costs for Other Production	347	-	-	-	-	-	-	-	-	-
104	Subtotal - Other Production Plant		(82,882,091)	(37,723,544)	(127,485)	(1,399,261)	(24,818,190)	(17,969,876)	(843,734)	-	-
				-	-	-	-	-	-	-	-
105	Transmission Plant			-	-	-	-	-	-	-	-
106	Land and Land Rights	350	(4,213,024)	(1,917,546)	(6,480)	(71,127)	(1,261,547)	(913,436)	(42,888)	-	-
107	Structures and Improvements	352	(2,543,412)	(1,157,626)	(3,912)	(42,939)	(761,598)	(551,443)	(25,892)	-	-
108	Station Equipment	353	(55,183,260)	(25,116,501)	(84,880)	(931,634)	(16,524,060)	(11,964,422)	(561,762)	-	-
109	Towers and Fixtures	354	(5,214,294)	(2,373,271)	(8,020)	(88,031)	(1,561,367)	(1,130,524)	(53,081)	-	-
110	Poles and Fixtures	355	(55,473,356)	(25,248,538)	(85,326)	(936,532)	(16,610,926)	(12,027,319)	(564,715)	-	-
111	Overhead Conductors and Devices	356	(27,944,809)	(12,718,999)	(42,983)	(471,780)	(8,367,786)	(6,058,785)	(284,476)	-	-
112	Underground Conduit	357	(968,589)	(440,850)	(1,490)	(16,352)	(290,034)	(210,002)	(9,860)	-	-
113	Underground Conductors and Devices	358	(1,294,260)	(589,079)	(1,991)	(21,850)	(387,553)	(280,612)	(13,175)	-	-
114	Road and Trails	359	-	-	-	-	-	-	-	-	-
115	ARO for Transmission Plant	359.1	-	-	-	-	-	-	-	-	-
116	Subtotal - Transmission Plant		(152,835,002)	(69,562,409)	(235,083)	(2,580,245)	(45,764,871)	(33,136,544)	(1,555,851)	-	-

CenterPoint Energy Indiana
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Line No.	Account Description	FERC Account	Account Balance	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
				-	-	-	-	-	-	-	-
117	Distribution Plant			-	-	-	-	-	-	-	-
118	Land and land rights	360	(20,815)	(10,499)	(45)	(372)	(6,012)	(3,773)	-	(44)	(70)
119	Structures and improvements	361	(897,293)	(455,074)	(1,944)	(16,129)	(260,705)	(158,471)	-	(1,921)	(3,049)
120	Station equipment	362	(44,601,013)	(22,050,471)	(94,185)	(781,514)	(12,604,199)	(8,829,812)	-	(93,082)	(147,748)
121	Storage battery equipment	363	-	-	-	-	-	-	-	-	-
122	Poles, Towers and Fixtures	364	(90,761,034)	(46,568,362)	(198,910)	(1,650,478)	(26,704,857)	(15,129,817)	-	(196,580)	(312,030)
123	Overhead Conductors and Devices	365	(91,322,510)	(46,770,316)	(199,773)	(1,657,636)	(26,816,459)	(15,367,510)	-	(197,432)	(313,383)
124	Underground conduit	366	(18,345,845)	(9,873,340)	(42,173)	(349,931)	(5,684,415)	(2,288,153)	-	(41,679)	(66,156)
125	Underground Conductors and Devices	367	(51,477,871)	(27,704,283)	(118,335)	(981,897)	(15,950,290)	(6,420,486)	-	(116,949)	(185,632)
126	Transformers and Transformer Installations	368	(52,561,797)	(36,647,684)	(656,733)	(2,280,361)	(8,277,548)	(4,574,699)	-	(48,226)	(76,548)
127	Services	369	(71,529,816)	(54,614,998)	(1,316,333)	(7,246,511)	(8,276,234)	(75,033)	(708)	-	-
128	Meters	370	(2,976,324)	(2,465,507)	(59,424)	(190,394)	(258,578)	(2,398)	(23)	-	-
129	Installations on customers premises	371	(2,944,632)	-	-	-	-	-	-	(2,944,632)	-
130	Street lighting and signal systems	373	(12,598,490)	-	-	-	-	-	-	-	(12,598,490)
131	Subtotal - Distribution Plant		(440,037,441)	(247,160,534)	(2,687,853)	(15,155,224)	(104,839,296)	(52,850,152)	(730)	(3,640,545)	(13,703,106)
				-	-	-	-	-	-	-	-
132	General Plant			-	-	-	-	-	-	-	-
133	Land and Land Rights	389	(22,147)	(11,772)	(119)	(588)	(5,584)	(3,829)	(170)	(4)	(80)
134	Structures and Improvements	390	(17,518,991)	(9,312,302)	(94,409)	(465,271)	(4,417,286)	(3,028,839)	(134,736)	(2,890)	(63,258)
135	Office Furniture and Equipment	391	(15,258,932)	(8,110,957)	(82,229)	(405,248)	(3,847,429)	(2,638,100)	(117,354)	(2,517)	(55,097)
136	Transportation Equipment	392	(16,726,737)	(8,891,175)	(90,139)	(444,230)	(4,217,525)	(2,891,867)	(128,643)	(2,760)	(60,397)
137	Stores Equipment	393	(574,962)	(305,624)	(3,098)	(15,270)	(144,972)	(99,404)	(4,422)	(95)	(2,076)
138	Tools, Shop and Garage Equipment	394	(2,180,271)	(1,158,933)	(11,749)	(57,904)	(549,739)	(376,945)	(16,768)	(360)	(7,873)
139	Laboratory Equipment	395	(1,935,880)	(1,029,026)	(10,432)	(51,413)	(488,118)	(334,692)	(14,889)	(319)	(6,990)
140	Power Operated Equipment	396	(2,361,451)	(1,255,240)	(12,726)	(62,716)	(595,423)	(408,269)	(18,162)	(390)	(8,527)
141	Communication Equipment	397	(9,472,725)	(5,035,271)	(51,048)	(251,578)	(2,388,479)	(1,637,729)	(72,853)	(1,563)	(34,204)
142	Miscellaneous Equipment	398	(480,682)	(255,509)	(2,590)	(12,766)	(121,200)	(83,105)	(3,697)	(79)	(1,736)
143	Miscellaneous Equipment-DLC	398	(5,512,812)	(2,509,141)	(8,480)	(93,070)	(1,650,755)	(1,195,247)	(56,120)	-	-
144	Subtotal - General Plant		(72,045,589)	(37,874,949)	(367,020)	(1,860,054)	(18,426,511)	(12,698,026)	(567,814)	(10,977)	(240,237)
				-	-	-	-	-	-	-	-
145	**Total Accumulated Depreciation & Amortization**		(1,227,581,792)	(619,904,244)	(4,619,659)	(30,261,189)	(331,812,514)	(215,381,920)	(7,552,197)	(3,671,412)	(14,378,656)
146	**Other Rate Base Items**										
147	Fuel Stock & Expense	151	8,990,701	3,223,242	16,954	143,387	2,541,688	2,845,268	174,329	17,715	28,118
148	Materials and Supplies (Generation Inventory)	154	41,360,961	18,825,322	63,619	698,279	12,385,115	8,967,575	421,052	-	-
149	Allowance Inventory	158	-	-	-	-	-	-	-	-	-
150	Stores Expense	163	311,332	153,218	907	6,616	87,700	58,152	2,007	674	2,058
151	PISCC - AMI	182.3	10,585,830	9,054,353	218,228	673,227	631,482	7,185	68	-	1,288
152	PISCC - ECA	182.3	5,575,984	2,537,893	8,577	94,137	1,669,671	1,208,943	56,763	-	-
153	PISCC - CECA	182.3	2,963,459	1,348,810	4,558	50,031	887,377	642,515	30,168	-	-
154	PISCC - TDSIC	182.3	21,951,124	11,484,563	84,869	543,999	5,903,691	3,466,528	49,491	106,499	311,485
155	PISCC - CT	182.3	2,496,186	1,136,132	3,840	42,142	747,457	541,204	25,411	-	-
156	Total Other Rate Base Items		94,235,578	47,763,533	401,553	2,251,817	24,854,181	17,737,370	759,288	124,888	342,949
157	**TOTAL RATE BASE**		2,769,851,666	1,348,773,734	7,158,066	54,931,192	792,545,219	531,408,163	18,363,947	4,902,484	11,768,861

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158	**OPERATION AND MAINTENANCE EXPENSE**										
159	**Generation Production, Transmission, and Distribution Expense**										
160	**Steam Power Generation Operation Expenses**										
161	Operation Supervision and Engineering	500	743,496	338,400	1,144	12,552	222,632	161,199	7,569	-	-
162	Fuel	501	246,229,310	90,237,302	464,553	3,972,187	70,340,112	75,540,380	4,473,053	464,471	737,251
163	Fuel (Operation Related Expenses)	501	2,240,456	1,019,737	3,446	37,825	670,882	485,759	22,808	-	-
164	Steam Expenses	502	1,969,108	896,234	3,029	33,244	589,629	426,927	20,045	-	-
165	Steam Expenses - VPC	502	7,310,722	2,643,303	13,904	117,588	2,083,840	2,278,647	135,853	14,527	23,059
166	Electric Expenses	505	1,348,774	613,890	2,075	22,771	403,876	292,431	13,730	-	-
167	Electric Expenses - VPC	505	165,000	59,658	314	2,654	47,031	51,428	3,066	328	520
168	Miscellaneous Steam Power Expenses	506	2,163,147	984,550	3,327	36,519	647,732	468,997	22,021	-	-
169	Miscellaneous Steam Power Expenses - VPC	506	299,500	108,289	570	4,817	85,369	93,350	5,566	595	945
170	Rents	507	-	-	-	-	-	-	-	-	-
171	Allowances	509	-	-	-	-	-	-	-	-	-
172	Subtotal - Steam Power Generation Operation Expenses		262,469,512	96,901,364	492,361	4,240,157	75,091,104	79,799,118	4,703,711	479,922	761,775
173	**Steam Power Generation Maintenance Expenses**										
174	Maintenance Supervision and Engineering	510	492,730	224,265	758	8,319	147,543	106,830	5,016	-	-
175	Maintenance of Structures	511	1,494,465	680,202	2,299	25,230	447,502	324,019	15,214	-	-
176	Maintenance of Boiler Plant	512	6,725,481	3,061,083	10,345	113,543	2,013,876	1,458,169	68,465	-	-
177	Maintenance of Boiler Plant-VPC	512	500,200	180,855	951	8,045	142,576	155,905	9,295	994	1,578
178	Maintenance of Electric Plant	513	3,512,286	1,598,607	5,402	59,296	1,051,718	761,508	35,755	-	-
179	Maintenance of Miscellaneous Steam Plant	514	1,506,822	685,825	2,318	25,439	451,202	326,698	15,339	-	-
180	Subtotal - Steam Power Generation Maintenance Expenses		14,231,984	6,430,837	22,073	239,873	4,254,418	3,133,128	149,084	994	1,578
181	**Other Power Generation Operation Expenses**										
182	Operations Supervision and Engineering	546	20,563	9,359	32	347	6,157	4,458	209	-	-
183	Generation Expenses	548	5,608,351	2,552,625	8,626	94,683	1,679,363	1,215,961	57,093	-	-
184	Miscellaneous Other Power Generation Expenses	549	917,282	417,498	1,411	15,486	274,671	198,878	9,338	-	-
185	Subtotal - Other Power Generation Operation Expenses		6,546,196	2,979,482	10,069	110,516	1,960,191	1,419,297	66,640	-	-
186	**Other Power Generation Maintenance Expenses**										
187	Maintenance Supervision and Engineering	551	1	0	0	0	0	0	0	-	-
188	Maintenance of Structures	552	15,000	6,827	23	253	4,492	3,252	153	-	-
189	Maintenance of Generating and Electric Plant	553	8,602,756	3,915,519	13,232	145,236	2,576,007	1,865,185	87,576	-	-
190	Subtotal - Other Power Generation Maintenance Expenses		8,617,756	3,922,347	13,255	145,490	2,580,499	1,868,438	87,728	-	-
191	**Other Power Supply Expenses**										
192	System Control and Load Dispatching	556	670,659	305,248	1,032	11,322	200,822	145,407	6,827	-	-
193	All Other Expenses - Fixed	557	-	-	-	-	-	-	-	-	-
194	All Other Expenses - Variable	557	-	-	-	-	-	-	-	-	-
195	Subtotal - Other Power Supply Expenses		670,659	305,248	1,032	11,322	200,822	145,407	6,827	-	-

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196	**Transmission Operation Expenses**										
197	Operation Supervision and Engineering	560	419,171	190,784	645	7,077	125,516	90,881	4,267	-	-
198	Load Dispatching	561	19,910,336	9,062,132	30,625	336,137	5,961,946	4,316,810	202,686	-	-
199	Station Expenses	562	111,914	50,937	172	1,889	33,512	24,264	1,139	-	-
200	Overhead Line Expenses	563	(118)	(54)	(0)	(2)	(35)	(26)	(1)	-	-
201	Underground Line Expenses	564	-	-	-	-	-	-	-	-	-
202	Transmission of Electricity by Others	565	-	-	-	-	-	-	-	-	-
203	Miscellaneous Transmission Expenses	566	-	-	-	-	-	-	-	-	-
204	Rents	567	-	-	-	-	-	-	-	-	-
205	Subtotal - Transmission Operation Expenses		20,441,303	9,303,800	31,442	345,101	6,120,938	4,431,931	208,091	-	-
206	**Transmission Maintenance Expenses**										
207	Maintenance Supervision and Engineering	568	388,095	176,640	597	6,552	116,211	84,144	3,951	-	-
208	Maintenance of Structures	569	2,371,329	1,079,304	3,647	40,034	710,070	514,134	24,140	-	-
209	Maintenance of Station Equipment	570	233,432	106,246	359	3,941	69,899	50,611	2,376	-	-
210	Maintenance of Overhead Lines	571	579,737	263,866	892	9,787	173,596	125,694	5,902	-	-
211	Maintenance of Underground Lines	572	-	-	-	-	-	-	-	-	-
212	Maintenance of Miscellaneous Transmission Plant	573	-	-	-	-	-	-	-	-	-
213	Subtotal - Transmission Maintenance Expenses		3,572,594	1,626,056	5,495	60,314	1,069,776	774,583	36,369	-	-
214	**Distribution Operation Expenses**										
215	Operation Supervision and Engineering	580	1,941,263	1,445,917	31,150	104,467	251,537	102,206	5,474	198	315
216	Load Dispatching	581	256,022	113,552	489	4,399	72,599	61,352	3,319	120	191
217	Station Expenses	582	64,922	28,795	124	1,116	18,410	15,558	842	31	48
218	Overhead Line Expenses	583	-	-	-	-	-	-	-	-	-
219	Underground Line Expenses	584	-	-	-	-	-	-	-	-	-
220	Street Lighting and Signal System Expenses	585	-	-	-	-	-	-	-	-	-
221	Meter Expenses	586	1,157,573	958,903	23,112	74,049	100,568	933	9	-	-
222	Customer Installations Expenses	587	-	-	-	-	-	-	-	-	-
223	Miscellaneous Distribution Expenses	588	7,696,359	5,732,504	123,499	414,170	997,246	405,206	21,703	786	1,247
224	Rents	589	-	-	-	-	-	-	-	-	-
225	Subtotal - Distribution Operation Expenses		11,116,139	8,279,669	178,374	598,200	1,440,359	585,254	31,346	1,135	1,801
226	**Distribution Maintenance Expenses**										
227	Maintenance Supervision and Engineering	590	203,910	100,991	432	3,632	58,962	36,297	466	376	2,755
228	Maintenance of Structures	591	1,112,625	493,475	2,126	19,119	315,503	266,624	14,423	523	831
229	Maintenance of Station Equipment	592	815,274	361,593	1,558	14,009	231,185	195,369	10,569	383	609
230	Maintenance of Overhead Lines	593	8,631,137	4,420,389	18,881	156,668	2,534,496	1,452,425	-	18,660	29,619
231	Maintenance of Underground Lines	594	267,725	144,084	615	5,107	82,954	33,392	-	608	965
232	Maintenance of Line Transformers	595	-	-	-	-	-	-	-	-	-
233	Maintenance of Street Lighting and Signal Systems	596	115,832	-	-	-	-	-	-	-	115,832
234	Maintenance of Meters	597	-	-	-	-	-	-	-	-	-
235	Maintenance of Miscellaneous Distribution Plant	598	670,972	332,312	1,421	11,951	194,017	119,435	1,532	1,237	9,066
236	Subtotal - Distribution Maintenance Expenses		11,817,475	5,852,843	25,034	210,485	3,417,117	2,103,541	26,990	21,788	159,677
237	**Total Generation Production, Transmission, and Distribution Ex**		47,618,170	25,367,617	241,377	1,225,424	12,249,012	8,040,715	309,623	22,923	161,478

Cause No. 45990

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
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Schedule 3 - Cost of Service Allocation Study Detail by Account

Line No.	Account Description	FERC Account	Account Balance	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
238	**Customer Accounts, Service, and Sales Expense**										
239	**Customer Account**										
240	Supervision	901	-	-	-	-	-	-	-	-	-
241	Meter Reading Expenses	902	152,498	-	-	-	-	151,073	1,425	-	-
242	Customer Billing and Accounting	903	1,155,579	988,399	23,822	73,491	68,934	784	7	-	141
243	Uncollectible Accounts	904	2,279,803	2,215,142	9,222	28,448	26,684	304	3	-	-
244	Misc. Customer Accounts Expenses	905	70,218	60,060	1,448	4,466	4,189	48	0	-	9
245	Subtotal - Customer Account		3,658,099	3,263,601	34,492	106,405	99,807	152,209	1,436	-	149
				60,060	1,448	4,466	4,189	48	0	-	9
246	**Customer Service & Information Expenses**			3,263,601	34,492	106,405	99,807	152,209	1,436	-	149
247	Supervision	907	-	-	-	-	-	-	-	-	-
248	Customer Assistance	908	14,596	12,484	301	928	871	10	0	-	2
249	Informational and Instructional Advertising	909	-	-	-	-	-	-	-	-	-
250	Miscellaneous Customer Service and Informational	910	329	281	7	21	20	0	0	-	0
251	Subtotal - Customer Service & Information Expenses		14,925	12,766	308	949	890	10	0	-	2
				281	7	21	20	0	0	-	0
252	**Sales Expenses**			12,766	308	949	890	10	0	-	2
253	Supervision	911	1,139,859	974,953	23,498	72,492	67,997	774	7	-	139
254	Demonstrating and Selling Expenses	912	25,289	21,630	521	1,608	1,509	17	0	-	3
255	Advertising Expenses	913	-	-	-	-	-	-	-	-	-
256	Miscellaneous Sales Expenses	916	-	-	-	-	-	-	-	-	-
257	Subtotal - Sales Expenses		1,165,148	996,583	24,020	74,100	69,505	791	7	-	142
				-	-	-	-	-	-	-	-
258	**Total Customer Accounts, Service, and Sales Expense**		4,838,172	4,272,949	58,819	181,454	170,203	153,010	1,443	-	293
259	**Administrative and General Expenses**										
260	Administrative and General Salaries	920	20,391,648	10,839,276	109,889	541,563	5,141,606	3,525,490	156,829	3,364	73,630
261	Office Supplies and Expenses	921	2,742,248	1,457,655	14,778	72,829	691,438	474,104	21,090	452	9,902
262	Administrative Expenses Transferred - Company	922	-	-	-	-	-	-	-	-	-
263	Outside Services Employed	923	340,000	180,729	1,832	9,030	85,729	58,782	2,615	56	1,228
264	Property Insurance	924	2,276,531	1,120,369	6,635	48,375	641,283	425,218	14,673	4,928	15,050
265	Injuries and Damages	925	4,009,520	2,131,279	21,607	106,485	1,010,971	693,202	30,837	662	14,478
266	Employee Pensions and Benefits	926	8,123,484	4,318,076	43,777	215,744	2,048,278	1,404,460	62,477	1,340	29,332
267	Regulatory Commission Expenses	928	414,956	202,062	1,072	8,229	118,732	79,611	2,751	734	1,763
268	General Advertising Expenses	930.1	(835)	(406)	(2)	(17)	(239)	(160)	(6)	(1)	(4)
269	Miscellaneous General Expense	930.2	5,306,182	2,611,377	15,465	112,753	1,494,714	991,107	34,199	11,486	35,080
270	Rents	931	4,626,382	2,459,175	24,931	122,868	1,166,509	799,850	35,581	763	16,705
271	Maintenance of General Plant	935	1,156,447	612,948	6,143	30,489	292,683	200,952	8,952	187	4,092
272	Total Administrative and General Expenses		49,386,564	25,932,540	246,128	1,268,349	12,691,704	8,652,617	369,997	23,972	201,257
273	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		393,708,355	165,807,136	1,084,082	7,411,264	108,997,131	103,066,324	5,688,227	527,810	1,126,381

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274	**Adjustments, Depreciation and Amortization Expense**										
275	**Depreciation Expense**										
276	**Intangible Plant**			1,598,607	5,402	59,296	1,051,718	761,508	35,755	-	-
277	Organization	301	-	685,825	2,318	25,439	451,202	326,698	15,339	-	-
278	Franchises and Consents	302	-	-	-	-	-	-	-	-	-
279	Miscellaneous Intangible Plant	303	18,385,082	9,772,676	99,076	488,273	4,635,665	3,178,577	141,397	3,033	66,385
280	Subtotal - Intangible Plant		18,385,082	9,772,676	99,076	488,273	4,635,665	3,178,577	141,397	3,033	66,385
				-	-	-	-	-	-	-	-
281	**Other Production Plant**			-	-	-	-	-	-	-	-
282	Land and Land Rights	310	-	-	-	-	-	-	-	-	-
283	Structures and Improvements	311	5,712,146	2,599,867	8,786	96,436	1,710,443	1,238,465	58,149	-	-
284	Boiler Plant Equipment	312	21,729,351	9,890,051	33,423	366,847	6,506,631	4,711,196	221,203	-	-
285	Engines and Engine Driven Generators	313	-	-	-	-	-	-	-	-	-
286	Turbogenerator Units	314	998,400	454,419	1,536	16,856	298,961	216,466	10,164	-	-
287	Accessory Electric Equipment	315	1,970,549	896,890	3,031	33,268	590,061	427,240	20,060	-	-
288	Miscellaneous Power Plant Equipment	316	1,231,001	560,287	1,893	20,782	368,611	266,897	12,532	-	-
289	Asset Retirement Costs for Steam Production	317	-	-	-	-	-	-	-	-	-
290	Subtotal - Other Production Plant		31,641,447	14,401,513	48,669	534,188	9,474,706	6,860,262	322,108	-	-
				-	-	-	-	-	-	-	-
291	**Other Production Plant**			-	-	-	-	-	-	-	-
292	Land and Land Rights	340	-	-	-	-	-	-	-	-	-
293	Structures and Improvements	341	76,322	34,738	117	1,289	22,854	16,548	777	-	-
294	Fuel Holders, Producers and Accessories	342	70,847	32,246	109	1,196	21,214	15,360	721	-	-
295	Prime Movers	343	842,977	383,678	1,297	14,232	252,421	182,768	8,581	-	-
296	Generators	344	553,653	251,994	852	9,347	165,786	120,039	5,636	-	-
297	Accessory Electric Equipment	345	137,601	62,629	212	2,323	41,203	29,834	1,401	-	-
298	Miscellaneous Power Plant Equipment	346	24,331,594	11,074,455	37,426	410,779	7,285,846	5,275,394	247,694	-	-
299	Asset Retirement Costs for Other Production	347	-	-	-	-	-	-	-	-	-
300	Subtotal - Other Production Plant		26,012,993	11,839,739	40,012	439,166	7,789,324	5,639,943	264,811	-	-
				-	-	-	-	-	-	-	-
301	**Other Production Plant**			-	-	-	-	-	-	-	-
302	Land and Land Rights	350	143,300	65,223	220	2,419	42,910	31,069	1,459	-	-
303	Structures and Improvements	352	91,477	41,636	141	1,544	27,392	19,833	931	-	-
304	Station Equipment	353	3,139,593	1,428,977	4,829	53,004	940,119	680,703	31,961	-	-
305	Towers and Fixtures	354	17,043	7,757	26	288	5,103	3,695	173	-	-
306	Poles and Fixtures	355	5,951,193	2,708,668	9,154	100,471	1,782,024	1,290,293	60,583	-	-
307	Overhead Conductors and Devices	356	2,833,897	1,289,840	4,359	47,843	848,581	614,424	28,849	-	-
308	Underground Conduit	357	14,054	6,396	22	237	4,208	3,047	143	-	-
309	Underground Conductors and Devices	358	9,361	4,261	14	158	2,803	2,030	95	-	-
310	Road and Trails	359	-	-	-	-	-	-	-	-	-
311	ARO for Transmission Plant	359.1	-	-	-	-	-	-	-	-	-
312	Subtotal - Other Production Plant		12,199,918	5,552,757	18,765	205,966	3,653,140	2,645,095	124,194	-	-

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					-	-	-	-	-	-	-
313	**Distribution Plant**			-	-	-	-	-	-	-	-
314	Land and land rights	360	1,177	593	3	21	340	213	-	3	4
315	Structures and improvements	361	19,706	9,994	43	354	5,725	3,480	-	42	67
316	Station equipment	362	4,013,204	1,984,104	8,475	70,321	1,134,127	794,507	-	8,376	13,294
317	Storage battery equipment	363	-	-	-	-	-	-	-	-	-
318	Poles, Towers and Fixtures	364	15,005,586	7,699,180	32,886	272,875	4,415,133	2,501,423	-	32,501	51,588
319	Overhead Conductors and Devices	365	13,295,258	6,809,093	29,084	241,328	3,904,095	2,237,291	-	28,743	45,624
320	Underground conduit	366	1,015,632	546,591	2,335	19,372	314,691	126,673	-	2,307	3,662
321	Underground Conductors and Devices	367	2,912,001	1,567,176	6,694	55,544	902,276	363,194	-	6,616	10,501
322	Transformers and Transformer Installations	368	1,749,229	1,219,616	21,856	75,889	275,473	152,244	-	1,605	2,547
323	Services	369	1,993,032	1,521,735	36,677	201,909	230,600	2,091	20	-	-
324	Meters	370	1,852,884	1,534,879	36,994	118,528	160,975	1,493	14	-	-
325	Installations on customers premises	371	192,489	-	-	-	-	-	-	192,489	-
326	Street lighting and signal systems	373	431,653	-	-	-	-	-	-	-	431,653
327	Subtotal - Distribution Plant		42,481,852	22,892,963	175,045	1,056,142	11,343,436	6,182,610	34	272,681	558,942
				-	-	-	-	-	-	-	-
328	**General Plant**			-	-	-	-	-	-	-	-
329	Land and Land Rights	389	-	-	-	-	-	-	-	-	-
330	Structures and Improvements	390	1,139,965	605,954	6,143	30,275	287,434	197,087	8,767	188	4,116
331	Office Furniture and Equipment	391	1,445,296	768,254	7,789	38,384	364,421	249,876	11,116	238	5,219
332	Transportation Equipment	392	1,805,524	959,735	9,730	47,951	455,250	312,155	13,886	298	6,519
333	Stores Equipment	393	22,940	12,194	124	609	5,784	3,966	176	4	83
334	Tools, Shop and Garage Equipment	394	369,878	196,610	1,993	9,823	93,262	63,948	2,845	61	1,336
335	Laboratory Equipment	395	92,074	48,943	496	2,445	23,216	15,919	708	15	332
336	Power Operated Equipment	396	245,204	130,340	1,321	6,512	61,827	42,393	1,886	40	885
337	Communication Equipment	397	1,505,059	800,021	8,111	39,972	379,490	260,208	11,575	248	5,434
338	Miscellaneous Equipment	398	127,525	67,787	687	3,387	32,155	22,048	981	21	460
339	Miscellaneous Equipment-DLC	398	154,194	70,181	237	2,603	46,172	33,431	1,570	-	-
340	Subtotal - General Plant		6,907,660	3,660,018	36,631	181,962	1,749,009	1,201,031	53,510	1,114	24,385
				-	-	-	-	-	-	-	-
341	**Amortization Expense**			-	-	-	-	-	-	-	-
342	Regulatory Amortization - TDISC	407.4	7,935,299	4,151,652	30,680	196,655	2,134,175	1,253,145	17,891	38,499	112,601
343	Regulatory Amortization - CECA	407.4	167,953	76,443	258	2,835	50,292	36,414	1,710	-	-
344	Regulatory Amortization - ECA	407.4	24,657,372	11,222,732	37,927	416,279	7,383,397	5,346,027	251,010	-	-
345	Regulatory Amortization - AMI	407.4	1,643,527	1,405,754	33,882	104,523	98,042	1,116	11	-	200
346	Regulatory Amortization - CT	407.4	118,495	53,933	182	2,001	35,482	25,691	1,206	-	-
347	Pro Forma Amortization Expense - Deferred Medicare Tax Liat	407.4	(347,401)	(184,663)	(1,872)	(9,226)	(87,595)	(60,062)	(2,672)	(57)	(1,254)
348	Subtotal - Amortization Expense		34,175,245	16,725,851	101,057	713,067	9,613,793	6,602,331	269,156	38,442	111,547
349	**Total Adjustments, Depreciation and Amortization Expense**		171,804,198	84,845,518	519,255	3,618,764	48,259,073	32,309,849	1,175,209	315,271	761,259

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350	**Taxes**										
351	**Taxes Other Than Income Taxes**										
352	Taxes Other Than Income Taxes - Property	408.1	9,516,863	4,683,616	27,738	202,227	2,680,834	1,777,592	61,338	20,601	62,917
353	Taxes Other Than Income Taxes - Payroll	408.1	2,783,210	1,479,429	14,999	73,917	701,766	481,186	21,405	459	10,050
354	Taxes Other Than Income Taxes - Other	408.02	-	-	-	-	-	-	-	-	-
355	Taxes Other Than Income Taxes - Other	408.02	-	-	-	-	-	-	-	-	-
356	Investment Tax Credits		-	-	-	-	-	-	-	-	-
357	Subtotal - Taxes Other Than Income Taxes		12,300,073	6,163,044	42,736	276,144	3,382,600	2,258,779	82,743	21,060	72,967
358	**Income Taxes**										
359	State Income Tax	409.01	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)
360	Federal Income Tax	409	11,324,453	5,514,420	29,266	224,584	3,240,297	2,172,646	75,080	20,044	48,117
361	Deferred Federal & State Income Taxes	410	3,589,036	1,766,303	10,461	76,265	1,011,006	670,373	23,132	7,769	23,728
362	Subtotal - Income Taxes		14,913,489	7,280,723	39,726	300,849	4,251,303	2,843,018	98,212	27,813	71,844
363	**Total Taxes**		27,213,562	13,443,767	82,462	576,994	7,633,903	5,101,797	180,956	48,872	144,811
364	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**										
365	**Test Year Expenses at Current Rates**		592,726,115	264,096,421	1,685,800	11,607,022	164,890,107	140,477,970	7,044,392	891,953	2,032,451
366	**Return on Rate Base**		187,518,958	91,311,982	484,601	3,718,842	53,655,311	35,976,333	1,243,239	331,898	796,752
367	**Gross Up Items**			-	-	-	-	-	-	-	-
368	Gross-up State Income Tax		4,584,096	2,232,216	11,847	90,911	1,311,660	879,479	30,392	8,114	19,477
369	Gross-up Federal Income Tax		18,683,465	9,097,876	48,283	370,527	5,345,951	3,584,504	123,870	33,069	79,384
370	Gross-up IURC Assessment		137,915	67,157	356	2,735	39,462	26,460	914	244	586
371	Gross-up Bad Debts		281,918	137,280	729	5,591	80,666	54,087	1,869	499	1,198
372	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		803,932,466	366,942,931	2,231,616	15,795,627	225,323,157	180,998,832	8,444,677	1,265,777	2,929,848

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373	**INTERNAL ALLOCATION FACTORS**										
374	INT_STEAM_PROD_PT		774,486,722	352,505,393	1,191,275	13,075,311	231,912,090	167,918,427	7,884,226	0	0
375	INT_OTHER_PROD_PT		855,100,022	389,196,303	1,315,270	14,436,270	256,050,915	185,396,401	8,704,865	0	0
376	INT_TRANSMISSION_PT		574,404,982	261,438,767	883,519	9,697,421	171,999,669	124,538,198	5,847,407	0	0
377	INT_DIST_PLANT		1,346,647,831	730,605,185	6,098,051	36,398,072	350,500,249	190,111,038	1,222	8,391,350	24,542,663
378	INT_TOTAL_PLANT		3,903,197,879	1,920,914,445	11,376,172	82,940,564	1,099,503,552	729,052,713	25,156,856	8,449,008	25,804,568
379	INT_RATEBASE		2,769,851,666	1,348,773,734	7,158,066	54,931,192	792,545,219	531,408,163	18,363,947	4,902,484	11,768,861
380	INT_TRANS_OPS		20,022,132	9,113,015	30,797	338,025	5,995,422	4,341,049	203,824	0	0
381	INT_TRANS_MAINT		3,184,499	1,449,416	4,898	53,762	953,566	690,439	32,418	0	0
382	INT_DIST_OPS		1,478,517	1,101,249	23,725	79,564	191,577	77,842	4,169	151	240
383	INT_DIST_MAINT		10,942,593	5,419,540	23,181	194,903	3,164,137	1,947,810	24,992	20,175	147,855
384	INT_361-364		559,325,756	282,114,921	1,205,013	9,998,733	161,542,246	101,383,645	0	1,190,898	1,890,300
385	INT_364		297,854,492	152,825,448	652,772	5,416,448	87,638,508	49,652,190	0	645,125	1,024,001
386	INT_365		312,095,266	159,837,858	682,724	5,664,982	91,645,421	52,518,566	0	674,727	1,070,988
387	INT_367		165,164,611	88,888,042	379,672	3,150,375	51,175,844	20,599,861	0	375,225	595,591
388	INT_368		103,114,848	71,894,808	1,288,367	4,473,573	16,238,754	8,974,567	0	94,608	150,171
389	INT_STNS,POLES,LINES		869,881,492	441,171,985	1,884,402	15,636,042	252,740,364	153,630,314	0	1,862,328	2,956,056
390	INT_T&D_OH_CNDT		418,889,136	208,444,779	846,989	7,467,935	123,623,748	75,672,815	1,087,155	674,727	1,070,988
391	INT_LABOR		25,452,949	13,529,634	137,164	675,982	6,417,776	4,400,533	195,755	4,199	91,906
392	INT_REVREQ		803,932,466	366,942,931	2,231,616	15,795,627	225,323,157	180,998,832	8,444,677	1,265,777	2,929,848
393	INT_GENPT		153,998,437	81,623,362	818,032	4,060,118	38,975,196	26,759,846	1,192,042	24,899	544,943
394	INT_TOTAL_PLANT_EXCL INT		3,704,637,994	1,815,369,009	10,306,146	77,667,192	1,049,438,120	694,723,910	23,629,762	8,416,249	25,087,606
395	INT_DIST (60%)_TRANSM (40%)_PLANT		1,037,750,691	542,938,618	4,012,238	25,717,812	279,100,017	163,881,902	2,339,696	5,034,810	14,725,598
397	Operating Revenue										
398	Base Rate Revenue		267,328,652	132,139,577	530,561	5,953,227	75,824,903	48,031,238	1,868,205	1,152,148	1,828,794
399	Fuel Cost Revenue		207,300,587	75,970,833	391,108	3,344,186	59,219,378	63,597,486	3,765,866	391,039	620,692
400	Special Contract Revenue		30,156,859	13,764,647	83,712	592,521	8,452,251	6,789,571	316,774	47,481	109,904
401	Non-Firm Revenue		14,611,626	6,669,258	40,560	287,089	4,095,291	3,289,688	153,484	23,006	53,251
402	Forfeited Discounts		2,551,683	1,142,913	6,208	53,353	735,598	566,346	29,022	6,886	11,357
403	Reconnect Charge		237,837	226,325	1,642	5,065	4,751	54	1	-	-
404	Returned Check Charge		104,726	99,263	779	2,403	2,254	26	0	-	-
405	Securitization Fees		245,725	112,157	682	4,828	68,871	55,323	2,581	387	896
406	Interdepartmental Sales		100,367	45,811	279	1,972	28,130	22,597	1,054	158	366
407	Rent From Property		5,062,099	2,310,519	14,052	99,460	1,418,786	1,139,690	53,173	7,970	18,448
408	LRAM Incentive		-	-	-	-	-	-	-	-	-
409	Rider Revenue		99,379,048	49,842,143	487,680	2,724,122	29,673,721	15,662,293	814,423	29,159	145,507
410	Rider Revenue_Special Contract		12,267,532	5,599,331	34,053	241,032	3,438,298	2,761,935	128,861	19,315	44,708
411	Variable Production Revenue_Special Contract		4,870,592	1,767,260	9,296	78,617	1,390,814	1,510,021	89,455	9,713	15,417
412	Variable Production Revenue		18,054,808	6,551,059	34,459	291,427	5,155,612	5,597,499	331,601	36,004	57,149
413	Transmission Revenue		8,758,794	3,997,820	24,313	172,092	2,454,882	1,971,971	92,004	13,791	31,921
414	Fuel Cost Revenue_Special Contract		52,891,914	19,383,654	99,790	853,256	15,109,587	16,226,644	960,846	99,772	158,367
415	Total Operating Revenue		723,922,849	319,622,569	1,759,173	14,704,649	207,073,126	167,222,380	8,607,350	1836827.708	3096774.211
416	NET INCOME AT CURRENT RATES		131,196,735	55,526,149	73,374	3,097,628	42,183,019	26,744,410	1,562,958	944,875	1,064,323

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
1	**RATE BASE**								
2	**Plant in Service**								
3	**Intangible Plant**								
4	Organization	301.0	12,151	INT_LABOR					
5	Franchises and Consents	302.0	0						
6	Miscellaneous Intangible Plant	303.0	198,547,734	INT_LABOR					
7	Subtotal - Intangible Plant		198,559,885						
8	**Steam Production Plant**								
9	Land and Land Rights	310.0	1,976,433		PRODUCTION	DEMAND	4CP_Demand		
10	Structures and Improvements	311.0	96,772,607		PRODUCTION	DEMAND	4CP_Demand		
11	Boiler Plant Equipment	312.0	569,693,573		PRODUCTION	DEMAND	4CP_Demand		
12	Engines and Engine Driven Generators	313.0	0		PRODUCTION	DEMAND	4CP_Demand		
13	Turbogenerator Units	314.0	48,177,832		PRODUCTION	DEMAND	4CP_Demand		
14	Accessory Electric Equipment	315.0	33,226,393		PRODUCTION	DEMAND	4CP_Demand		
15	Miscellaneous Power Plant Equipment	316.0	24,639,884		PRODUCTION	DEMAND	4CP_Demand		
16	Asset Retirement Costs for Steam Production	317.0	0		PRODUCTION	DEMAND	4CP_Demand		
17	Subtotal - Steam Production Plant		774,486,722						
18	**Other Production Plant**								
19	Land and Land Rights	340.0	389,504		PRODUCTION	DEMAND	4CP_Demand		
20	Structures and Improvements	341.0	2,271,907		PRODUCTION	DEMAND	4CP_Demand		
21	Fuel Holders, Producers and Accessories	342.0	4,101,467		PRODUCTION	DEMAND	4CP_Demand		
22	Prime Movers	343.0	48,262,971		PRODUCTION	DEMAND	4CP_Demand		
23	Generators	344.0	17,496,247		PRODUCTION	DEMAND	4CP_Demand		
24	Accessory Electric Equipment	345.0	5,263,501		PRODUCTION	DEMAND	4CP_Demand		
25	Miscellaneous Power Plant Equipment	346.0	777,314,426		PRODUCTION	DEMAND	4CP_Demand		
26	Asset Retirement Costs for Other Production	347.0	0		PRODUCTION	DEMAND	4CP_Demand		
27	Subtotal - Other Production Plant		855,100,022						
28	**Transmission Plant**								
29	Land and Land Rights	350.0	19,334,962		TRANSMISSION	DEMAND	4CP_Demand		
30	Structures and Improvements	352.0	6,442,051		TRANSMISSION	DEMAND	4CP_Demand		
31	Station Equipment	353.0	196,875,807		TRANSMISSION	DEMAND	4CP_Demand		
32	Towers and Fixtures	354.0	4,622,707		TRANSMISSION	DEMAND	4CP_Demand		
33	Poles and Fixtures	355.0	237,797,966		TRANSMISSION	DEMAND	4CP_Demand		
34	Overhead Conductors and Devices	356.0	106,793,870		TRANSMISSION	DEMAND	4CP_Demand		
35	Underground Conduit	357.0	1,180,974		TRANSMISSION	DEMAND	4CP_Demand		
36	Underground Conductors and Devices	358.0	1,356,646		TRANSMISSION	DEMAND	4CP_Demand		
37	Road and Trails	359.0	0		TRANSMISSION	DEMAND	4CP_Demand		
38	ARO for Transmission Plant	359.1	0		TRANSMISSION	DEMAND	4CP_Demand		
39	Subtotal - Transmission Plant		574,404,982						

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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
40	**Distribution Plant**								
41	Land and land rights	360.0	3,081,457	INT_361-364					
42	Structures and improvements	361.0	1,539,531	INT_STNS,POLES,LINES					
43	Station equipment	362.0	259,931,734		SUBSTATION	DEMAND	NCP_PRI		
44	Storage battery equipment	363.0	0						
45	Poles, Towers and Fixtures - PRI DEM	364.0	250,802,380		DIST PRIMARY	DEMAND	NCP_PRI		
46	Poles, Towers and Fixtures - PRI CUST	364.0	0		DIST PRIMARY	CUSTOMER			CUST_PRI
47	Poles, Towers and Fixtures - SEC DEM	364.0	47,052,112		DIST SECONDARY	DEMAND	NCP_SEC		
48	Poles, Towers and Fixtures - SEC CUST	364.0	0		DIST SECONDARY	CUSTOMER			CUST_SEC
49	Overhead Conductors and Devices - PRI DEM	365.0	265,280,976		DIST PRIMARY	DEMAND	NCP_PRI		
50	Overhead Conductors and Devices - PRI CUST	365.0	0		DIST PRIMARY	CUSTOMER			CUST_PRI
51	Overhead Conductors and Devices - SEC DEM	365.0	46,814,290		DIST SECONDARY	DEMAND	NCP_SEC		
52	Overhead Conductors and Devices - SEC CUST	365.0	0		DIST SECONDARY	CUSTOMER			CUST_SEC
53	Underground conduit	366.0	47,676,074	INT_367					
54	Underground Conductors and Devices - PRI DEM	367.0	104,053,705		DIST PRIMARY	DEMAND	NCP_PRI		
55	Underground Conductors and Devices - PRI CUST	367.0	0		DIST PRIMARY	CUSTOMER			CUST_PRI
56	Underground Conductors and Devices - SEC DEM	367.0	61,110,906		DIST SECONDARY	DEMAND	NCP_SEC		
57	Underground Conductors and Devices - SEC CUST	367.0	0		DIST SECONDARY	CUSTOMER			CUST_SEC
58	Transformers and Transformer Installations - DEM	368.0	45,332,193		TRANSFORMATION	DEMAND	NCP_PRI		
59	Transformers and Transformer Installations - CUST	368.0	57,782,655		TRANSFORMATION	CUSTOMER			CUST_SEC
60	Services	369.0	103,266,723		ONSITE & METERING	CUSTOMER			SERV
61	Meters	370.0	26,328,799		ONSITE & METERING	CUSTOMER			MTRS
62	Installations on customers premises	371.0	5,941,020		LIGHTING PLANT	CUSTOMER			OUTDOOR-LIGHT
63	Street lighting and signal systems	373.0	20,653,277		LIGHTING PLANT	CUSTOMER			STREET-LIGHT
64	Subtotal - Distribution Plant		1,346,647,831						
65	**General Plant**								
66	Land and Land Rights	389.0	2,309,376	INT_LABOR					
67	Structures and Improvements	390.0	56,222,863	INT_LABOR					
68	Office Furniture and Equipment	391.0	23,986,173	INT_LABOR					
69	Transportation Equipment	392.0	25,161,795	INT_LABOR					
70	Stores Equipment	393.0	688,773	INT_LABOR					
71	Tools, Shop and Garage Equipment	394.0	9,246,944	INT_LABOR					
72	Laboratory Equipment	395.0	1,859,238	INT_LABOR					
73	Power Operated Equipment	396.0	5,812,993	INT_LABOR					
74	Communication Equipment	397.0	22,869,808	INT_LABOR					
75	Miscellaneous Equipment	398.0	2,761,879	INT_LABOR					
76	Miscellaneous Equipment-DLC	398.0	3,078,597		PRODUCTION	DEMAND	4CP_Demand		
77	Subtotal - General Plant		153,998,437						
78	**Total Plant in Service**		3,903,197,879						

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Schedule 4 - Account Balances and Allocation Methods

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
79	**Accumulated Depreciation & Amortization**								
80	**Intangible Plant**								
81	Organization	301.0	0	INT_LABOR	-	-	-	-	-
82	Franchises and Consents	302.0	0	-	-	-	-	-	-
83	Miscellaneous Intangible Plant	303.0	(120,558,306)	INT_LABOR	-	-	-	-	-
84	Subtotal - Intangible Plant		(120,558,306)						
85	**Steam Production Plant**								
86	Land and Land Rights	310.0	142,880	-	PRODUCTION	DEMAND	4CP_Demand	-	-
87	Structures and Improvements	311.0	(46,698,062)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
88	Boiler Plant Equipment	312.0	(264,424,780)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
89	Engines and Engine Driven Generators	313.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
90	Turbogenerator Units	314.0	(36,101,462)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
91	Accessory Electric Equipment	315.0	(3,420,234)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
92	Miscellaneous Power Plant Equipment	316.0	(8,721,704)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
93	Asset Retirement Costs for Steam Production	317.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
94	Subtotal - Steam Production Plant		(359,223,363)						
95	**Other Production Plant**								
96	Land and Land Rights	340.0	38,004	-	PRODUCTION	DEMAND	4CP_Demand	-	-
97	Structures and Improvements	341.0	(2,231,173)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
98	Fuel Holders, Producers and Accessories	342.0	(4,631,843)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
99	Prime Movers	343.0	(42,171,802)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
100	Generators	344.0	(13,256,606)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
101	Accessory Electric Equipment	345.0	(4,116,286)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
102	Miscellaneous Power Plant Equipment	346.0	(16,512,384)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
103	Asset Retirement Costs for Other Production	347.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
104	Subtotal - Other Production Plant		(82,882,091)						
105	**Transmission Plant**								
106	Land and Land Rights	350.0	(4,213,024)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
107	Structures and Improvements	352.0	(2,543,412)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
108	Station Equipment	353.0	(55,183,260)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
109	Towers and Fixtures	354.0	(5,214,294)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
110	Poles and Fixtures	355.0	(55,473,356)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
111	Overhead Conductors and Devices	356.0	(27,944,809)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
112	Underground Conduit	357.0	(968,589)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
113	Underground Conductors and Devices	358.0	(1,294,260)	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
114	Road and Trails	359.0	0	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
115	ARO for Transmission Plant	359.1	0	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
116	Subtotal - Transmission Plant		(152,835,002)						

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
117	**Distribution Plant**								
118	Land and land rights	360.0	(20,815)	INT_361-364	-	-	-	-	-
119	Structures and improvements	361.0	(897,293)	INT_STNS,POLES,LINES	-	-	-	-	-
120	Station equipment	362.0	(44,601,013)	-	SUBSTATION	DEMAND	NCP_PRI	-	-
121	Storage battery equipment	363.0	0	-	-	-	-	-	-
122	Poles, Towers and Fixtures	364.0	(90,761,034)	INT_364					
123	Overhead Conductors and Devices	365.0	(91,322,510)	INT_365					
124	Underground conduit	366.0	(18,345,845)	INT_367	-	-	-	-	-
125	Underground Conductors and Devices	367.0	(51,477,871)	INT_367					
126	Transformers and Transformer Installations	368.0	(52,561,797)	INT_368					
127	Services	369.0	(71,529,816)	-	ONSITE & METERING	CUSTOMER	-	-	SERV
128	Meters	370.0	(2,976,324)	-	ONSITE & METERING	CUSTOMER	-	-	MTRS
129	Installations on customers premises	371.0	(2,944,632)	-	LIGHTING PLANT	CUSTOMER	-	-	OUTDOOR-LIGHT
130	Street lighting and signal systems	373.0	(12,598,490)	-	LIGHTING PLANT	CUSTOMER	-	-	STREET-LIGHT
131	Subtotal - Distribution Plant		(440,037,441)						
132	**General Plant**								
133	Land and Land Rights	389.0	(22,147)	INT_LABOR	-	-	-	-	-
134	Structures and Improvements	390.0	(17,518,991)	INT_LABOR	-	-	-	-	-
135	Office Furniture and Equipment	391.0	(15,258,932)	INT_LABOR	-	-	-	-	-
136	Transportation Equipment	392.0	(16,726,737)	INT_LABOR	-	-	-	-	-
137	Stores Equipment	393.0	(574,962)	INT_LABOR	-	-	-	-	-
138	Tools, Shop and Garage Equipment	394.0	(2,180,271)	INT_LABOR	-	-	-	-	-
139	Laboratory Equipment	395.0	(1,935,880)	INT_LABOR	-	-	-	-	-
140	Power Operated Equipment	396.0	(2,361,451)	INT_LABOR	-	-	-	-	-
141	Communication Equipment	397.0	(9,472,725)	INT_LABOR	-	-	-	-	-
142	Miscellaneous Equipment	398.0	(480,682)	INT_LABOR	-	-	-	-	-
143	Miscellaneous Equipment-DLC	398.0	(5,512,812)	-	PRODUCTION	DEMAND	4CP_Demand	-	-
144	Subtotal - General Plant		(72,045,589)						
145	**Total Accumulated Depreciation & Amortization**		(1,227,581,792)						
146	**Other Rate Base Items**								
147	Fuel Stock & Expense	151.0	8,990,701		PRODUCTION	ENERGY		ENERGY	
148	Materials and Supplies (Generation Inventory)	154.0	41,360,961		PRODUCTION	DEMAND	4CP_Demand		
149	Allowance Inventory	158.0	0		PRODUCTION	DEMAND	4CP_Demand		
150	Stores Expense	163.0	311,332	INT_TOTAL_PLANT					
151	PISCC - AMI	182.3	10,585,830		CUST ACCTS & SRVC	CUSTOMER			CUST
152	PISCC - ECA	182.3	5,575,984		PRODUCTION	DEMAND	4CP_Demand		
153	PISCC - CECA	182.3	2,963,459		PRODUCTION	DEMAND	4CP_Demand		
154	PISCC - TDSIC	182.3	21,951,124	ST (60%)_TRANSM (40%)_PLANT					
155	PISCC - CT	182.3	2,496,186		PRODUCTION	DEMAND	4CP_Demand		
156	**Total Other Rate Base Items**		94,235,578						
157	**TOTAL RATE BASE**		2,769,851,666						

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158	**OPERATION AND MAINTENANCE EXPENSE**								
159	**Generation Production, Transmission, and Distribution Expense**								
160	**Steam Power Generation Operation Expenses**								
161	Operation Supervision and Engineering	500.0	743,496		PRODUCTION	DEMAND	4CP_Demand		
162	Fuel	501.0	246,229,310		FUEL EXPENSES	ENERGY		REV_ENERGY	
163	Fuel (Operation Related Expenses)	501.0	2,240,456		PRODUCTION	DEMAND	4CP_Demand		
164	Steam Expenses	502.0	1,969,108		PRODUCTION	DEMAND	4CP_Demand		
165	Steam Expenses - VPC	502.0	7,310,722		VPC	ENERGY		REV_PROPOSED_VP	
166	Electric Expenses	505.0	1,348,774		PRODUCTION	DEMAND	4CP_Demand		
167	Electric Expenses - VPC	505.0	165,000		VPC	ENERGY		REV_PROPOSED_VP	
168	Miscellaneous Steam Power Expenses	506.0	2,163,147		PRODUCTION	DEMAND	4CP_Demand		
169	Miscellaneous Steam Power Expenses - VPC	506.0	299,500		VPC	ENERGY		REV_PROPOSED_VP	
170	Rents	507.0	0		PRODUCTION	DEMAND	4CP_Demand		
171	Allowances	509.0	0		PRODUCTION	DEMAND	4CP_Demand		
172	Subtotal - Steam Power Generation Operation Expenses		262,469,512						
173	**Steam Power Generation Maintenance Expenses**								
174	Maintenance Supervision and Engineering	510.0	492,730		PRODUCTION	DEMAND	4CP_Demand		
175	Maintenance of Structures	511.0	1,494,465		PRODUCTION	DEMAND	4CP_Demand		
176	Maintenance of Boiler Plant	512.0	6,725,481		PRODUCTION	DEMAND	4CP_Demand		
177	Maintenance of Boiler Plant-VPC	512.0	500,200		VPC	ENERGY		REV_PROPOSED_VP	
178	Maintenance of Electric Plant	513.0	3,512,286		PRODUCTION	DEMAND	4CP_Demand		
179	Maintenance of Miscellaneous Steam Plant	514.0	1,506,822		PRODUCTION	DEMAND	4CP_Demand		
180	Subtotal - Steam Power Generation Maintenance Expenses		14,231,984						
181	**Other Power Generation Operation Expenses**								
182	Operations Supervision and Engineering	546.0	20,563		PRODUCTION	DEMAND	4CP_Demand		
183	Generation Expenses	548.0	5,608,351		PRODUCTION	DEMAND	4CP_Demand		
184	Miscellaneous Other Power Generation Expenses	549.0	917,282		PRODUCTION	DEMAND	4CP_Demand		
185	Subtotal - Other Power Generation Operation Expenses		6,546,196						
186	**Other Power Generation Maintenance Expenses**								
187	Maintenance Supervision and Engineering	551.0	1		PRODUCTION	DEMAND	4CP_Demand		
188	Maintenance of Structures	552.0	15,000		PRODUCTION	DEMAND	4CP_Demand		
189	Maintenance of Generating and Electric Plant	553.0	8,602,756		PRODUCTION	DEMAND	4CP_Demand		
190	Subtotal - Other Power Generation Maintenance Expenses		8,617,756						
191	**Other Power Supply Expenses**								
192	System Control and Load Dispatching	556.0	670,659		PRODUCTION	DEMAND	4CP_Demand		
193	All Other Expenses - Fixed	557.0	0						
194	All Other Expenses - Variable	557.0	0						
195	Subtotal - Other Power Supply Expenses		670,659						

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196	**Transmission Operation Expenses**								
197	Operation Supervision and Engineering	560.0	419,171		TRANSMISSION	DEMAND	4CP_Demand		
198	Load Dispatching	561.0	19,910,336		TRANSMISSION	DEMAND	4CP_Demand		
199	Station Expenses	562.0	111,914		TRANSMISSION	DEMAND	4CP_Demand		
200	Overhead Line Expenses	563.0	(118)		TRANSMISSION	DEMAND	4CP_Demand		
201	Underground Line Expenses	564.0	0						
202	Transmission of Electricity by Others	565.0	0						
203	Miscellaneous Transmission Expenses	566.0	0						
204	Rents	567.0	0						
205	Subtotal - Transmission Operation Expenses		20,441,303						
206	**Transmission Maintenance Expenses**								
207	Maintenance Supervision and Engineering	568.0	388,095		TRANSMISSION	DEMAND	4CP_Demand		
208	Maintenance of Structures	569.0	2,371,329		TRANSMISSION	DEMAND	4CP_Demand		
209	Maintenance of Station Equipment	570.0	233,432		TRANSMISSION	DEMAND	4CP_Demand		
210	Maintenance of Overhead Lines	571.0	579,737		TRANSMISSION	DEMAND	4CP_Demand		
211	Maintenance of Underground Lines	572.0	0						
212	Maintenance of Miscellaneous Transmission Plant	573.0	0						
213	Subtotal - Transmission Maintenance Expenses		3,572,594						
214	**Distribution Operation Expenses**								
215	Operation Supervision and Engineering	580.0	1,941,263	INT_DIST_OPS					
216	Load Dispatching	581.0	256,022		DIST PRIMARY	DEMAND	12CP_Demand		
217	Station Expenses	582.0	64,922		SUBSTATION	DEMAND	12CP_Demand		
218	Overhead Line Expenses	583.0	0	INT_365					
219	Underground Line Expenses	584.0	0	INT_367					
220	Street Lighting and Signal System Expenses	585.0	0		LIGHTING PLANT	CUSTOMER			STREET-LIGHT
221	Meter Expenses	586.0	1,157,573		ONSITE & METERING	CUSTOMER			MTRS
222	Customer Installations Expenses	587.0	0		ONSITE & METERING	CUSTOMER			MTRS
223	Miscellaneous Distribution Expenses	588.0	7,696,359	INT_DIST_OPS					
224	Rents	589.0	0	INT_DIST_OPS					
225	Subtotal - Distribution Operation Expenses		11,116,139						
226	**Distribution Maintenance Expenses**								
227	Maintenance Supervision and Engineering	590.0	203,910	INT_DIST_MAINT					
228	Maintenance of Structures	591.0	1,112,625		DIST PRIMARY	DEMAND	12CP_Demand		
229	Maintenance of Station Equipment	592.0	815,274		DIST PRIMARY	DEMAND	12CP_Demand		
230	Maintenance of Overhead Lines	593.0	8,631,137	INT_365					
231	Maintenance of Underground Lines	594.0	267,725	INT_367					
232	Maintenance of Line Transformers	595.0	0						
233	Maintenance of Street Lighting and Signal Systems	596.0	115,832		LIGHTING PLANT	CUSTOMER			STREET-LIGHT
234	Maintenance of Meters	597.0	0		ONSITE & METERING	CUSTOMER			MTRS
235	Maintenance of Miscellaneous Distribution Plant	598.0	670,972	INT_DIST_MAINT					
236	Subtotal - Distribution Maintenance Expenses		11,817,475						
237	**Total Generation Production, Transmission, and Distribution Expense**		47,618,170						

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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
238	**Customer Accounts, Service, and Sales Expense**								
239	**Customer Account**								
240	Supervision	901.0	0						
241	Meter Reading Expenses	902.0	152,498		CUST ACCTS & SRVC	CUSTOMER			MTR_READ
242	Customer Billing and Accounting	903.0	1,155,579		CUST ACCTS & SRVC	CUSTOMER			CUST
243	Uncollectible Accounts	904.0	2,279,803		CUST ACCTS & SRVC	CUSTOMER			UNCOLL
244	Misc. Customer Accounts Expenses	905.0	70,218		CUST ACCTS & SRVC	CUSTOMER			CUST
245	Subtotal - Customer Account		3,658,099						
246	**Customer Service & Information Expenses**								
247	Supervision	907.0	0						
248	Customer Assistance	908.0	14,596		CUST ACCTS & SRVC	CUSTOMER			CUST
249	Informational and Instructional Advertising	909.0	0						
250	Miscellaneous Customer Service and Informational	910.0	329		CUST ACCTS & SRVC	CUSTOMER			CUST
251	Subtotal - Customer Service & Information Expenses		14,925						
252	**Sales Expenses**								
253	Supervision	911.0	1,139,859		CUST ACCTS & SRVC	CUSTOMER			CUST
254	Demonstrating and Selling Expenses	912.0	25,289		CUST ACCTS & SRVC	CUSTOMER			CUST
255	Advertising Expenses	913.0	0						
256	Miscellaneous Sales Expenses	916.0	0						
257	Subtotal - Sales Expenses		1,165,148						
258	**Total Customer Accounts, Service, and Sales Expense**		4,838,172						

Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
259	**Administrative and General Expenses**								
260	Administrative and General Salaries	920.0	20,391,648	INT_LABOR					
261	Office Supplies and Expenses	921.0	2,742,248	INT_LABOR					
262	Administrative Expenses Transferred - Company	922.0	0						
263	Outside Services Employed	923.0	340,000	INT_LABOR					
264	Property Insurance	924.0	2,276,531	INT_TOTAL_PLANT					
265	Injuries and Damages	925.0	4,009,520	INT_LABOR					
266	Employee Pensions and Benefits	926.0	8,123,484	INT_LABOR					
267	Regulatory Commission Expenses	928.0	414,956	INT_RATEBASE					
268	General Advertising Expenses	930.1	(835)	INT_RATEBASE					
269	Miscellaneous General Expense	930.2	5,306,182	INT_TOTAL_PLANT					
270	Rents	931.0	4,626,382	INT_LABOR					
271	Maintenance of General Plant	935.0	1,156,447	INT_GENPT					
272	**Total Administrative and General Expenses**		49,386,564						
273	**TOTAL OPERATION AND MAINTENANCE EXPENSE**		393,708,355						
274	**Adjustments, Depreciation and Amortization Expense**								
275	**Depreciation Expense**								
276	**Intangible Plant**								
277	Organization	301.0	0	INT_LABOR	-	-	-	-	-
278	Franchises and Consents	302.0	0	-	-	-	-	-	-
279	Miscellaneous Intangible Plant	303.0	18,385,082	INT_LABOR	-	-	-	-	-
280	Subtotal - Intangible Plant		18,385,082						
281	**Other Production Plant**								
282	Land and Land Rights	310.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
283	Structures and Improvements	311.0	5,712,146	-	PRODUCTION	DEMAND	4CP_Demand	-	-
284	Boiler Plant Equipment	312.0	21,729,351	-	PRODUCTION	DEMAND	4CP_Demand	-	-
285	Engines and Engine Driven Generators	313.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
286	Turbogenerator Units	314.0	998,400	-	PRODUCTION	DEMAND	4CP_Demand	-	-
287	Accessory Electric Equipment	315.0	1,970,549	-	PRODUCTION	DEMAND	4CP_Demand	-	-
288	Miscellaneous Power Plant Equipment	316.0	1,231,001	-	PRODUCTION	DEMAND	4CP_Demand	-	-
289	Asset Retirement Costs for Steam Production	317.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
290	Subtotal - Other Production Plant		31,641,447						
291	**Other Production Plant**								
292	Land and Land Rights	340.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
293	Structures and Improvements	341.0	76,322	-	PRODUCTION	DEMAND	4CP_Demand	-	-
294	Fuel Holders, Producers and Accessories	342.0	70,847	-	PRODUCTION	DEMAND	4CP_Demand	-	-
295	Prime Movers	343.0	842,977	-	PRODUCTION	DEMAND	4CP_Demand	-	-
296	Generators	344.0	553,653	-	PRODUCTION	DEMAND	4CP_Demand	-	-
297	Accessory Electric Equipment	345.0	137,601	-	PRODUCTION	DEMAND	4CP_Demand	-	-
298	Miscellaneous Power Plant Equipment	346.0	24,331,594	-	PRODUCTION	DEMAND	4CP_Demand	-	-
299	Asset Retirement Costs for Other Production	347.0	0	-	PRODUCTION	DEMAND	4CP_Demand	-	-
300	Subtotal - Other Production Plant		26,012,993						

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301	**Other Production Plant**								
302	Land and Land Rights	350.0	143,300	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
303	Structures and Improvements	352.0	91,477	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
304	Station Equipment	353.0	3,139,593	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
305	Towers and Fixtures	354.0	17,043	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
306	Poles and Fixtures	355.0	5,951,193	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
307	Overhead Conductors and Devices	356.0	2,833,897	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
308	Underground Conduit	357.0	14,054	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
309	Underground Conductors and Devices	358.0	9,361	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
310	Road and Trails	359.0	0	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
311	ARO for Transmission Plant	359.1	0	-	TRANSMISSION	DEMAND	4CP_Demand	-	-
312	Subtotal - Other Production Plant		12,199,918						
313	**Distribution Plant**								
314	Land and land rights	360.0	1,177	INT_361-364	-	-	-	-	-
315	Structures and improvements	361.0	19,706	INT_STNS,POLES,LINES	-	-	-	-	-
316	Station equipment	362.0	4,013,204	-	SUBSTATION	DEMAND	NCP_PRI	-	-
317	Storage battery equipment	363.0	0	-	-	-	-	-	-
318	Poles, Towers and Fixtures	364.0	15,005,586	INT_364	-	-	-	-	-
319	Overhead Conductors and Devices	365.0	13,295,258	INT_365	-	-	-	-	-
320	Underground conduit	366.0	1,015,632	INT_367	-	-	-	-	-
321	Underground Conductors and Devices	367.0	2,912,001	INT_367	-	-	-	-	-
322	Transformers and Transformer Installations	368.0	1,749,229	INT_368	-	-	-	-	-
323	Services	369.0	1,993,032	-	ONSITE & METERING	CUSTOMER	-	-	SERV
324	Meters	370.0	1,852,884	-	ONSITE & METERING	CUSTOMER	-	-	MTRS
325	Installations on customers premises	371.0	192,489	-	LIGHTING PLANT	CUSTOMER	-	-	OUTDOOR-LIGHT
326	Street lighting and signal systems	373.0	431,653	-	LIGHTING PLANT	CUSTOMER	-	-	STREET-LIGHT
327	Subtotal - Distribution Plant		42,481,852						
328	**General Plant**								
329	Land and Land Rights	389.0	0	INT_LABOR	-	-	-	-	-
330	Structures and Improvements	390.0	1,139,965	INT_LABOR	-	-	-	-	-
331	Office Furniture and Equipment	391.0	1,445,296	INT_LABOR	-	-	-	-	-
332	Transportation Equipment	392.0	1,805,524	INT_LABOR	-	-	-	-	-
333	Stores Equipment	393.0	22,940	INT_LABOR	-	-	-	-	-
334	Tools, Shop and Garage Equipment	394.0	369,878	INT_LABOR	-	-	-	-	-
335	Laboratory Equipment	395.0	92,074	INT_LABOR	-	-	-	-	-
336	Power Operated Equipment	396.0	245,204	INT_LABOR	-	-	-	-	-
337	Communication Equipment	397.0	1,505,059	INT_LABOR	-	-	-	-	-
338	Miscellaneous Equipment	398.0	127,525	INT_LABOR	-	-	-	-	-
339	Miscellaneous Equipment-DLC	398.0	154,194	-	PRODUCTION	DEMAND	4CP_Demand	-	-
340	Subtotal - General Plant		6,907,660						

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341	**Amortization Expense**								
342	Regulatory Amortization - TDISC	407.4	7,935,299	ST (60%)_TRANSM (40%)_PLANT					
343	Regulatory Amortization - CECA	407.4	167,953		PRODUCTION	DEMAND	4CP_Demand		
344	Regulatory Amortization - ECA	407.4	24,657,372		PRODUCTION	DEMAND	4CP_Demand		
345	Regulatory Amortization - AMI	407.4	1,643,527		CUST ACCTS & SRVC	CUSTOMER			CUST
346	Regulatory Amortization - CT	407.4	118,495		PRODUCTION	DEMAND	4CP_Demand		
347	Pro Forma Amortization Expense - Deferred Medicare Tax Liability	407.4	(347,401)	INT_LABOR					
348	Subtotal - Amortization Expense		34,175,245						
349	**Total Adjustments, Depreciation and Amortization Expense**		171,804,198						
350	**Taxes**								
351	**Taxes Other Than Income Taxes**								
352	Taxes Other Than Income Taxes - Property	408.1	9,516,863	INT_TOTAL_PLANT					
353	Taxes Other Than Income Taxes - Payroll	408.1	2,783,210	INT_LABOR					
354	Taxes Other Than Income Taxes - Other	408.0	0						
355	Taxes Other Than Income Taxes - Other	408.0	0						
356	Investment Tax Credits		0	INT_RATEBASE					
357	Subtotal - Taxes Other Than Income Taxes		12,300,073						
358	**Income Taxes**								
359	State Income Tax	409.0	(0)	INT_RATEBASE					
360	Federal Income Tax	409.0	11,324,453	INT_RATEBASE					
361	Deferred Federal & State Income Taxes	410.0	3,589,036	INT_TOTAL_PLANT					
362	Subtotal - Income Taxes		14,913,489						
363	**Total Taxes**		27,213,562						
364	**REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**								
365	**Test Year Expenses at Current Rates**		592,726,115	n/a	n/a	n/a	n/a	n/a	n/a
366	**Return on Rate Base**		187,518,958	INT_RATEBASE					
367	**Gross Up Items**								
368	Gross-up State Income Tax		4,584,096	INT_RATEBASE					
369	Gross-up Federal Income Tax		18,683,465	INT_RATEBASE					
370	Gross-up IURC Assessment		137,915	INT_RATEBASE					
371	Gross-up Bad Debts		281,918	INT_RATEBASE					
372	**TOTAL REVENUE REQUIREMENT AT EQUAL RATES OF RETURN**		**803,932,466**						

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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
373	INTERNAL ALLOCATION FACTORS								
				Occurrences					
374	INT_STEAM_PROD_PT		774,486,722	0					
375	INT_OTHER_PROD_PT		855,100,022	0					
376	INT_TRANSMISSION_PT		574,404,982	0					
377	INT_DIST_PLANT		1,346,647,831	0					
378	INT_TOTAL_PLANT		3,903,197,879	5					
379	INT_RATEBASE		2,769,851,666	10					
380	INT_TRANS_OPS		20,022,132	0					
381	INT_TRANS_MAINT		3,184,499	0					
382	INT_DIST_OPS		1,478,517	3					
383	INT_DIST_MAINT		10,942,593	2					
384	INT_361-364		559,325,756	3					
385	INT_364		297,854,492	2					
386	INT_365		312,095,266	4					
387	INT_367		165,164,611	7					
388	INT_368		103,114,848	2					
389	INT_STNS,POLES,LINES		869,881,492	3					
390	INT_T&D_OH_CNDT		418,889,136	0					
391	INT_LABOR		25,452,949	44					
392	INT_REVREQ		803,932,466	0					
393	INT_GENPT		153,998,437	1					
394	INT_TOTAL_PLANT_EXCL INT		3,704,637,994	0					
395	INT_DIST (60%)_TRANSM (40%)_PLANT		1,037,750,691	2					

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Line No.	Account Description	FERC Account	Account Balance	Internal Allocation Factor	Functional Allocation Factor	Classification Allocation Factor	Demand Allocation Factor	Energy Allocation Factor	Customer Allocation Factor
				Revenue/Margin Allocation Factor	Revenue Category				
397	Operating Revenue								
398	Base Rate Revenue		267,328,652	REV	Base Rate Revenue				
399	Fuel Cost Revenue		207,300,587	REV_ENERGY	Fuel Cost Revenue				
400	Special Contract Revenue		30,156,859	INT_REVREQ	Special Contract Revenue				
401	Non-Firm Revenue		14,611,626	INT_REVREQ	Sale for Resale and Transmission Revenue				
402	Forfeited Discounts		2,551,683	REV_FORFEITED	Other Revenue				
403	Reconnect Charge		237,837	REV_RECONNECT	Other Revenue				
404	Returned Check Charge		104,726	REV_NFS	Other Revenue				
405	Securitization Fees		245,725	INT_REVREQ	Other Revenue				
406	Interdepartmental Sales		100,367	INT_REVREQ	Other Revenue				
407	Rent From Property		5,062,099	INT_REVREQ	Other Revenue				
408	LRAM Incentive		0	INT_REVREQ	Other Revenue				
409	Rider Revenue		99,379,048	REV_RIDER	Rider Revenue				
410	Rider Revenue_Special Contract		12,267,532	INT_REVREQ	Special Contract Revenue				
411	Variable Production Revenue_Special Contract		4,870,592	REV_VP	Special Contract Revenue				
412	Variable Production Revenue		18,054,808	REV_VP	Variable Production Revenue				
413	Transmission Revenue		8,758,794	INT_REVREQ	Sale for Resale and Transmission Revenue				
414	Fuel Cost Revenue_Special Contract		52,891,914	REV_ENERGY	Fuel Cost Revenue_Special Contract				
415	Total Operating Revenue		723,922,849						
416	NET INCOME AT CURRENT RATES		131,196,735						
417	EARNINGS (DEFICIENCY)/SURPLUS		(56,322,223)						
418	REQUIRED INCOME INCREASE/(DECREASE)		56,322,223						
419	REVENUE GROSS-UP		23,687,393						
420	REQUIRED REVENUE INCREASE/(DECREASE)		80,009,617						

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Schedule 5 - Allocation Factors (External, Functionalization & Classification, and Internal)

Line No.	Category Description	Total System	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
1	**Allocation Factor Basis**									
2	INT_STEAM_PROD_PT	774,486,722	352,505,393	1,191,275	13,075,311	231,912,090	167,918,427	7,884,226	-	-
3	INT_OTHER_PROD_PT	855,100,022	389,196,303	1,315,270	14,436,270	256,050,915	185,396,401	8,704,865	-	-
4	INT_TRANSMISSION_PT	574,404,982	261,438,767	883,519	9,697,421	171,999,669	124,538,198	5,847,407	-	-
5	INT_DIST_PLANT	1,346,647,831	730,605,185	6,098,051	36,398,072	350,500,249	190,111,038	1,222	8,391,350	24,542,663
6	INT_TOTAL_PLANT	3,903,197,879	1,920,914,445	11,376,172	82,940,564	1,099,503,552	729,052,713	25,156,856	8,449,008	25,804,568
7	INT_RATEBASE	2,769,851,666	1,348,773,734	7,158,066	54,931,192	792,545,219	531,408,163	18,363,947	4,902,484	11,768,861
8	INT_TRANS_OPS	20,022,132	9,113,015	30,797	338,025	5,995,422	4,341,049	203,824	-	-
9	INT_TRANS_MAINT	3,184,499	1,449,416	4,898	53,762	953,566	690,439	32,418	-	-
10	INT_DIST_OPS	1,478,517	1,101,249	23,725	79,564	191,577	77,842	4,169	151	240
11	INT_DIST_MAINT	10,942,593	5,419,540	23,181	194,903	3,164,137	1,947,810	24,992	20,175	147,855
12	INT_361-364	559,325,756	282,114,921	1,205,013	9,998,733	161,542,246	101,383,645	-	1,190,898	1,890,300
13	INT_364	297,854,492	152,825,448	652,772	5,416,448	87,638,508	49,652,190	-	645,125	1,024,001
14	INT_365	312,095,266	159,837,858	682,724	5,664,982	91,645,421	52,518,566	-	674,727	1,070,988
15	INT_367	165,164,611	88,888,042	379,672	3,150,375	51,175,844	20,599,861	-	375,225	595,591
16	INT_368	103,114,848	71,894,808	1,288,367	4,473,573	16,238,754	8,974,567	-	94,608	150,171
17	INT_STNS,POLES,LINES	869,881,492	441,171,985	1,884,402	15,636,042	252,740,364	153,630,314	-	1,862,328	2,956,056
18	INT_T&D_OH_CNDT	418,889,136	208,444,779	846,989	7,467,935	123,623,748	75,672,815	1,087,155	674,727	1,070,988
19	INT_LABOR	2545294946%	1352963438%	13716416%	67598180%	641777630%	440053284%	19575488%	419932%	9190578%
20	INT_REVREQ	803,932,466	366,942,931	2,231,616	15,795,627	225,323,157	180,998,832	8,444,677	1,265,777	2,929,848
21	INT_GENPT	153,998,437	81,623,362	818,032	4,060,118	38,975,196	26,759,846	1,192,042	24,899	544,943
22	INT_TOTAL_PLANT_EXCL INT	3,704,637,994	1,815,369,009	10,306,146	77,667,192	1,049,438,120	694,723,910	23,629,762	8,416,249	25,087,606
23	INT_DIST (60%)_TRANSM (40%)_PLA	1,037,750,691	542,938,618	4,012,238	25,717,812	279,100,017	163,881,902	2,339,696	5,034,810	14,725,598
24	**Allocation Factor %**									
25	INT_STEAM_PROD_PT	100.0%	45.5%	0.2%	1.7%	29.9%	21.7%	1.0%	0.0%	0.0%
26	INT_OTHER_PROD_PT	100.0%	45.5%	0.2%	1.7%	29.9%	21.7%	1.0%	0.0%	0.0%
27	INT_TRANSMISSION_PT	100.0%	45.5%	0.2%	1.7%	29.9%	21.7%	1.0%	0.0%	0.0%
28	INT_DIST_PLANT	100.0%	54.3%	0.5%	2.7%	26.0%	14.1%	0.0%	0.6%	1.8%
29	INT_TOTAL_PLANT	100.0%	49.2%	0.3%	2.1%	28.2%	18.7%	0.6%	0.2%	0.7%
30	INT_RATEBASE	100.0%	48.7%	0.3%	2.0%	28.6%	19.2%	0.7%	0.2%	0.4%
31	INT_TRANS_OPS	100.0%	45.5%	0.2%	1.7%	29.9%	21.7%	1.0%	0.0%	0.0%
32	INT_TRANS_MAINT	100.0%	45.5%	0.2%	1.7%	29.9%	21.7%	1.0%	0.0%	0.0%
33	INT_DIST_OPS	100.0%	74.5%	1.6%	5.4%	13.0%	5.3%	0.3%	0.0%	0.0%
34	INT_DIST_MAINT	100.0%	49.5%	0.2%	1.8%	28.9%	17.8%	0.2%	0.2%	1.4%
35	INT_361-364	100.0%	50.4%	0.2%	1.8%	28.9%	18.1%	0.0%	0.2%	0.3%
36	INT_364	100.0%	51.3%	0.2%	1.8%	29.4%	16.7%	0.0%	0.2%	0.3%
37	INT_365	100.0%	51.2%	0.2%	1.8%	29.4%	16.8%	0.0%	0.2%	0.3%
38	INT_367	100.0%	53.8%	0.2%	1.9%	31.0%	12.5%	0.0%	0.2%	0.4%
39	INT_368	100.0%	69.7%	1.2%	4.3%	15.7%	8.7%	0.0%	0.1%	0.1%
40	INT_STNS,POLES,LINES	100.0%	50.7%	0.2%	1.8%	29.1%	17.7%	0.0%	0.2%	0.3%
41	INT_T&D_OH_CNDT	100.0%	49.8%	0.2%	1.8%	29.5%	18.1%	0.3%	0.2%	0.3%
42	INT_LABOR	100.0%	53.2%	0.5%	2.7%	25.2%	17.3%	0.8%	0.0%	0.4%
43	INT_REVREQ	100.0%	45.6%	0.3%	2.0%	28.0%	22.5%	1.1%	0.2%	0.4%
44	INT_GENPT	100.0%	53.0%	0.5%	2.6%	25.3%	17.4%	0.8%	0.0%	0.4%
45	INT_TOTAL_PLANT_EXCL INT	100.0%	49.0%	0.3%	2.1%	28.3%	18.8%	0.6%	0.2%	0.7%
46	INT_DIST (60%)_TRANSM (40%)_PLANT	100.0%	52.3%	0.4%	2.5%	26.9%	15.8%	0.2%	0.5%	1.4%

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule 5 - External Allocation Factors

No.	Code	Description	Total	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	CUSTOMER EXTERNAL ALLOCATORS										
1	CUST		100.0%	85.5%	2.1%	6.4%	6.0%	0.1%	0.0%	0.0%	0.0%
		Number Customers	156,171	133,577	3,219	9,932	9,316	106	1	-	19
2	CUST-BILL		100.0%	85.5%	2.1%	6.4%	6.0%	0.1%	0.0%	0.0%	0.0%
		Number Customers Bills	1,873,820	1,602,925	38,634	119,184	111,793	1,272	12		
3	CUST_PRI		100.0%	85.5%	2.1%	6.4%	6.0%	0.1%	0.0%	0.0%	0.0%
		Number of Customers Using Primary System	156,146	133,577	3,219	9,932	9,316	101	-		
4	CUST_SEC		100.0%	85.6%	2.1%	6.4%	5.9%	0.0%	0.0%	0.0%	0.0%
		Number of Customers Using Secondary System	155,982	133,577	3,219	9,932	9,254	-	-		
5	MTRS		100.0%	82.8%	2.0%	6.4%	8.7%	0.1%	0.0%	0.0%	0.0%
		Relative Weighting Factor		1.00	1.00	1.04	1.50	1.23	1.23		
		Relative Cost	161,252	133,577	3,219	10,315	14,009	130	1		
6	SERV		100.0%	76.4%	1.8%	10.1%	11.6%	0.1%	0.0%	0.0%	0.0%
		Relative Weighting Factor		1.00	1.00	1.78	2.17	1.73	1.73		
		Relative Cost	174,947	133,577	3,219	17,723	20,242	184	2		
7	STREET-LIGHT		100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
		Street Lights	1	-	-	-	-	-	-	-	1
8	OUTDOOR-LIGHT		100.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%	0.0%
		Outdoor Lighting	1	-	-	-	-	-	-	1	-
9	MTR_READ		100.0%	0.0%	0.0%	0.0%	0.0%	99.1%	0.9%	0.0%	0.0%
		ACCT - 902_Meter reading expenses	107					106	1		
10	UNCOLL		100.0%	97.2%	0.4%	1.2%	1.2%	0.0%	0.0%	0.0%	0.0%
		ACCT - 904_Uncollectible accounts	(2,385,325)	(2,317,672)	(9,648)	(29,765)	(27,919)	(318)	(3)	-	-

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule 5 - External Allocation Factors

No.	Code	Description	Total	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	ENERGY AND REVENUE EXTERNAL ALLOCATORS										
11	REV		100.0%	49.4%	0.2%	2.2%	28.4%	18.0%	0.7%	0.4%	0.7%
		Total Revenue_Less Fuel Cost	267,328,655	132,139,578	530,561	5,953,227	75,824,903	48,031,238	1,868,205	1,152,148	1,828,794
12	REV_ENERGY		100.0%	36.65%	0.19%	1.61%	28.57%	30.68%	1.82%	0.19%	0.30%
		Total Fuel Cost Revenue	195,282,190	71,566,370	368,433	3,150,305	55,786,093	59,910,377	3,547,537	368,368	584,707
13	REV_RIDER		100.0%	50.2%	0.5%	2.7%	29.9%	15.8%	0.8%	0.0%	0.1%
		Total Rider	99,379,046	49,842,142	487,680	2,724,122	29,673,720	15,662,292	814,423	29,159	145,507
14	ENERGY		100.0%	35.9%	0.2%	1.6%	28.3%	31.6%	1.9%	0.2%	0.3%
		kWh Sales	3,904,507,404	1,399,798,865	7,362,997	62,270,627	1,103,811,583	1,235,650,954	75,708,000	7,693,136	12,211,243
15	REV_LATE_FEE		100.0%	65.2%	5.0%	15.3%	14.4%	0.2%	0.0%	0.0%	0.0%
		Late Payment Fees	2,138,215	1,393,541	106,202	327,629	307,313	3,497	33	-	-
16	REV_FORFEITED		100.0%	44.8%	0.2%	2.1%	28.8%	22.2%	1.1%	0.3%	0.4%
		Forfeited Discounts	2,182,387	977,503	5,310	45,631	629,137	484,381	24,822	5,889	9,713
17	REV_RECONNECT		100.0%	95.2%	0.7%	2.1%	2.0%	0.0%	0.0%	0.0%	0.0%
		Reconnection Charge Revenue	51,711	49,208	357	1,101	1,033	12	0	-	-
18	REV_NFS		100.0%	94.8%	0.7%	2.3%	2.2%	0.0%	0.0%	0.0%	0.0%
		Returned Check Charge Revenue	152,777	144,808	1,137	3,506	3,289	37	0	-	-
19	REV_MISC		100.0%	56.7%	2.5%	8.4%	20.8%	10.8%	0.5%	0.1%	0.2%
		Total Misc Revenue	4,525,089	2,565,060	113,005	377,868	940,772	487,926	24,855	5,889	9,713
20	REV_VP		100.0%	36.3%	0.2%	1.6%	28.6%	31.0%	1.8%	0.2%	0.3%
		Variable Production Revenue	18,054,808	6,551,059	34,459	291,427	5,155,612	5,597,499	331,601	36,004	57,149
21	REV_PROPOSED_VP		100.0%	36.2%	0.2%	1.6%	28.5%	31.2%	1.9%	0.2%	0.3%
		Proposed Variable Production Revenue	6,549,773	2,368,171	12,457	105,349	1,866,940	2,041,470	121,712	13,015	20,659

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule S - External Allocation Factors

No.	Code	Description	Total	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
	DEMAND ALLOCATORS										
22	NCP_SEC		100.0%	61.3%	0.3%	2.2%	35.6%	0.0%	0.0%	0.3%	0.4%
		Non-Coincident Peak Demand_Secondary (kW)	739,741	453,262	1,936	16,065	263,528	-	-	1,913	3,037
23	NCP_PRI		100.0%	49.4%	0.2%	1.8%	28.3%	19.8%	0.0%	0.2%	0.3%
		Non-Coincident Peak Demand_Primary (kW)	916,803	453,262	1,936	16,065	259,087	181,503	-	1,913	3,037
24	DEM_UNIT										
		Demand kW	8	1	1	1	1	1	1	1	1
25	12CP_Demand		100.0%	44.4%	0.2%	1.7%	28.4%	24.0%	1.3%	0.0%	0.1%
		12_Coincident Peak Demand	678,015	300,715	1,296	11,651	192,262	162,477	8,789	319	506
26	4CP_Demand		100.0%	45.5%	0.2%	1.7%	29.9%	21.7%	1.0%	0.0%	0.0%
		4_Coincident Peak Demand	854,192	388,783	1,314	14,421	255,779	185,199	8,696	-	-

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule 5 - Functionalization Summary

	Replacement Costs	% of Total
Poles Primary	$ 158,125,353	84%
Poles Secondary	$ 29,665,316	16%
	$ 187,790,669	100%

	Replacement Costs	% of Total
Overhead Primary	$ 263,915,794	85%
Overhead Secondary	$ 46,061,696	15%
	$ 309,977,490	100%

	Replacement Costs	% of Total
Underground Primary	$ 134,491,649	63%
Underground Secondary	$ 77,557,582	37%
	$ 212,049,231	100%

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S2: Allocated Cost of Service Study
Schedule 5 - Transformer Classification Summary

Transformers and Transformer Installations	Quantity	Total Replacement Cost	Zero Intercept Unit Cost	Customer Component	Customer Component (%)	Demand Component (%)
Overhead	38,002	$ 108,547,706	$ 1,600	$ 60,815,919	56.03%	43.97%
Padmount	18,992	$ 109,728,498	$ 3,238	$ 61,499,914	56.05%	43.95%
Total	**56,994**	**$ 218,276,204**	**$ -**	**$ 122,315,833**	**56.04%**	**43.96%**
					Rounded	**44.00%**

CenterPoint Energy Indiana
Electric Class Cost of Service Study
12 Months Ended Dec 31, 2025
Petitioner's Exhibit No. 18-S, Attachment JDT-S3: Revenue Apportionment
Schedule 1 - Proposed Revenue Apportionment

Line No.	Category Description	Total System	Residential (RS)	Water Heating (B)	Small General Service (SGS)	Demand General Service (DGS)	Large Power Service (LP)	High Load Factor Service (HLF)	Outdoor Lighting (OL)	Street Lighting (SL)
1	Total Revenue at Current Rates	$ 723,922,849	$ 319,622,569	$ 1,759,173	$ 14,704,649	$ 207,073,126	$ 167,222,380	$ 8,607,350	$ 1,836,828	$ 3,096,774
2	Total Revenue Requirement at Equal Rates of Return	$ 803,932,466	$ 366,942,931	$ 2,231,616	$ 15,795,627	$ 225,323,157	$ 180,998,832	$ 8,444,677	$ 1,265,777	$ 2,929,848
3	Total Revenue (Deficiency)/Surplus	$ (80,009,617)	$ (47,320,362)	$ (472,442)	$ (1,090,978)	$ (18,250,031)	$ (13,776,453)	$ 162,673	$ 571,051	$ 166,926
4	Percent Change at Equal Rates of Return	11.05%	14.81%	26.86%	7.42%	8.81%	8.24%	-1.89%	-31.09%	-5.39%
5	Multiple of system average increase required for parity	1.00	1.34	2.43	0.67	0.80	0.75	(0.17)	(2.81)	(0.49)
6	**Proposed Multiple of system average increase**	**1.00**	**1.34**	**1.50**	**0.67**	**0.80**	**0.75**	**-0.17**	**0.00**	**0.00**
7	Target Percentage Increase	11.05%	14.81%	16.58%	7.42%	8.81%	8.24%	3.62%	0.00%	0.00%
8	Targeted Increase	$ 81,041,052	$ 47,320,362	$ 291,642	$ 1,090,978	$ 18,250,031	$ 13,776,453	$ 311,586	$ -	$ -
9	Targeted Revenue	$ 804,963,901	$ 366,942,931	$ 2,050,815	$ 15,795,627	$ 225,323,157	$ 180,998,832	$ 8,918,936	$ 1,836,828	$ 3,096,774
10	*Include in Allocation of Delta*		*yes*	*no*	*yes*	*yes*	*yes*	*no*	*no*	*no*
11	Allocation of Delta	$ (1,031,435)	$ (479,656)	$ -	$ (20,648)	$ (294,535)	$ (236,596)	$ -	$ -	$ -
12	**Proposed Increase/ (Decrease)**	**$ 80,009,617**	**$ 46,840,706**	**$ 291,642**	**$ 1,070,331**	**$ 17,955,496**	**$ 13,539,857**	**$ 311,586**	**$ -**	**$ -**
13	Resulting Increase %	11.05%	14.66%	16.58%	7.28%	8.67%	8.10%	3.62%	0.00%	0.00%
14	Multiple of System Increase		1.33	1.50	0.66	0.78	0.73	0.33	-	-
15	**Proposed Revenue**	**$ 803,932,466**	**$ 366,463,275**	**$ 2,050,815**	**$ 15,774,980**	**$ 225,028,622**	**$ 180,762,236**	**$ 8,918,936**	**$ 1,836,828**	**$ 3,096,774**
16	Proposed Rate of Return	6.77%	6.74%	4.63%	6.74%	6.74%	6.73%	8.96%	16.62%	7.98%
17	Proposed Revenue to Cost Ratio	1.000	0.999	0.919	0.999	0.999	0.999	1.056	1.451	1.057
18	Current Parity Ratio	1.000	0.967	0.875	1.034	1.021	1.026	1.132	1.612	1.174

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S5: Updated Tracker Allocations
Schedule 1-Energy Allocation

Line	Customer Classes	Energy Usage	Resulting % Allocation
1	Residential (RS)	1,399,798,865	28.11%
2	Water Heating (B)	7,362,997	0.15%
3	Small General Service (SGS)	62,270,627	1.25%
4	Demand General Service (DGS)	1,022,639,369	20.54%
5	Off Season Service (OSS)	81,172,214	1.63%
6	Large Power Service (LP)[1]	2,310,836,770	46.41%
7	High Load Factor Service (HLF)	75,708,000	1.52%
8	Outdoor Lighting (OL)	7,693,136	0.15%
9	Street Lighting (SL)	12,211,243	0.25%
10	**Total**	**4,979,693,220**	

[1] Includes BAMP-Base

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S5: Updated Tracker Allocations
Schedule 2-TDSIC Allocation

Line	Customer Classes	Transmission Allocation %	Distribution Allocation %	EADIT Credit Allocation %
1	Residential (RS)	33.34%	54.27%	46.32%
2	Water Heating (B)	0.08%	0.38%	0.26%
3	Small General Service (SGS)	1.12%	2.50%	1.98%
4	Demand General Service (DGS)	22.80%	24.34%	23.75%
5	Off Season Service (OSS)	1.75%	1.87%	1.82%
6	Large Power Service (LP)/BAMP	39.35%	15.45%	24.52%
7	High Load Factor Service (HLF)	1.57%	0.16%	0.70%
8	Outdoor Lighting (OL)/Street Lighting (SL)	0.00%	1.03%	0.64%
9	**Total**	**100%**	**100%**	**100%**

Cause No. 45990

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S5: Updated Tracker Allocations
Schedule 3-Production Allocation

Line	Customer Classes	4CP for Trackers	Resulting % Allocation
1	Residential (RS)	388,783	38.31%
2	Water Heating (B)	1,314	0.13%
3	Small General Service (SGS)	14,421	1.42%
4	Demand General Service (DGS)	240,623	23.71%
5	Off Season Service (OSS)	15,156	1.49%
6	Large Power Service (LP)[1]	345,822	34.08%
7	High Load Factor Service (HLF)	8,696	0.86%
8	Outdoor Lighting (OL)	-	0.00%
9	Street Lighting (SL)	-	0.00%
10	**Total**	**1,014,814**	

[1] Includes BAMP-Base

Cause No. 45990

CenterPoint Energy Indiana
Electric Class Cost of Service Study
Petitioner's Exhibit No. 18-S, Attachment JDT-S5: Updated Tracker Allocations
Schedule 4-Rate Base Allocation

Line	Customer Classes	Production Rate Base	Transmission Rate Base	All Other Rate Base	Total Rate Base	Resulting % Allocation
1	Residential (RS)	$ 510,313,916	$ 163,955,223	$ 540,306,886	$ 1,214,576,026	43.85%
2	Water Heating (B)	$ 1,724,581	$ 706,511	$ 4,419,830	$ 6,850,921	0.25%
3	Small General Service (SGS)	$ 18,928,826	$ 6,352,183	$ 24,919,294	$ 50,200,304	1.81%
4	Demand General Service (DGS)	$ 315,840,232	$ 96,769,742	$ 260,236,520	$ 672,846,494	24.29%
5	Off Season Service (OSS)	$ 19,893,546	$ 8,055,053		$ 27,948,599	1.01%
6	Large Power Service (LP)	$ 435,127,133	$ 157,588,857	$ 144,979,431	$ 737,695,421	26.63%
7	BAMP-Base	$ 18,797,144	$ 7,476,221		$ 26,273,365	0.95%
8	High Load Factor Service (HLF)	$ 11,413,812	$ 4,792,035	$ 179,333	$ 16,385,180	0.59%
9	Outdoor Lighting (OL)	$ -	$ 173,866	$ 4,884,770	$ 5,058,636	0.18%
10	Street Lighting (SL)	$ -	$ 275,976	$ 11,740,743	$ 12,016,719	0.43%
11	**Total**	**$ 1,332,039,189**	**$ 446,145,668**	**$ 991,666,808**	**$ 2,769,851,666**	