Filed: 10/14/2020 3:12 PM

IN THE
INDIANA COURT OF APPEALS

CAUSE NO. 20A-EX-01404

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR, DUKE INDUSTRIAL GROUP, SIERRA CLUB, CITIZENS ACTION COALITION OF INDIANA, INC., ENVIRONMENTAL WORKING GROUP, and INDIANA COMMUNITY ACTION ASSOCIATION,	Appeal from the Indiana Utility Regulatory Commission
Appellants (Statutory Party and Intervenors below),	Cause No. 45253
v.	Hon. James F. Huston, Chairman Hon. Sarah E. Freeman, Hon. Stefanie Krevda, Hon. David L. Ober, Hon. David E. Ziegner, Commissioners
DUKE ENERGY INDIANA, LLC,	Hon. David E. Veleta, Senior Administrative Law Judge
Appellee (Petitioner below).	

JOINT APPELLANTS' APPENDIX
(OUCC, Duke Industrial Group, Sierra Club, CAC, EWG & INCAA)

Volume VIII of IX
(Pages 1 – 220)

Todd A. Richardson, Atty. No. 16620-49
Joseph P. Rompala, Atty. No. 25078-49
Tabitha L. Balzer, Atty. No. 29350-53
Aaron A. Schmoll, Atty. No. 20359-49
Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282-0003
Phone: (317) 639-1210 / Fax: (317) 639-4882
Email: TRichardson@Lewis-Kappes.com
JRompala@Lewis-Kappes.com
TBalzer@Lewis-Kappes.com
ASchmoll@Lewis-Kappes.com
Counsel for Duke Industrial Group

ratemaking purposes, as well as to remove the deferred income taxes related to the Gas Pipeline Lease. Ms. Douglas explained that the Company made certain other adjustments to the accumulated deferred income tax balances to remove deferred taxes associated with impairments taken by the Company for accounting books purposes but which are not used for tax purposes. As approved by the Commission in its IGCC-4S1 Order, the Company excluded deferred income taxes associated with the amount of the IGCC capital investment in excess of the agree-upon Hard Cost Cap, including Additional AFUDC. The Company similarly removed the deferred taxes associated with the non-AMI legacy meter impairments taken by the Company, so that customers will neither be harmed by nor benefit from the inclusion of related deferred taxes in the capital structure for the portions of the IGCC plant and non-AMI legacy meters that shareholders are paying for, not customers. Ms. Douglas explained an adjustment to remove the deferred income tax asset balances related to the Company's deferred utilization of ITCs and to include the unamortized balance of the regulatory liability for the EDIT amounts resulting from the 2017 Tax Cuts and Jobs Act and from other previous state and federal tax changes as an additional zero cost source of capital component in the calculation. Finally, she explained that short-term debt has been excluded from the capital structure, consistent with previous Commission orders. However, the Company has included an $150,000,000 inter-company notes payable for Commercial Paper issued by Duke Energy Corporation on behalf of the Company that is part of the Company's permanent long- term financing.

ii. OUCC's and Intervenors' Evidence. OUCC Witness Kollen testified that the Company understated the Accumulated Deferred Income Taxes included in capitalization as cost-free capital. First, he proposed adjustments to ADIT to reflect the rate base adjustments proposed by the OUCC. Next, he proposed a number of adjustments to ADIT for what he characterized as the Company's failure to remove certain per books ADIT amounts through *pro forma* adjustments for ratemaking purposes. Mr. Kollen claimed the Company failed to remove certain per books ADIT amounts through *pro forma* adjustments for ratemaking purposes. As a general ratemaking principle, he said the ADIT reflected in capitalization as cost-free capital should match the rate base or other ratemaking treatment for the underlying temporary difference that gave rise to the ADIT. In Mr. Kollen's opinion, if the underlying temporary difference is not reflected as an addition to or subtraction from rate base, then the related liability or asset ADIT should not be added to or subtracted from the ADIT included in capitalization. Mr. Kollen indicated the ADIT amounts that incorrectly reduce (on a net basis) the ADIT included in capitalization were shown in a table set forth in his testimony, along with the reason why it should not be included in rate base. The positive amounts shown on the table are asset ADIT that incorrectly reduced the ADIT included in capitalization and the negative amounts are the liability ADIT that incorrectly increased the ADIT included in capitalization. Mr. Kollen then summed the effects on the retail revenue requirement of removing these ADIT amounts from the ADIT included in capitalization and showed the effect on a single line item on the table in the Summary section of his testimony. The effect of Mr. Kollen's adjustments is a $10.559 million reduction in the retail revenue requirement due to the increase in ADIT included in capitalization as cost-free capital.

FEA witness O'Donnell recommends the Commission reduce the common equity ratio to reflect a capital structure of 50% common equity and 50% long-term debt. He testified that the basis for his recommendation are the equity ratio requested by the Company, compared to the equity ratio of the proxy group, the average allowed equity ratio by state regulators across the country in 2018, and the equity ratio of Duke Energy Corp., the parent company of Duke Energy Indiana.

iii. Petitioner's Rebuttal Evidence. Ms. Douglas took issue with Mr. Kollen's recommendation for certain additional adjustments to the Company's zero cost ADIT balance included in capital structure. She pointed out that there is no Indiana statutory or regulatory requirement to exclude from the capital structure all deferred income tax balances that are associated with working capital or other items not included in rate base or operating income for retail jurisdictional purposes. She noted that the Commission previously approved Duke Energy Indiana's capital structure that included deferred income tax balances with only the FAS109 adjustment in in Cause No. 42359, approved May 18, 2004. Since then, she stated, the Commission has approved the use of the same capital structure components and methodology in many rate adjustment rider filings, most recently in Cause No. 44720 - TDSIC 6 approved on October 10, 2019. The capital structure used in these rider filings included deferred income tax balances with the limited adjustments she supported in her direct testimony. Furthermore, she testified, the Company does not maintain its capital structure for the retail jurisdictional business separate from the rest of its business. Rather, it manages one Duke Energy Indiana capital structure, and it is assumed all parts of the business benefit.

After reviewing Mr. Kollen's recommendations, Ms. Douglas stated the following three items (MGP Sites, Charitable Contribution Carryover and RUS Obligation—Contract Reserve) appeared to be related solely to non-jurisdictional expense activity and may be appropriate to exclude from the regulatory capital structure. Ms. Douglas also testified that, although this is not an adjustment the Company has historically made, the Company is amenable to removing non-utility items from the deferred income tax balance in its capital structure for MGP, RUS, and charitable contributions. The Company disagrees with Mr. Kollen's other recommendations in this regard, as they are based on the OUCC's proposed rate base adjustments, with which the Company disagrees.

Ms. Douglas indicated that as a rate mitigation measure, and with Commission approval, the Company agrees to remove the MGP and RUS obligation deferred tax items (as well as the charitable contributions issue if the Commission believes it is material) from the deferred tax balance included in the regulatory capital structure.

Mr. Sullivan responded to Mr. O'Donnell's recommendation that the Commission authorize a 50% equity ratio for the Company. Mr. Sullivan testified that the basis in which Mr. O'Donnell forms his recommendation is flawed. More specifically, he stated, none of the comparative equity ratios Mr. O'Donnell points to are applicable to Duke Energy Indiana's equity ratio for rate-setting purposes. He testified that Mr. O'Donnell's first comparative ratio of 50.40% is the average equity ratio of a proxy group consisting of 19 publicly-traded utility companies that Mr. O'Donnell selected for this analysis. While a proxy group average is a valid approach at comparing equity ratios, he stated, the proxy group Mr. O'Donnell chose to include is primarily comprised of utility holding companies where the equity ratios will be impacted by the consolidated capital structure of all regulated and non-regulated operations. He testified that comparing the capital structure of a holding company including numerous jurisdictions and/or non-regulated operations with that of a state-regulated utility is not a good comparison for several reasons, the largest of which being holding companies are not subject to regulated capital structures and tend to carry higher consolidated leverage than their regulated subsidiaries, resulting in lower equity ratios than their utility subsidiaries. Pointing to Mr. Hevert's Exhibit 41-U (RBH), Mr. Sullivan stated that an evaluation of the capital structures of the regulated utilities that are owned by the holding companies comprising Witness O'Donnell's proxy group, shows the average equity ratio of this larger universe of utilities stays above 53.00% for each of the past eight quarters (Q3 2017 through Q2 2019). Mr. Sullivan next addressed Mr. O'Donnell's reliance on a 48.70% "average allowed equity ratio by state regulators across the country in 2018." Mr. Sullivan pointed out that on the preceding of his testimony, Mr. O'Donnell refers to 48.70% as being the average common equity ratio from 2004 through 2018. In fact, Mr. Sullivan noted, Table 5 of Mr. O'Donnell's testimony illustrates how common equity ratios across the country have trended 200 basis points higher when comparing the U.S. average equity ratio in 2018 back to the U.S. average equity ratio in 2004. Mr. Sullivan noted that Duke Energy Indiana's regulated equity ratio has remained unchanged at ~53% over this same 14-year period, and the Company is requesting to keep its equity ratio relatively unchanged as part of this rate case, despite the upward trend portrayed in Mr. O'Donnell's Table 5. Mr. Sullivan then addressed the third comparison Mr. O'Donnell makes, involving the equity ratio of Duke Energy Corp. Mr. Sullivan testified it is not appropriate to compare the capital structure of a single-state, regulated utility like Duke Energy Indiana to one of the largest utility holding companies in the U.S. Duke Energy Corp's consolidated capital structure includes that of Duke Energy Indiana and six other regulated utilities, along with a gas-infrastructure business, a substantial portfolio of unregulated renewable energy projects and numerous unregulated minority investments. He stated that Duke Energy Indiana's annual revenues represent ~12% of Duke Energy Corp.'s consolidated revenues. Thus, it is an important subsidiary of Duke Energy Corp., but its regulated capital structure is more applicable to those of other large Duke Energy electric utility subsidiaries, including Duke Energy Carolinas (52%), Duke Energy Progress (53%) and Duke Energy Florida (~53% on an equivalent basis excluding ADIT, customer deposits and ITC).

Mr. Sullivan also emphasized that a 50.0% equity ratio would weaken the Company's credit quality, which in turn will make it more challenging to access capital on competitive terms. He stated that a 50.0% equity ratio represents a 300 basis point reduction to the Company's existing and forecasted ratio of ~53.0%. He testified that lowering the equity ratio by this magnitude would result in higher long-term leverage, higher interest expense, and lower funds-from-operations ("FFO"). The combination of a lower FFO metric and a higher amount of debt would further weaken Duke Energy Indiana's FFO/Debt ratio, and he testified that ratio has come under sharp review by Moody's following the implementation of corporate tax reform. He testified that in its November 2019 Credit Opinion on Duke Energy Indiana, Moody's stated that the rating outlook of Stable reflects "Duke Energy Indiana's credit supportive regulatory environment, including the existence of credit positive infrastructure cost recovery legislation and mechanisms, and adequate financial metrics" and that Duke Energy Indiana's credit profile could weaken and lead to a downgrade if there were "a decline in the credit supportiveness of the utility's regulatory framework." Mr. Sullivan concluded that a material reduction in the equity component of Duke Energy Indiana's regulatory capital structure would weaken both the quantitative (credit metrics) and qualitative (credit supportive regulatory treatment) aspects that Duke Energy Indiana's credit rating agencies and investors consider when evaluating credit quality – and this, in turn, would likely result in higher costs of capital for Duke Energy Indiana and its customers.

Mr. Hevert also responded to Mr. O'Donnell's capital structure recommendation. First, he noted that by relying on the parent capital structure, Mr. O'Donnell assumes all subsidiaries can and should be financed in the same proportions as the parent. He stated that clearly is not the case – companies (including subsidiary companies) are financed in light of the specific risks and funding requirements associated with their individual operations. He noted that the use of the operating subsidiary's actual capital structure – the capital funding the utility plant and equipment that enables utility service – also is consistent with FERC's precedent, under which the FERC prefers to use the applicant's capital structure, where possible. He stated that, in particular, FERC will use the utility operating company's capital structure if it meets three criteria: (1) it issues its own debt without guarantees; (2) it has its own bond rating; and (3) it has a capital structure within the range of capital structures approved by the Commission.

Mr. Hevert also pointed out (as shown on his Exhibit 41-U (RBH)) that the Company's proposed equity ratio is highly consistent with those in place at the operating utilities held within his proxy group. In fact, he stated, the average equity ratio for Mr. O'Donnell's proxy group is 53.63%, 59 basis points above the Company's proposed equity ratio. Among the operating utilities in Mr. Hevert's Updated Proxy Group, the average has been 53.74%, again, quite consistent with the Company's proposal.

iv. **Commission Discussion and Findings**. Addressing Mr. Kollen's ADIT issues first, we find that his proposed adjustments that flow from rate base adjustments need not be made, as we are not accepting the OUCC's rate base adjustments. His additional proposed ADIT adjustments are neither required nor supported by Indiana precedent. Although there appears to be agreement as to ADIT adjustments for MGP, RUS, and charitable contributions, which we will accept, we reject the remainder of his proposed ADIT adjustments.

Turning now to the appropriate equity component to use in the capital structure for setting rates for Petitioner, we find that Mr. O'Donnell's recommendation should be rejected, for several reasons. First, as Mr. Sullivan and Mr. Hevert both pointed out, Mr. O'Donnell's data does not support his proposal. In fact, as Mr. Hevert rebuttal testimony demonstrates, truly comparable data shows that Duke Energy Indiana's equity ratio is reasonable. Further, we find that Mr. O'Donnell's recommendation ignores the financial integrity implications of his proposal. Last, but not least, longstanding Indiana precedent requires the use of a utility's actual, not hypothetical, capital structure when setting rates. Hypothetical capital structures have long been held to be contrary to Indiana law. *See Public Service Comm'n of Ind. v. Ind. Bell Tel. Co.*, 235 Ind. 1, 130, N.E.2d 467 (Ind. 1955). Although we are dealing with a future test period in this case, and are using forecasted capital structures at this point in the process, the Company's proposal will incorporate its actual capital structure, not a forecasted capital structure, when implementing its Step 1 and Step 2 rate increases. Accordingly, we accept Petitioner's proposed capital structure in this case.

b. **Cost of Debt.**

i. **Petitioner's Evidence**. Ms. Douglas explained the calculation of the cost rate assigned to long-term debt in the forecasted test period capital structure. She explained that the summation of the annual interest requirements and amortization of costs related to the issuance of long-term debt, including costs of interest rate hedges, were divided by the net proceeds received from the issuance of the debt. The net proceeds are defined to include unamortized debt premium, discount, issuance expense and unamortized gain or loss on reacquired debt. She stated that for ratemaking purposes, it is appropriate to use net proceeds (i.e., the net investible proceeds from the debt) as the denominator in this equation to give recognition to the fact that the cost rate will be applied to rate base, ensuring that all debt-related costs associated with rate base are covered in the Revenue Requirements calculation.

Mr. Sullivan testified that, as of March 31, 2019, Duke Energy Indiana's weighted average cost of long-term debt is 4.94%. He further testified that Duke Energy Indiana's weighted average cost of long-term debt is forecasted to be 4.88% at the end of 2020 (the end of the test period). He noted that, over the past decade, Duke Energy Indiana has been taking advantage of low interest rates, decreasing its weighted average cost of long-term debt as older bonds are replaced with lower cost debt. Ms. Douglas testified that the Company's proposed 2-step rate increase should reflect the Company's actual cost of debt as of December 31, 2019, for its Step 1 rate increase, and should reflect the actual cost of debt as of December 31, 2020 for its Step 2 rate increase.

ii. **OUCC's and Intervenors' Evidence**. OUCC witness Garrett testified that the Commission should approve a cost of debt of 4.66% for the Company, based on the Company's approach to estimating the rate on upcoming long-term debt issuances, but with considering the reduction in 30-year Treasury bond yields since the Company conducted its analysis. Industrial Group witness Gorman proposed an adjustment to embedded cost of debt for repricing certain new debt issues to 4.62%.

iii. **Petitioner's Rebuttal Evidence**. In its rebuttal testimony, Duke Energy Indiana agreed to update its forecasted cost of debt. Mr. Sullivan testified that in September 2019, Duke Energy Indiana issued $500,000,000 of 30-year First Mortgage Bonds at a coupon of 3.25%, originally estimated at 4.25%. He stated that the expected transaction size was originally $400,000,000 but was upsized to take advantage of the continued low interest rate environment. He further testified that the additional $100,000,000 was issued to refinance two existing callable bonds with a weighted average cost of debt of 4.73%. He observed that this refinancing is an example of how Duke Energy Indiana continues to opportunistically lower the overall cost of debt being charged to customers. He testified that, factoring in the actual 2019 debt replacement activity and the current view of variable and fixed interest rates for 2019 and 2020, the Company's updated forecasted cost of debt for December 31, 2020 is reduced from 4.88% to 4.50% (and Ms. Douglas testified that the current forecasted end of year 2019 debt rate is forecasted to be 4.65%.). Mr. Sullivan and Ms. Douglas both reiterated that rates will ultimately be set to the actual cost of debt as of 12/31/2019 for Step 1 and 12/31/2020 for Step 2.

iv. **Commission Discussion and Findings**. There appears to be no dispute at this point that the Company's forecast of debt for the end of the test period should be updated to 4.50%. However, consistent with our approval of the Company's 2-step rate increase proposal, the Company's proposed 2-step rate increase should reflect the Company's actual cost of debt as of December 31, 2019, for its Step 1 rate increase, and should reflect the actual cost of debt as of December 31, 2020 for its Step 2 rate increase.

c. Cost of Equity.

i. Petitioner's Evidence. Robert Hevert of ScottMadden, Inc. testified on behalf of the Company with respect to cost of equity. Mr. Hevert stated that, based longstanding precedent, the return on equity ("ROE") authorized in this proceeding should provide the Company with the opportunity to earn a return on equity that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. He explained that, to the extent Duke Energy Indiana is provided a reasonable opportunity to earn its market-based cost of equity, neither customers nor shareholders should be disadvantaged. In fact, a return that is adequate to attract capital at reasonable terms enables Duke Energy Indiana to provide safe, reliable electric utility service while maintaining its financial integrity, all to the benefit of both investors and customers.

Mr. Hevert testified that, based on the quantitative and qualitative analyses he performed and discussed in his direct testimony, and considering the Commission's orders in prior rate proceedings, he believes a return on equity ("ROE") in the range of 10.00 percent to 11.00 percent represents the range of equity investors' required ROE for investment in electric utilities like Duke Energy Indiana in the current capital market environment. Within that range, he testified that an ROE of 10.40 percent is reasonable and appropriate. He stated that his recommendation is based on the use of several widely accepted methods and reflects the results of several analyses regarding the effect of Duke Energy Indiana's business risks on its cost of equity.

Mr. Hevert explained that, because all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. Therefore, he relied on three widely accepted approaches to develop his ROE determination: (1) the Constant Growth of the Discounted Cash Flow ("DCF") model; (2) the traditional and Empirical forms of the Capital Asset Pricing Model ("CAPM"); and (3) the Bond Yield Plus Risk Premium approach. According to Mr. Hevert, those analyses indicate the Company's Cost of Equity currently to be in the range of 10.00 percent to 11.00 percent. He further testified that range is corroborated by the Expected Earnings, which results in an average ROE estimate of 10.50 percent and a median ROE estimate of 10.53 percent. Mr. Hevert stated that his analyses recognize that estimating the cost of equity is an empirical, but not entirely mathematical exercise; it relies on both quantitative and qualitative data and analyses, all of which are used to inform the judgment that inevitably must be applied. He emphasized that no single model is more reliable than all others under all market conditions, and all require the use of reasoned judgment in their application, and in interpreting their results.

In addition to these analytical approaches, Mr. Hevert testified that he considered certain other factors, specifically the risks associated with certain aspects of the Company's operations, such as its generation portfolio, its wholesale power operations, its rate mechanisms (including the proposed Revenue Decoupling Mechanism ("RDM")), and the Company's capital expenditure plan. Finally, in addition to the methods noted above, Mr. Hevert stated that he calculated the costs of issuing common stock (that is, "flotation" costs), and considered current and expected capital market and business conditions, including changes in Federal Reserve monetary policy and increases in current and projected government bond yields. He noted that although those factors are very relevant to investors, their effect on the Company's cost of equity cannot be directly quantified. Therefore, although he did not make explicit adjustments to his ROE estimates, he considered those factors in determining where the Company's cost of equity falls within the range of analytical results. In light of those analyses, Mr. Hevert testified that he believes that his recommended range is reasonable and appropriate.

Mr. Hevert explained the need for a proxy group and the rationale supporting his choice of proxy group. He stated that, in this proceeding, the focus is on estimating the cost of equity for Duke Energy Indiana, whose parent is Duke Energy Corporation ("Duke Energy"); because the ROE is a market-based concept and Duke Energy Indiana is not a separate entity with its own stock price, it is necessary to establish a group of companies that are both publicly traded and comparable to the Company in certain fundamental respects to serve as its "proxy" in the ROE estimation process. His selection of a proxy group began with the universe of companies that Value Line classifies as Electric Utilities, and then excluded the following from that universe of electric utilities: companies that do not consistently pay quarterly cash dividends; companies that were not covered by at least two utility industry equity analysts; companies that do not have investment grade senior unsecured bond and/or corporate credit ratings from S&P; companies that were not vertically-integrated, i.e., utilities that own and operate regulated generation, transmission and distribution assets; companies whose regulated operating income over the three most recently reported fiscal years composed less than 60.00 percent of the respective totals for that company; companies whose regulated electric operating income over the three most recently reported fiscal years represented less than 60.00 percent of total regulated operating income; and companies that are currently known to be party to a merger or other significant transaction. Mr. Hevert's screening criteria resulted in a proxy group of 19 companies.

Mr. Hevert testified that the Constant Growth DCF model assumes: (1) earnings, book value, and dividends all grow at the same, constant rate in perpetuity; (2) the dividend payout ratio remains constant; (3) the P/E multiple remains constant in perpetuity; and (4) the discount rate is greater than the expected growth rate and remains constant over time. Mr. Hevert stated that his calculation of the dividend yield was based on the proxy companies' current annualized dividend and average closing stock prices over the 30-, 90-, and 180-trading day periods as of May 31, 2019. He explained that he used three averaging periods to ensure the model's results were not skewed by anomalous events that may affect stock prices on any given trading day, while also being reasonably representative of expected capital market conditions over the long term. To account for periodic growth in dividends, and recognizing that utilities increase their quarterly dividends at different times throughout the year, Mr. Hevert calculated the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield. He testified that this adjustment ensures that the expected dividend yield is, on average, representative of the coming 12-month period, and does not overstate dividends to be paid during that time. Mr. Hevert explained that the Constant Growth DCF model assumes a single growth estimate in perpetuity, and growth in earnings per share represents the appropriate measure of that long-term growth. As support, he cited academic research indicating that estimates of earnings growth are more indicative of long-term investor expectations than are dividend growth estimates, that analysts' forecasts are superior, and that investors rely on analysts' forecasts. Accordingly, Mr. Hevert calculated the DCF results using each of the following growth terms: Zach's consensus long-term earnings growth estimates; First Call consensus long-term earnings growth estimates; and Value Line earnings growth estimates. Mr. Hevert stated that for each proxy company, he calculated mean, mean high, and mean low DCF Model results. Mr. Hevert's Constant Growth DCF results were as follows:

Summary of Discounted Cash Flow Model Results

	Mean	Mean High
30-Day Average	8.93%	9.79%
90-Day Average	8.99%	9.86%
180-Day Average	9.12%	9.99%

Mr. Hevert testified that the Constant Growth DCF model current does not provide a reasonable estimate of the Company's cost of equity. As one example of the need to view DCF results with caution, he noted that one of the model's assumptions is that the Price/Earnings ("P/E") ratio will remain constant in perpetuity, yet utility sector P/E ratios have expanded to the point that they recently have exceeded both their long-term average and the market P/E ratio.

Mr. Hevert explained that he gives less weight to the Constant Growth DCF method because it has recently failed to provide reliable ROE estimates. He noted that, as a practical matter, mean Constant Growth DCF results are below a highly observable and relevant benchmark – returns actually authorized for electric utilities. Specifically, he testified that since 2014, the model has produced results (i.e., mean results) consistently and meaningfully below authorized returns. He stated that data suggests state regulatory commissions have recognized the model's results are not necessarily reliable estimates of the cost of equity, and that other methods should be given meaningful weight in determining the ROE. He noted that the FERC recently addressed its longstanding focus on the DCF method. In a November 2018 Order, FERC found that "in light of current investor behavior and capital market conditions, relying on the DCF methodology alone will not produce a just and reasonable ROE."[7] And in a October 2018 Order, FERC found that although it "previously relied solely on the DCF model to produce the evidentiary zone of reasonableness…", it is "…concerned that relying on that methodology alone will not produce just and reasonable results."[8] Mr. Hevert noted that state commissions have reached similar conclusions about the importance of relying on multiple cost of equity methodologies. For example, the South Carolina Public Service Commission determined that "it is appropriate and reasonable to consider a range of estimates under various methodologies in order to more accurately estimate [South Carolina Electric & Gas's] cost of equity," and relying on a single analytical method is "inconsistent with decisions reached by regulatory commissions over the past several years and departs from the normal practice of estimating the Cost of Equity for utilities."[9] As another example, in its July 2017 Order Accepting Stipulation in which it authorized a 9.90 percent ROE for Duke Energy Carolinas, the North Carolina Utilities Commission noted it "carefully evaluated the DCF analysis recommendations" of the ROE witnesses (which ranged

[7] Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at para. 34.
[8] Docket No. EL11-66-001, *et al.*, *Order Directing Briefs* 165 FERC ¶ 61,030 (October 16, 2018) at para. 30. FERC explained, it is important to understand "how investors analyze and compare their investment opportunities." FERC also explained that, although certain investors may give some weight to the DCF approach, other investors "place greater weight on one or more of the other methods…." Those methods include the CAPM and the Risk Premium method, which Mr. Hevert applied in this proceeding.
[9] Public Service Commission of South Carolina, Docket Nos. 2017-207-E, 2017-305-E, and 2017-370-E, Order No. 2018-804, Order Addressing South Carolina Electric & Gas Nuclear Dockets, at 89-90. [clarification added]

from 8.45 percent to 8.80 percent) and determined that "all of these DCF analyses in the current market produce unrealistically low results."[10]

Mr. Hevert explained that the Constant Growth DCF model's underlying structure and assumptions are simply not compatible with the recent capital market and economic environment. He stated that can most easily be seen by recognizing that the model's fundamental structure requires the assumption of constancy in perpetuity. It assumes there will be no change in growth rates, dividend payout ratios, Price/Earnings ratios, Market/Book ratios, or in the economic and market conditions that support those variables. Equally important, he stated, the model assumes the cost of equity estimated today will remain unchanged, also in perpetuity; that is, the model requires that the cost of equity estimate produced today will be the same forward-looking return equity investors will require every day in the future, in perpetuity. He explained that, in contrast, federal monetary policy has had a significant, intentional effect on capital markets, dampening both interest rates and volatility, raising the issue of whether it is reasonable to assume the market conditions created by those policies will stay in place over the long run. For example, he pointed out that the Federal Reserve is continuing to "normalize" its monetary policy such that the conditions supporting current ROE estimates will not persist in the long-run. Regardless of its eventual disposition, neither the Federal Reserve's unconventional monetary policy initiatives, nor the capital market conditions they supported, will remain in place in perpetuity, as the Constant Growth DCF model requires. On that basis alone, he stated that it is necessary to be cautious about the weight given the DCF method. He also explained that the DCF model assumes investors use its fundamental structure to find the "intrinsic" value of stock; that is, the price they are willing to pay. In practice, however, he noted that investors also consider relative valuation multiples – Price/Earnings, Market/Book, Enterprise Value/EBITDA [11] – in their buying and selling decisions. They do so because no single financial model produces the most accurate measure of fundamental value, or the most reliable estimate of the cost of equity, at all times.

Mr. Hevert explained that whereas DCF models focus on expected cash flows, Risk Premium-based models focus on the additional return that investors require for taking on greater risk. Mr. Hevert testified that the CAPM defines the Cost of Equity as the sum of the "risk-free" rate, and a premium to reflect the additional risk associated with equity investments. The "risk-free" rate is the yield on a security viewed as having no default risk, such as long-term Treasury bonds. The risk-free rate essentially sets the baseline of the CAPM. That is, an investor would expect a higher return than the risk-free rate to purchase an asset that carries risk. The difference between that higher return (i.e., the required return) and the risk-free rate is the risk premium. The risk premium is necessary to compensate investors for the non-diversifiable or systematic risk of the security. Thus, he testified, there are four forward-looking components in a CAPM analysis: (1) the required market ROE for a security, which is comprised of (2) the risk-free rate of return, plus the required risk premium -- i.e., (3) the return on the market a whole minus the risk-free return, adjusted by (4) the non-diversifiable risk of that security, which is the Beta coefficient. The Beta coefficient is a measure of the subject company's risk relative to the overall market, i.e., the "non-diversifiable" risk. Beta coefficients reflect two important aspects of stock price movements:

[10] State of North Carolina Utilities Commission, Docket No. E-7, Sub 1146, *In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, July 25, 2017, at 62.

[11] Earnings Before Interest, Taxes, Depreciation, and Amortization.

(1) the variability or volatility of the subject company's returns relative to the market; and (2) the correlation of the subject company's returns to the market's returns.

Mr. Hevert used two different measures of the risk-free rate in his CAPM analysis, to reflect the fact that utility equity is a long-term investment: (1) the current 30-day average yield on 30-year Treasury bonds (2.85%); and (2) the near-term projected 30-year Treasury yield (3.03%). Mr. Hevert stated that he relied on the 30-year Treasury yield because it best matches the life of the underlying investment – electric utility securities are typically long duration investments.

Mr. Hevert estimated the market required return by calculating the market capitalization weighted average ROE based on the Constant Growth DCF model, relying on data from Bloomberg and Value Line for each proxy company. He then subtracted the 30-year Treasury yield to arrive at the risk premium estimate. He then considered the adjusted Beta coefficients reported by both Value Line and Bloomberg, and arrived at the following CAPM results:

CAPM	**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.85%)	8.09%	8.59%
Near Term Projected 30-Year Treasury (3.03%)	8.27%	8.77%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.85%)	9.32%	9.93%
Near Term Projected 30-Year Treasury (3.03%)	9.50%	10.11%

Because the correlation between the proxy group companies and the S&P 500 has declined since 2010, while the relative risk has increased, Mr. Hevert testified that the CAPM may not adequately reflect the expected systematic risk, and therefore, the returns required by investors in low-Beta coefficient companies. Accordingly, he also considered the Empirical CAPM ("ECAPM") approach, which is a variant of the CAPM approach.

Mr. Hevert explained that the ECAPM adjusts for the CAPM's tendency to under-estimate returns for companies that (like utilities) have Beta coefficients less than one, and over-estimate returns for relatively high-Beta coefficient stocks. He stated that the ECAPM recognizes the results of academic research indicating that the risk-return relationship is different (flatter) than estimated by the CAPM, and the CAPM understates the alpha (the constant return term). Quoting Roger Morin, Mr. Hevert stated: "With few exceptions, the empirical studies agree that . . . low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. . . ."[12] Responding to arguments that the ECAPM is inconsistent with the use of adjusted betas, he further quoted Dr. Morin:

[12] Roger A. Morin, *New Regulatory Finance* 175, 190 (2006).

> Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. . . . [T]he ECAPM is a return [] adjustment and not a beta [] adjustment. Both adjustments are necessary.[13]

Mr. Hevert testified that, as with his CAPM analysis, his application of the ECAPM used the Market DCF-derived market risk premium estimate, the current yield on 30-year Treasury securities as the risk-free rate, and two estimates of the Beta coefficient. The results of his ECAPM analyses are as follows:

Empirical CAPM	**Bloomberg Derived Market Risk Premium**	**Value Line Derived Market Risk Premium**
Average Bloomberg Beta Coefficient		
Current 30-Year Treasury (2.85%)	9.53%	10.17%
Near Term Projected 30-Year Treasury (3.03%)	9.71%	10.35%
Average Value Line Beta Coefficient		
Current 30-Year Treasury (2.85%)	10.45%	11.17%
Near Term Projected 30-Year Treasury (3.03%)	10.63%	11.35%

The Bond Yield Plus Risk Premium approach is based on the basic financial principle that equity investors bear the risk associated with ownership and therefore require a premium over the return they would have earned as a bondholder. That is, because returns to equity holders are riskier than returns to bondholders, equity investors must be compensated for bearing that additional risk (that difference often is referred to as the "Equity Risk Premium"). In performing his Bond Yield Plus Risk Premium analysis, Mr. Hevert first defined the Equity Risk Premium as the difference between the authorized ROE and the then-prevailing level of the long-term (i.e., 30-year) Treasury yield. He stated that he gathered data for the ROEs authorized in 1,593 electric utility rate proceedings between January 1980 and May 31, 2019. In addition to the ROE, he also calculated the average period between the filing of the case and the date of the final order (the "lag period"). To calculate the prevailing level of interest rates during the pendency of the proceedings, he calculated the average 30-year Treasury yield over the average lag period (approximately 200 days). Mr. Hevert also testified that he analyzed the relationship between interest rates and the equity risk premium, using regression analysis. He noted that his analysis indicated that, over time, there has been a statistically significant, negative (inverse) relationship between the 30-year Treasury yield and the Equity Risk Premium. Consequently, he testified, simply applying the long-term average Equity Risk Premium would significantly understate the cost of equity and would

[13] *Id.* At 191.

produce results well below any reasonable estimate. Based on his regression analyses, however, Mr. Hevert concluded that the implied ROE is between 9.91 percent and 10.06 percent.

Bond Yield Plus Risk Premium Approach	
Current 30-Year Treasury (2.85%)	9.91%
Near Term Projected 30-Year Treasury (3.03%)	9.92%
Long-Term Projected 30-Year Treasury (3.70%)	10.06%

Mr. Hevert explained the Expected Earnings analysis is based on the principle of opportunity costs. Because investors may invest in, and earn returns on, alternative investments of similar risk, those rates of return can provide a useful benchmark in determining the appropriate rate of return for a firm; investors are able to directly compare returns from investments of similar risk. Mr. Hevert testified that Value Line also provides projected returns on book equity. Because the Cost of Equity is forward-looking, Mr. Hevert relied solely on Value Line's forward-looking projections in the Expected Earnings analysis. Specifically, Mr. Hevert relied on Value Line's projected return on common equity for the period 2022-2024, and adjusted those projected returns to account for the fact that they reflect common shares outstanding at the end of the period, rather than the average shares outstanding over the course of the year. Mr. Hevert stated that the Expected Earnings analysis resulted in an average value of 10.50 percent and a median value of 10.53 percent.

Mr. Hevert next discussed flotation costs. He explained that flotation costs are the costs associated with the sale of new issues of common stock. These include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance. He stated that flotation costs are part of capital costs; like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the great majority of flotation costs are incurred prior to the test year, but remain part of the cost structure during the test year and beyond. He stated that although the Company is a wholly owned subsidiary of Duke Energy, it is appropriate to consider flotation costs because wholly owned subsidiaries receive equity capital from their parents and provide returns on the capital that roll up to the parent, which is designated to attract and raise capital based on the returns of those subsidiaries. He testified that denying recovery of issuance costs associated with the capital that is invested in the subsidiaries ultimately, would penalize the investors that fund the utility operations, and would inhibit the utility's ability to obtain new equity capital at a reasonable cost. He emphasized that this is important for companies such as Duke Energy Indiana that are planning continued capital expenditures in the near term, and for which access to capital to fund such required expenditures will be critical. He also noted that the need to reimburse investors for equity issuance costs is recognized by the academic and financial communities in the same spirit that investors are reimbursed for the costs of issuing debt. In order to estimate the size of the effect of flotation costs on investor returns, Mr. Hevert modified the DCF calculation to provide a dividend yield that would reimburse investors for issuance costs. The estimate of flotation costs recognizes the costs of issuing equity that were incurred by Duke Energy and the proxy companies in their most recent two issuances. He concluded that an adjustment of 0.08 percent (i.e., eight basis points) reasonably represents flotation costs for the Company. However, Mr. Hevert stated that he is not proposing to adjust his recommended ROE by eight basis points to reflect the flotation costs; rather, he considered the effect of flotation costs, in addition to the Company's other business risks in determining where the Company's ROE falls within the range of results.

Mr. Hevert testified that the analytical model results for the proxy group by themselves do not necessarily provide an appropriate estimate of Duke Energy Indiana's cost of equity. In his view, there are additional factors that must be taken into consideration when determining where Duke Energy Indiana's cost of equity falls within the range of results. These factors include: the risks associated with certain aspects of the Company's generation portfolio; the price volatility associated with the Company's wholesale power sales within the MISO market; the Company's rate mechanisms currently in place, as well as its proposed RDM; and the Company's capital expenditure plan.

With regard to the risks associated with the Company's generation portfolio, Mr. Hevert noted that Duke Energy Indiana's operations are dependent on coal-fired generation, and Duke Energy Indiana and its investors face (and consider) the risk that environmental regulations will require them to invest additional capital or face closure or curtailment of generating capacity. These risks are compounded in the current regulatory environment as a result of the uncertainty investors, utilities, and the economy as a whole face in light of evolving environmental regulations regarding greenhouse gas emissions and climate change in general. As support, he cited the Clean Power Plan, recently repealed by the U.S. Environmental Protection Agency ("EPA") and replaced with the Affordable Clean Energy ("ACE") rule; other existing and evolving environmental regulations, such as periodic updates to National Ambient Air Quality Standards, implementation of the 316(b) cooling water intake structures rule, and implementation of revisions to the Steam Electric Effluent Limitations guidelines; and continuing legal challenges to many regulations, such as the Mercury and Air Toxics Standards ("MATS") rule. He added that, with respect to generation portfolio risks, in general, capital intensive generation assets such as coal-fired generation facilities are subject to certain risks including the recovery of the investors' capital in the event of a change in market structure or a plant failure, and the recovery of replacement power and repair costs in the event of extended or unplanned outage.

With regard to MISO market risks, Mr. Hevert noted, among other things, the MISO markets' volatility, resulting in revenue volatility; and declines in wholesale market prices, occasionally to negative levels. With regard to regulatory mechanisms, Mr. Hevert acknowledged the various regulatory mechanisms the Company has in place, as well as the Company's proposal in this case for a revenue decoupling mechanism. He explained that such mechanisms have become increasingly common, due to the growing cost of maintaining system reliability, coupled with flat or declining sales volume brought on by energy efficiency. He testified that adjustment mechanisms to recover purchased power expenses, energy efficiency and demand-side program costs, new plant investment, and other expenses are common.[14] In addition, he noted that full or partial decoupling mechanisms have been implemented by electric utilities in a majority of state jurisdictions.[15] Further, he noted that cost recovery mechanisms and decoupling mechanisms are common among the proxy group companies.

Mr. Hevert explained that, under Modern Portfolio Theory (and the CAPM), an investor would not be indifferent to a reduction in expected ROE in return for the implementation of rate structures, unless those structures specifically reduce non-diversifiable risk. That is, any reduction

---

[14] *See*, Petitioner's Exhibit 11-I.
[15] *See, e.g.*, *Adjustment Clauses: A State-by-State Overview*, Regulatory Research Associates Regulatory Focus, September 28, 2018, and American Council for an Energy-Efficient Economy "Utility Business Model State and Local Policy Database", accessed November 7, 2018, https://database.aceee.org/state/utility-business-model.

in the cost of equity depends on the type of risk that is reduced; if the risk assumed to be mitigated by the rate structures is diversifiable, there would be no reduction in the cost of equity even if total risk (diversifiable plus non-diversifiable risk) has been reduced. If, however, rate structures mitigate increased systematic risk associated with the factors that drove their implementation in the first place, there likewise would be no effect on the cost of equity.

With respect to decoupling mechanisms in particular, Mr. Hevert testified about studies that examined the effect of revenue decoupling on the cost of capital for electric utilities. The first such study (and update) which found no statistically significant link between the cost of capital and revenue decoupling structures, [16] while a second study found decoupling to have no statistically significant effect on investor perceived risk, and the cost of equity.[17]

With regard to Duke Energy Indiana's capital expenditure plans, Mr. Hevert testified that, based on Duke Energy's March 2019 investor presentation, Duke Energy Indiana plans to deploy approximately $3.95 billion in capital over the period 2019-2023. That amount includes expenditures in generation, transmission, and distribution facilities and to maintain safe, sufficient, and reliable service. Mr. Hevert testified that Duke Energy Indiana's capital expenditure plan is larger than its allowed recovery under its capital trackers. Although the Company should be able to partially mitigate the cash flow dilution associated with those investments, the recovery mechanisms should be viewed as credit supportive, rather than credit enhancing, and from that perspective, the mechanisms would not reduce the Company's cost of equity.

With respect to the capital market environment, Mr. Hevert discussed the increased volatility in the capital markets, noting that the increase in volatility is not surprising as market participants reassess the Federal Reserve's long-term objective of monetary policy normalization, and the increasing risks associated with federal trade policy initiatives. He noted the relationship between market volatility and interest rates; significant and abrupt increases in volatility tend to be associated with declines in Treasury yields. He explained that such a relationship makes intuitive sense; as investors see increasing risk their objectives may shift principally to capital preservation (that is, avoiding a capital loss). He testified that, in those instances, the fall in yields does not reflect a reduction in required returns, it reflects an increase in risk aversion and, therefore, an increase in required equity returns. Further, he noted that market volatility is expected to increase from its current levels. He explained that one means of assessing market expectations regarding the future level of volatility is to review Cboe's "Term Structure of Volatility." He stated that Cboe's term structure data is upward sloping, indicating market expectations of increasing volatility. Mr. Hevert also noted that recent declines in treasury yields have been associated with increases in market volatility. He stated that the recent, sudden decline in interest appears to be related to the increase in equity market volatility, which may be event-driven rather than a

[16] The Brattle Group, *The Impact of Revenue Decoupling on the Cost of Capital for Electric Utilities: An Empirical Investigation*, Prepared for the Energy Foundation, March 20, 2014. Michael J. Vilbert, Joseph B. Wharton, Shirley Zhang and James Hall, *Effect on the Cost of Capital of Innovative Ratemaking that Relaxes the Linkage between Revenue and kWh Sales – An Updated Empirical Investigation*, November 2016. Also available at http://files.brattle.com/files/5711_effect_on_the_cost_of_capital_of_ratemaking_that_relaxes_the_linkage_between_revenue_and_kwh_sales.pdf.

[17] Dr. Richard A. Michelfelder, Pauline M. Ahern, Dylan W. D'Ascendis, *Decoupling impact and public utility conservation investment*, Energy Policy 130 (2019) 311-319.

fundamental change. Because the methods used to estimate the Cost of Equity are forward-looking, Mr. Hevert testified it is important to consider those distinctions in assessing model results.

Mr. Hevert commented on the fundamental relationship between Treasury yields and utility dividend yields changed after the 2008/2009 financial crisis. He testified that even though the "yield spread"[18] became inverted after the financial crisis, it has not been static. That is, as Treasury yields fell in response to central bank policies, dividend yields did not fall to the same degree; the yield spread widened. That data suggests that, although utility prices are sensitive to long-term Treasury yields, the relationship is not unbounded. Further, he testified that utility-specific stock price data supports the conclusion that utility stock prices are sensitive to changes in interest rates, but only to a degree. The "reach for yield" that sometimes occurs when interest rates fall has a limit; investors will not accept the incremental risk of capital losses when utility valuation levels become "stretched". That also may be the case when investors see interest rates reacting to market volatility that is event-driven, rather than a fundamental change in the capital market environment or investor risk tolerances. Mr. Hevert concluded his discussion of capital market conditions by observing that the current market environment is one in which changes in interest rates likely are associated with events, more than they are a function of fundamental economic conditions; further, utility valuations have a limit, even when investors look to them for an alternate source of income as interest rates fall.

In concluding his testimony, Mr. Hevert testified that a balanced approach to estimating a utility's cost of equity is to consider the relative strengths and weaknesses of multiple methods, and give the appropriate weight to their results. Based on his analysis and utilizing that approach, Mr. Hevert reiterated his view that an ROE in the range of 10.00 percent to 11.00 percent represents the range of equity investors' required ROE for investment in integrated electric utilities in the current market environment; and an ROE of 10.40 percent represents the cost of equity for Duke Energy Indiana.

Mr. Hevert testified that in developing his recommendation, he recognized that the low and high ends of the range of results (set by the low end of the range of Constant Growth DCF model results, and the high end of the range of Empirical CAPM results, respectively) are not likely to be reasonable estimates of the Company's cost of equity. He explained that, in large measure, that is the case because those results are far removed from the returns recently authorized in other jurisdictions and, in the case of DCF-based methods, fail to adequately reflect evolving capital market conditions. He explained that because Risk Premium-based methods directly reflect measures of capital market risk, they are more likely than other approaches (such as the Constant Growth DCF method) to provide reliable estimates of the cost of equity during periods of market instability.

Mr. Hevert also stated that his ROE conclusion considers the cost associated with issuing common stock and the current capital market environment, as well as Duke Energy Indiana's risk profile relative to the proxy group analytical results with respect to the risks associated with certain aspects of the Company's generation portfolio, the Company's wholesale power sales within MISO, the Company's current and proposed rate mechanisms, and the Company's capital expenditure plan. In light of these factors, Mr. Hevert testified that it is appropriate to establish an

[18] Defined here as dividend yields less Treasury yields.

ROE that is above the proxy group mean results. As such, an ROE of 10.40 percent reasonably represents the return required to invest in a company with a risk profile comparable to Duke Energy Indiana.

ii. OUCC's Evidence. Mr. Garrett testified that, pursuant to the legal and technical standards, the awarded ROE should be based on, or reflective of, the utility's cost of equity. He testified that the Company's estimated cost of equity is approximately 6.3%, based on his analyses using the DCF and CAPM methodologies. He noted, however, these legal standards do not mandate the awarded ROE be set exactly equal to the cost of equity. Rather, he stated, in *Federal Power Commission v. Hope Natural Gas Co., the U.S. Supreme Court* found that, although the awarded return should be based on a utility's cost of capital, it is also indicated that the "end result" should be just and reasonable. Mr. Garrett testified that if the Commission were to award a return equal to the Company's estimated cost of equity of 6.3%, it would be accurate from a technical standpoint. He recommended, however, the Commission authorize an ROE that is remarkably higher than the Company's actual cost of equity in this case. Specifically, he recommends an authorized ROE of 9.0%, which he stated is within a reasonable range of 8.75% – 9.25%. He noted that the ratemaking concept of "gradualism," though usually applied from the customer's standpoint to minimize rate shock, could also be applied to shareholders. He further noted that an authorized return as low as 6.3% in any current rate proceeding would represent a substantial change from the "status quo." He testified that if the Commission were to make a significant, sudden change in the authorized ROE anticipated by regulatory stakeholders, it could have the undesirable effect of notably increasing the Company's risk profile and would arguably be at odds with the *Hope* Court's "end result" doctrine. He opined that an authorized ROE of 9.0% represents a good balance between the Supreme Court's indications that awarded ROEs should be based on cost, while also recognizing that the end result must be reasonable under the circumstances. He further opined that an authorized ROE of 9.0% also represents a gradual move toward the Company's market-based cost of equity, and it would be fair to the Company's shareholders because 9.0% is over 250 basis points above the Company's market-based cost of equity.

Mr. Garrett testified that he chose to use the same proxy group used by Mr. Hevert. He stated that there could be reasonable arguments made for the inclusion or exclusion of a particular company in a proxy group; however, he noted the cost of equity results are influenced far more by the underlying assumptions and inputs to the various financial models than the composition of the proxy groups.

Mr. Garrett chose to use the Quarterly Approximation DCF Model to estimate the Company's cost of equity capital. To determine the stock price input to the DCF Model, he used a 30-day average of stock prices for each company in the proxy group, under the rationale that using a short-term average of stock prices for the current stock price input adheres to market efficient principles while avoiding any irregularities that may arise from using a single current stock price. The stock prices he used were based on 30-day averages of adjusted closing stock prices for each company in the proxy group. The dividend term in the Quarterly Approximation DCF Model is the current quarterly dividend per share. Mr. Garrett testified that the Quarterly Approximation DCF Model results in the highest cost of equity relative to other DCF Models, all else held constant, due to the quarterly compounding of dividends inherent in the model. Mr. Garrett stated that the differences between his DCF Model and Mr. Hevert's DCF Model are primarily driven by differences in growth rate estimates, rather than by stock price and dividend inputs for each proxy company.

Mr. Garrett stated that the most critical input in the DCF Model is the growth rate, and unlike the stock price and dividend inputs, the growth rate input must be estimated. The DCF model he used in this case is based on the constant growth valuation model. Under this model, a stock is valued by the present value of its future cash flows in the form of dividends. Before future cash flows are discounted by the cost of equity, however, they must be "grown" into the future by a long-term growth rate. Thus, as stated above, one of the inherent assumptions of this model is that these cash flows in the form of dividends grow at a constant rate forever. Mr. Garrett stated that once a firm is in the maturity stage, it is not necessary to consider higher short-term growth metrics in multi-stage DCF Models; rather, it is sufficient to analyze the cost of equity using a stable growth DCF Model with one terminal, long-term growth rate. He testified that because utilities are in their maturity stage, their real growth opportunities are primarily limited to the population growth within their defined service territories, which is usually less than 2%. He noted that in Duke Energy Indiana's 2018 IRP, the Company acknowledged a very low load growth projection of 0.5% over the 20-year planning period. He noted that this figure is starkly at odds with Mr. Hevert's annual earnings growth projections for the proxy group, which are as high as 10% per year over the long term.

Additionally, Mr. Garrett stated, a fundamental concept in finance is that no firm can grow forever at a rate higher than the growth rate of the economy in which it operates. Thus, the terminal growth rate used in the DCF Model should not exceed the aggregate economic growth rate. This is especially true, he stated, when the DCF Model is conducted on public utilities because these firms have defined service territories. In fact, he offered, it is reasonable to assume that a regulated utility would grow at a rate that is less than the U.S. economic growth rate. He testified that according to the Congressional Budget Office's Budget Outlook, the long-term forecast for nominal U.S. GDP growth is 3.9%, which includes an inflation rate of 2%. For mature companies in mature industries, such as utility companies, he opined, the terminal growth rate will likely fall between the expected rate of inflation and the expected rate of nominal GDP growth. Thus, he concluded that the Company's terminal growth rate is realistically between 2% and 4%.

He added that any thorough assessment of company growth should be based upon a "qualitative" analysis. Such an analysis would consider specific strategies that company management will implement to achieve a sustainable growth in earnings. While qualitative growth analysis is important regardless of the entity being analyzed, it is especially important in the context of utility ratemaking. This is because the rate base rate of return model inherently possesses two factors that can contribute to distorted views of utility growth when considered exclusively from a quantitative perspective: (1) rate base and (2) the awarded ROE.

Mr. Garrett stated that he considered various qualitative determinants of growth for the Company, along with the maximum allowed growth rate under basic principles of finance and economics. For the long-term growth rate in his DCF model, he selected 3.90%, which means his model assumes that the Company's qualitative growth in earnings will match the nominal growth rate of the entire U.S. economy over the long run.

Based on Mr. Garrett's inputs to the Quarterly Approximation DCF Model discussed, he estimated a DCF cost of equity estimate for the Company of 6.9%, which he characterized as likely being at the higher end of the reasonable range due to his relatively high estimate for the long-term growth rate.

Mr. Garrett also offered several critiques of Mr. Hevert's DCF analyses, summarized as follows:

- The results of Mr. Hevert's DCF Model are overstated primarily because of a fundamental error regarding his growth rate inputs. Mr. Hevert used long-term growth rates in his proxy group as high as 10%, which is about three times as high as projected, long-term nominal U.S. GDP growth (about 4.0%). This means Mr. Hevert's growth rate assumption violates the basic principle that no company can grow at a greater rate than the economy in which it operates over the long-term, especially a regulated utility company with a defined service territory. Further, Mr. Hevert used short-term, quantitative growth estimates published by analysts. These analysts' estimates are inappropriate to use in the DCF Model as long-term growth rates because they are estimates for shorter-term growth.

- Mr. Hevert inappropriately considered flotation costs when making his awarded return recommendation. Flotation costs are not actual "out-of-pocket" costs; the Company has not experienced any out-of-pocket costs for flotation. Instead, underwriters are compensated through an "underwriting spread " -- the difference between the price at which the underwriter purchases the shares from the firm, and the price at which the underwriter sells the shares to investors. Furthermore, Duke Energy Indiana is not a publicly traded company, which means it does not issue securities to the public and thus would have no need to retain an underwriter. Accordingly, the Company has not experienced any out-of-pocket flotation costs. Moreover, the market already accounts for flotation costs.

Mr. Garrett next discussed his CAPM analysis. He testified that he considered a 30-day average of daily Treasury yield curve rates on 30-year Treasury bonds in his risk-free rate estimate, which resulted in a risk-free rate of 2.18%. Further, he testified that he used betas recently published by Value Line Investment Survey. He noted that the beta for each proxy company is less than 1.0, and the average beta for the proxy group is only 0.57.

Next, Mr. Garrett testified about the Equity Risk Premium ("ERP"). He testified that he relied primarily on the ERP reported in expert surveys and the implied ERP method rather than the calculation of a historical average. He stated that, after collecting data for the index value, operating earnings, dividends, and buybacks for the S&P 500 over the past six years, he calculated the dividend yield, buyback yield, and gross cash yield for each year. He also calculated the compound annual growth rate (g) from operating earnings. He used these inputs, along with the risk-free rate and current value of the index to calculate a current expected return on the entire market of 8.19%. He then subtracted the risk-free rate to arrive at the implied equity risk premium of 6.0%. For the final ERP estimate he used in his CAPM analysis, he considered the results of the ERP surveys, the implied ERP calculations discussed above, and the estimated ERP reported by Duff & Phelps. Mr. Garrett stated that he conservatively selected the highest ERP estimate of 6.0%

to use in his CAPM analysis. Using the inputs for the risk-free rate, beta coefficient, and equity risk premium discussed above, he estimated that the Company's CAPM cost of equity is 5.6%.

Mr. Garrett also critiqued certain aspects of Mr. Hevert's CAPM analysis. He stated that the primary problem with Mr. Hevert's CAPM cost of equity result stems primarily from his estimate of the ERP, which he estimates as high as 12%. Mr. Garrett stated that the highest ERP found from my research and analysis is only 6.0%.

Regarding Mr. Hevert's other Risk Premium analyses, Mr. Garrett testified that he disagreed with the premise of Mr. Hevert's "bond yield plus risk premium" analysis, because Mr. Hevert looked at awarded ROEs dating back to 1980. He stated that not only is this contra to Mr. Hevert's claim that the cost of equity is a "forward-looking" concept, but it also suffers from the fact that awarded ROEs are consistently higher than market-based cost of equity. Further, he stated that the risk premium analysis offered by Mr. Hevert is completely unnecessary when we already have a real risk premium model to use: the CAPM. The CAPM itself is a "risk premium" model; it takes the bare minimum return any investor would require for buying a stock (the risk-free rate), then adds a premium to compensate the investor for the extra risk he or she assumes by buying a stock rather than a riskless U.S. Treasury security.

Mr. Garrett also took issue with Mr. Hevert's consideration of various firm-specific risk factors. He stated that the Commission should not consider these firm-specific business risk factors in making their decision on a fair awarded ROE in this case, because they are not unique to Duke Energy Indiana. He argued that that market risk, or "systematic risk," is the only type of risk for which investors expect a return for bearing, and investors do not require additional compensation for assuming these firm-specific business risk.

He concluded that the cost of equity indicated by the results of the DCF Model and the CAPM is about 6.3%. He added that the average market cost of equity from sources such as consulting expert surveys, etc., is only 7.5%, which he stated supports his estimated 6.3% ROE. He recommended the IURC award the Company with a 9.0% ROE, which is the midpoint in a reasonable range of 8.75% – 9.25%. He stated that although Duke Energy Indiana's cost of equity is much lower than 9.0% by any objective measure, the Commission should gradually reduce the Company's awarded return towards market-based levels, consistent with the *Hope* Court's end result doctrine

iii. **Industrial Group's Evidence.** Mr. Gorman testified on behalf of the Industrial Group with respect to cost of equity. Mr. Gorman recommended Duke Energy Indiana's current market cost of equity to be no higher than 9.0%. He stated that a return on common equity of 9.0% is the midpoint of his estimated range of 8.50% to 9.30%. His recommended ROE range was based on the following analytical models: Constant Growth DCF, Multi-Stage Growth DCF, CAPM. With one exception, Mr. Gorman utilized the same proxy group as did Mr. Hevert. Mr. Gorman further testified that his recommended return on equity estimates reflect observable market evidence, the impact of Federal Reserve policies on current and expected long-term capital market costs, an assessment of the current risk premium built into current market securities, and a general assessment of the current investment risk characteristics of the electric utility industry and the market's demand for utility securities.

Mr. Gorman's stated that his Constant Growth DCF analysis produced average and median constant growth DCF returns for the proxy group of 8.61% and 8.51%, respectively. He testified that the constant growth DCF analysis for the proxy group is based on a group average long-term sustainable growth rate of 5.59%, higher than his estimate of a maximum long-term sustainable growth rate of 4.00%. Consequently, he stated his belief that the constant growth DCF analysis produces a reasonable high-end return estimate.

Mr. Gorman next discussed the results of his Sustainable Growth DCF analysis. He testified that a sustainable growth rate is based on the percentage of the utility's earnings that is retained and reinvested in utility plant and equipment. He stated that these reinvested earnings increase the earnings base (rate base); earnings grow when plant funded by reinvested earnings is put into service and the utility is allowed to earn its authorized return on such additional rate base investment. He testified that the proxy group's dividend payout ratios and earnings retention ratios can be used to develop a sustainable long-term earnings retention growth rate, to help gauge whether analysts' current three- to five-year growth rate projections can be sustained over an indefinite period of time. He stated that the average sustainable growth rate for the proxy group using this model is 5.08%. Mr. Gorman's DCF estimate based on these sustainable growth rates produces average and median DCF results for the 13-week period of 8.09% and 7.97%, respectively.

Mr. Gorman next discussed his Multi-Stage Growth DCF analysis, which he performed to reflect this outlook of changing growth expectations. He explained that the Multi-Stage Growth DCF model reflects the possibility of non-constant growth for a company over time. He testified that the results of his Multi-Stage Growth DCF analysis produced average and median DCF returns on equity for the proxy group using the 13-week average stock price of 7.28% and 7.15%, respectively.

Mr. Gorman concluded that his DCF studies support a return on equity of 8.60%. He stated that his recommended point estimate is primarily based on his Constant Growth DCF estimates, but also considers the results of his other DCF models.

Next, Mr. Gorman discussed the results of his Bond Yield Plus Risk Premium analysis. He testified that his analysis indicated a return in the range of 8.6% to 8.7%. He further testified that relying on the highest estimates produces a return on equity in the range of 9.27% to 9.39%, with an approximate midpoint of 9.30%. He stated that, to be conservative, recognizing the significant decline most recently of capital market costs, he recommended a return on equity of 9.3% based on the risk premium methodology.

Mr. Gorman next discussed the results of his CAPM analysis. He stated that based on his low market risk premium of 6.0% and his high market risk premium of 8.5%, a risk-free rate of 2.5%, and a historical average utility beta of 0.70, his CAPM analysis produces a return in the range of 6.71% to 8.46%. Further, based on his assessment of risk premiums in the market, he placed primary reliance on his high-end CAPM return estimates. He stated that this produces a recommended CAPM return estimate of 8.5%.

Mr. Gorman summarized his cost of equity analyses under the various models as follows:

TABLE 18

Return on Common Equity Summary

Description	Results
DCF	8.60%
Risk Premium	9.30%
CAPM	8.50%

Mr. Gorman testified that his return on equity estimates reflect observable market evidence, the impact of Federal Reserve policies on current and expected long-term capital market costs, an assessment of the current risk premium built into current market securities, and a general assessment of the current investment risk characteristics of the electric utility industry and the market's demand for utility securities. Mr. Gorman stated that observable market evidence demonstrates that capital market costs are near historically low levels, and while authorized returns on equity have fallen to the mid-9% range, utilities continue to have access to large amounts of external capital even as they are funding large capital expenditure programs. Further, he stated that utilities' investment-grade credit ratings are stable and have improved, due in part to supportive regulatory treatment. Mr. Gorman also testified that the industry's stock performance data from 2004 through June 2019 shows that the electric and gas utility indexes have followed the market through downturns and recoveries; however, utility investments have been less volatile during extreme market downturns. He stated that this more stable price performance for utilities supports his conclusion that market participants regard utility stock investments as moderate- to low-risk investments. Further, he stated that while utility stocks have not exhibited the same volatility as the S&P 500, stock prices have remained strong, relative to the market in general, and support the utilities' access to equity capital markets under reasonable terms and prices. With regard to the Federal Reserve's ("Fed") impacts on short-term and long-term market securities, and the resulting impact on short-term and long-term interest rates. Mr. Gorman concluded that the Federal Reserve's interactions in interest rate markets are fully known to market participants, and these interactions are fully considered in market participants' assessment of the current and projected interest rate markets. He stated that the actions taken by the Fed to increase the Federal Funds Rate have simply flattened the yield curve, and have not resulted in a corresponding increase in long-term interest rates. Additionally, he stated that the outlook for near-term Fed monetary policy actions is for further reductions to short- term interest rates. He concluded that the Fed monitory policy changes are important but the Fed actions have largely impacted short-term interest rates, while the cost of common equity is impacted by long-term interest rates. Accordingly, in his view, the Fed actions have not created pressure for the cost of equity capital to increase. While the Fed has participated in long-term interest rate markets, its participation has been significantly reduced and has not been proven to not have pressured long-term interest rates to increase. He noted that from 2008-2014, the Federal Reserve procured trillions of dollars in long-term securities to support the Federal Reserve's monetary policy, mitigate long-term interest rates, and to stimulate the economy – known as "quantitative easing." By purchasing these securities, the Federal Reserve was making capital more readily available at lower long-term interest rates. He further noted that the Federal Reserve has recently implemented a strategy to begin to unwind its balance sheet position in long-term interest rate and is reducing its participation in long-term interest rate markets. Mr. Gorman stated that because the Fed's actions are well-followed by market participants and captured in independent economists' outlooks for changes in capital market costs, the Fed's actions, along with all other relevant factors, are considered by consensus professional economists in forming their outlooks for changes in interest rates and capital market conditions. Mr. Gorman also testified that independent economists expect today's low capital costs to prevail over at least the intermediate term, as is illustrated in projections for both short- and long-term changes in interest rates. Further, he stated that there is a clear trend in forecasted changes in interest rates over time, indicating that capital market participants are becoming more comfortable with today's low-cost capital market and expect it to prevail over at least the intermediate future.

Mr. Gorman criticized Mr. Hevert's return on equity estimates as being "overstated"; he claimed Mr. Hevert's analyses produce excessive results for various reasons, including the following: (1) his constant growth DCF results are based on unsustainably high growth rates; (2) his CAPM is based on inflated market risk premiums; (3) his ECAPM is based on a flawed methodology; and (4) his Bond Yield Plus Risk Premium studies are based on inflated utility equity risk premiums. Mr. Gorman claimed that by making reasonable adjustments to Mr. Hevert's proxy group's DCF, CAPM, and Risk Premium return estimates, Mr. Hevert's own studies show that his 9.00% recommended return on equity for Duke Energy Indiana is reasonable.

Mr. Gorman testified that he believed his recommended rate of return would support an investment grade bond rating for the Company. He stated that he reached this conclusion by comparing the key credit rating financial ratios for Duke Energy Indiana at his proposed return on equity and embedded debt cost and Duke Energy Indiana's proposed capital structure to S&P's benchmark financial ratios using S&P's new credit metric ranges. He stated that based on an equity return of 9.0%, Duke Energy Indiana will be provided an opportunity to produce a Debt to Earnings Before Interest, Taxes, Depreciation and Amortization ("EBITDA") ratio of 4.1x. He stated that this is within S&P's "Significant" guideline range of 3.5x to 4.5x, which would support Duke Energy Indiana's credit rating. Additionally, he stated that Duke Energy Indiana's retail operations FFO to total debt coverage at a 9.00% equity return is 18.2%, which is within S&P's "Significant" metric guideline range of 13% to 23%. Again, he concluded this supports an FFO/total debt ratio that will support a ratio consistent with an A- rating.

With regard to Duke Energy Indiana-specific risks, Mr. Gorman simply stated that the major business risks identified by Mr. Hevert are considered in the assigning of a credit rating by the various credit rating agencies. Citing to his Attachment MPG-23, Mr. Gorman stated that the average S&P credit rating for his proxy group of BBB+ is lower than Duke Indiana's credit rating of A- from S&P, demonstrating that the proxy group is considered more risky than Duke Indiana. He stated that the relative risks discussed in Mr. Hevert's testimony are already incorporated in the credit ratings of the proxy group companies. He testified that S&P and other credit rating agencies go through great detail in assessing a utility's business risk and financial risk in order to evaluate their assessment of its total investment risk. He argued that this total investment risk assessment of Duke Indiana, in comparison to a proxy group, is fully absorbed into the market's perception of Duke Indiana's risk. Mr. Gorman concluded that the use of his proxy group fully captures the investment risk of Duke Indiana and is, in fact, conservative, given that the proxy group has a lower credit rating than Duke Indiana. Further, he stated that Duke Energy Indiana's capital expenditure forecasts do not present risks that are out of line with the utility industry.

iv. FEA's Evidence. Mr. O'Donnell testified that Mr. Hevert's recommended ROR is unreasonable, unnecessary, and excessive, and that the Company's allowed ROE should be set at 9.0%. He also critiqued Mr. Hevert's analyses. His recommendation in this case is for the Commission to grant Duke Energy Indiana a ROE of 9.0%. He stated that this 9.0% ROE is slightly above the midpoint of the DCF results for the proxy group, well above the CAPM results, and is slightly below the low end of the Comparable Earnings results.

He emphasized that interest rates remain quite low relative to historic levels, and individuals seeking an income stream see utility dividends as good alternatives at the present time with the lack of adequate fixed income (bond) opportunities. He stated that this "chase for yield" is part of the reason that the Dow Jones Utility Average has nearly tripled since 2008. In making his ROE recommendation, he stated he is recognizing the strength of the stock market over the past decade and actually recommending a ROE at the high end of his DCF results which, in his opinion, is the most indicative ROE model in use today by investors

Mr. O'Donnell testified that in his opinion, the DCF model is superior to the CAPM and comparable earnings approaches. He stated that the DCF is a pure investor-driven model that incorporates current investor expectations based on daily and ongoing market prices. When a situation develops in a company that affects its earnings and/or perceived risk level, the price of the stock adjusts immediately. Since the stock price is a major component in the DCF model, the change in risk level and/or earnings expectations is captured in the investor return requirement with either an upward or downward movement to account for the change in the company. Since the DCF captures immediate impacts to the company being analyzed, it is, in his view, a superior model relative to the CAPM and Comparable Earnings model.

He noted that the comparable earnings model is based on earned returns from book equity, not market equity. There is no direct and immediate stockholder input into the comparable earnings model and, as a fault, that model lacks a clear and unmistaken link to stockholder expectations. He further stated that the CAPM suffers, to a degree, from the same problem as the comparable earnings model in that there is not a direct and immediate link from stock market prices to the CAPM result. The beta in the CAPM can reflect changes in the ROE, but the delay can, sometimes, make the CAPM results meaningless.

Mr. O'Donnell testified that the dividend yield used should be 3.0% for the comparable group, and a range of 4.0% to 4.2% for Duke Energy Corp. In reaching this conclusion, he calculated the appropriate dividend yield by averaging the dividend yield expected over the next 12 months for each proxy company, as reported by the Value Line Investment Survey. The period covered is from June 28, 2019 through September 20, 2019. To study the short-term as well as long-term movements in dividend yields, he examined the 13-week, 4-week, and 1-week forecasted annual dividend yields for the proxy group as reported by Value Line. He developed the dividend yield range for the proxy group by averaging each Company's Value Line forecasted 12-month dividend yield over the above- stated 13-week, and 4-week periods as well as examining the most recent forecasted 12-month dividend yield reported by Value Line for each company. He stated that he averaged the dividend yield over multiple time periods in order to minimize the possibility of an isolated event skewing the DCF results.

To derive the expected growth rate, he used several methods in determining the growth in dividends that investors expect. The first method he used the "plowback ratio" method. The second method he used to estimate the expected growth rate was to analyze the historical 10-year and 5-year historical compound annual rates of change for earnings per share (EPS), dividends per share (DPS), and book value per share (BPS) as reported by Value Line for each of the relevant corporations. The third method he used was the Value Line forecasted compound annual rates of change for earnings per share, dividends per share, and book value per share. The fourth method he used was the forecasted rate of change for earnings per share as recorded by CFRA, a publication of S&P Global Market Intelligence. The last method he used was another forecasted earnings growth rate as supplied by Charles Schwab & Co. -- a compilation of forecasts by industry analysts.

He testified that Duke Energy's growth over the past 10 years has differed somewhat from the average of the comparable group. Over the 10-year study period, Duke Energy's earnings growth rates were significantly lower and its dividend growth rates were significantly higher than the average of the comparable group, while both earnings and dividend growth rates for Duke Energy lagged well behind the comparable group over the 5-year study period. In addition, the forecasted growth rates from Value Line provide a murky picture of the company's future, with Duke Energy's earnings growth rates predicted to be slightly higher but its dividend growth rates predicted to be significantly lower than those of the comparable group. Meanwhile, the CFRA and Schwab forecasted earnings growth rates for Duke Energy are below the corresponding growth rates for the comparable group.

He testified that the dividend yield for the three timeframes held steady at 3.0% for the comparable group, while the dividend yield for Duke ranged from 4.0% to 4.2% over the three time periods. The comparable group has grown at a solid and steady pace. Over the past 10- years, the comparable group has grown in the range of approximately 4.2% (Value Line 10-year BPS) to 5.7% (Value Line 5-year DPS). The forecasted growth rates for the comparable group are in line with historical growth rates and are in the range of 4.2% (Value Line Forecasted BPS) to 5.8% (Value Line Forecasted EPS). The plowback growth rate average for the comparable group is 3.5%. The historical growth rates for Duke Energy, on the other hand, have ranged from 0.5% (Value Line 5-year EPS) to 7.0% (Value Line 10-year DPS), thereby showing quite a discrepancy. Duke Energy's forecasted growth rates maintain this trend of uncertainty, ranging from 2.5% (Value Line forecasted BPS) to 6.0% (Value Line forecasted EPS). The plowback for Duke Energy is 1.7%.

In terms of the proper dividend growth rate to employ for the comparable group in the DCF analysis, he argued it is appropriate to examine the recent history of earnings and dividend growth to assess and provide the best estimate of the dividend growth that investors expect in the future. An examination of the 10-year and 5-year historical growth rates for the comparable group show that dividends have been growing slightly faster than earnings. Dividends cannot, however, sustain a higher growth rate than earnings over the long-term as, eventually, there will not be sufficient earnings to pay dividends. The market expects this situation to right itself in the future as the Value Line forecasted dividends for the group is forecasted to be 5.5% (Value Line Forecasted DPS) whereas the earnings growth is expected to be 5.8% (Value Line Forecasted EPS).

Based on these results, Mr. O'Donnell testified that he believes the proper growth rate range to use in the DCF model for the comparable group is 4.0% to 6.0%. The low-end (4.0%) of this range is close to the 10-year historical growth in earnings and book value whereas the high end (6.0%) of the range is approximately equal to the high end of the range for the forecasted growth in earnings for the comparable group.

While the dividend yield of Duke Energy is higher than that of the comparable group, Mr. O'Donnell testified that the market is expecting Duke's growth prospects to be generally lower than those of the comparable group (in all categories except the Value Line forecasted EPS, of which Duke Energy's is slightly higher, at 6.0% compared to 5.8%). He stated that he believed a growth rate range of 3.5% to 5.5% should be used in the DCF model for Duke Energy. The 3.5% bottom end of the range represents the approximate midpoint of the 10-year historical Duke Energy results as reported by Value Line. The high end of the range (5.5%) reflects the stronger earnings expected from Duke Energy in the future when compared to dividend and book value growth.

His analyses produce a DCF range of 7.25% to 9.25%. Combining the dividend yields of the comparable group with the growth rate range cited above, and doing the same for Duke Energy, produces the results as stated below:

Table 8: DCF Results

	Forecasted Div. Yld		Exp Growth Rate Range		DCF Results	
	Low	High	Low	High	Low	High
Comparable Group	3.0%	3.0%	4.0%	6.0%	7.0%	9.0%
Duke Energy	4.0%	4.2%	3.5%	5.5%	7.5%	9.7%

Combining the proxy group's dividend yield of 3.0% with the growth rate range of 4.0% to 6.0% produces a DCF range of 7.0% to 9.0%. Combining the above-stated Duke Energy Corp. yield range of 4.0% to 4.2% with the growth rate range of 3.5% to 5.5% produces a DCF range of 7.5% to 9.7%. Based on these results, Mr. O'Donnell opined that the DCF results are in the range of 7.25% to 9.25%.

In the CE analysis Mr. O'Donnell performed in this case, he examined actual earned returns on book value, not market value. He testified that he believes the stated returns on book value, such as provided by Value Line, should be used only as a guide to the DCF market-required estimates. In his comparable earnings analysis, Mr. O'Donnell picked a range of earned returns on equity of the comparable group over the period of 2017 through 2024. He picked this range to provide the Commission with two years of historical returns and five years of forecasted returns. The average earned returns on equity for the proxy group range from 9.6% to 10.5%. For Duke Energy Corp., the average earned ROEs range from 6.7% to 8.5%.

Mr. O'Donnell presented another comparable earnings analysis, based on ROEs granted by state regulators across the country. He observed that regulated ROEs have trended down over the past 15 years. As for the most recent year, 2018, the overall allowed ROE for electric utilities was 9.60%, which was down from the 9.74% allowed ROE for electric utilities in 2017. He noted that recently, the South Carolina Commission authorized 9.5% ROEs for Duke Energy Carolinas and for Duke Energy Progress. He also noted that the South Dakota Commission authorized an 8.75% ROE for Otter Tail Power in May 2019.

Based on the above-stated findings, Mr. O'Donnell believes the proper ROE using a comparable earnings analysis is in the range of 9.25% to 10.25%. The lower end of this range recognizes the downward trend of the average ROE allowed by state regulators for electric utilities dating back to 2003 as well as the lower earned returns for the comparable group and Duke Energy from 2017 through 2019. The high end of the range recognizes high forecasted earned returns on equity for the comparable group.

Mr. O'Donnell stated that the development of the current market risk premium is, undoubtedly, the most controversial aspect of the CAPM calculations. To gauge the historical risk premium, he turned to the Ibbotson database published by Morningstar, as well as various forecasts. He noted that the equity returns display a very large range, with a mid-range estimate of 4% to 6% for the group. He concluded that, using historical data as well as forecasted data, the evidence suggests the equity risk premium is within the range of 4% to 6%. To determine the beta, he used the Value Line derived beta found in the most recent Value Line editions for each company in the proxy group.

Mr. O'Donnell testified that the proxy group CAPM results range from 4.3% to 7.0%. For Duke Energy Corp., the beta is 0.50 which, when applied to the 4.0% to 6.0% risk premium, results in a 2.0% to 3.0% beta-adjusted risk premium. The risk-free rate range of 1.94% to 3.46% is added to this beta-adjusted risk premium range and the results are a CAPM range of 3.9% to 6.5%. Based on this range of results for the CAPM, he found the proper ROE derived from the CAPM is in the range of 5.0% to 7.0%. The low-end (5.0%) of this range is at the low-end of the proxy group and Duke Energy Corp. CAPM results using the 4.0% of the equity risk premium. The high end (7.0%) of the range is slightly lower than the high end of the proxy group CAPM results using the 6.0% equity risk premium.

Table 10: ROE Method Results

	ROE Results	
Method	Low	High
DCF	7.25%	9.25%
Comparable Earnings	9.25%	10.25%
CAPM	5.00%	7.00%

Mr. O'Donnell critiqued Mr. Hevert's ROE analyses. He contended that Mr. Hevert has changed the application of his cost of capital models over the years so that the results produce higher cost of capital results for his utility clients. He stated that Mr. Hevert has changed his application of the CAPM in two very distinct ways: (1) he has changed the actual market risk premiums used in the CAPM; and (2) he has changed his reliance on historical data versus forecasted data as employed in the CAPM. The result of these two changes, Mr. O'Donnell stated, is that Mr. Hevert's calculations lead to higher ROE for his clients. Additionally, he testified, Mr. Hevert's testimony exhibits inconsistency in his application of the CAPM. Specifically, he pointed to a comparison between Mr. Hevert's regression analysis in this case versus a previous South Carolina case, where he found different risk premiums to be appropriate. Mr. O'Donnell also pointed to Mr. Hevert's use of a "Multi-Stage DCF" model in one past case, which he did not present in this case, but did not present that model in this case. Although, given the weaknesses of the Multi-Stage DCF model, Mr. O'Donnell stated, he was not surprised to see that Mr. Hevert stopped using the Multi-Stage DCF model. Again comparing this case to a previous South Carolina case, Mr. O'Donnell also pointed out that Mr. Hevert has changed the weights he places on the methods. Mr. O'Donnell stated that he does not agree that the current market is so different from past markets that analysts should change their cost of capital methodologies from case-to-case.

Mr. O'Donnell next discussed the company-specific risks Mr. Hevert addressed. He characterized the coal generation in the Company's portfolio as an investment opportunity, rather than a risk, noting that the Company's IRP calls for a number of new generation investments to replace retiring coal plants over the years. He argued that the gas plant, wind, and solar investments coupled with recovery of undepreciated coal plant costs should provide Duke Energy Indiana with strong earnings for years to-come.

With regard to the regulatory mechanisms in place, Mr. O'Donnell generally agreed with Mr. Hevert that various cost recovery mechanisms are widespread within the electric utility industry. He stated that investors have accepted the existence of these rate recovery tariffs and priced the utility stock in recognition of these risk-lowering mechanisms. But, while he agrees with Mr. Hevert that the Commission need not recognize existing rate recovery tariffs in terms of a lower ROE, he disagrees with Mr. Hevert regarding the revenue decoupling proposed by the Company in this case. He stated that revenue decoupling is a new tariff for the Company that will reduce risk even further for Duke Energy Indiana and should be recognized accordingly with a lower ROE.

v. **Walmart's Evidence.** Mr. Chriss recommended that the Commission closely examine the Company's proposed ROE, especially in light of the customer impact of the resulting revenue requirement increases, the use of a future test year, which reduces regulatory lag, recent ROEs approved by the Commission, recent rate case ROEs approved by other state regulatory commissions for other Duke Energy subsidiaries, and recent rate case ROES approved by other state regulatory commissions nationwide. Mr. Chriss stated that the average IURC-approved ROE since 2016 is 9.94%. He also testified that the South Carolina Commission authorized ROEs of 10.1% and 9.5% for Duke Energy Progress in 2016 and 2019, respectively; the North Carolina Commission approved ROEs of 9.9% for Duke Energy Carolinas and Duke Energy Progress in 2018; and the Ohio Commission approved an ROE of 9.84% for Duke Energy Ohio in 2018. Additionally, he testified that according to S&P Global Market Intelligence, the average of the 128 reported electric utility rate case ROEs authorized by state regulatory commissions to investor-owned utilities (including distribution-only utilities) in 2016 to 2019 (to date) is 9.6%; the range of reported authorized ROEs for the period is 8.4% to 11.95%, and the median authorized ROE was 9.6%, well below the Company's proposed ROE of 10.4%. Mr. Chriss noted that the average ROE for vertically integrated utilities over the same period was 9.73%. Mr. Chriss concluded his testimony by commenting that decisions of other state regulatory commissions are not binding on this Commission -- rather, each commission considers the specific circumstances in each case in its determination of the proper ROE. He stated that Walmart is providing this information on industry trends on ROE from its perspective as a customer with operations that are nationwide as it believes that recently authorized ROEs in other jurisdiction provide a general gauge of reasonableness for the various cost of equity analyses presented in this case. Moreover, Walmart believes that it is appropriate for the Commission to consider how any ROE authorized in this case impacts existing and prospective customers relative to other jurisdictions.

vi. **Petitioner's Rebuttal Evidence.** Mr. Hevert's rebuttal testimony responded to the direct testimonies of Mr. Garrett, on behalf of the OUCC; Mr. Gorman, on behalf of the Duke Industrial Group; Mr. O'Donnell, on behalf of the Department of Navy and FEA; and Mr. Chriss, on behalf of Walmart Inc. (together "the Opposing ROE Witnesses") as their testimony relates to the ROE. In response to the Opposing ROE Witnesses' testimonies, he updated many of the analyses contained in his Direct Testimony and provided several analyses developed in response to the Opposing ROE Witnesses.

Mr. Hevert indicated that he continues to believe an ROE in the range of 10.00% to 11.00% represents the range of equity investors' required ROE for investment in electric utilities like Duke Energy Indiana in the current capital market environment. Within that range, he indicated he continues to believe an ROE of 10.40% is reasonable and appropriate.

He testified there are several methodological, theoretical, and practical reasons why he believes the Opposing ROE Witnesses' recommendations are unduly low. He noted that, because the Opposing ROE Witnesses give meaningful weight to their DCF-based results, it is not surprising that their recommendations fall well below currently authorized returns. He reiterated that, since 2014 the Constant Growth DCF model has produced ROE estimates notably below the returns then authorized by regulatory commissions. He stated that, given their common reliance on the DCF method, it also is not surprising that the Opposing ROE Witnesses' recommendations generally fall within a narrow range. He stated, however, that the fact that their recommendations are similar does not mean their approaches and conclusions are reasonable.

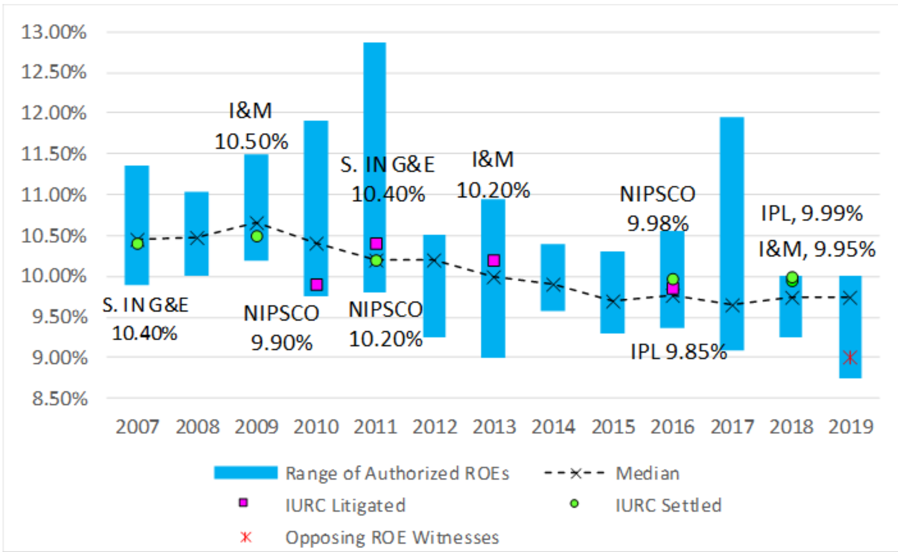
Mr. Hevert reiterated that the Opposing ROE Witnesses' recommendations fall from unreasonably low Discounted Cash Flow ("DCF") estimates, which are based on assumptions that do not align with market conditions. Because the Constant Growth DCF assumes valuation levels (including the Price to Earnings, or "P/E", ratio) and the calculated Cost of Equity will remain constant in perpetuity, it assumes market conditions that support its current results also will remain in place, forever. He noted, however, that market volatility, including volatile interest rates, however, have disrupted relationships assumed under the Constant Growth DCF model's structure. Consequently, he stated that the model's assumption of constancy in perpetuity should be considered with caution, as it applies to the utility proxy companies used by the ROE witnesses in this proceeding. He testified that one cannot conclude the recent levels of utility valuations are due to a fundamental and permanent change in the risk perceptions of utility investors, as the Opposing ROE Witnesses' recommendations assume. Those valuation levels more likely are related to investors' "reach for yield" that often occurs during periods of low Treasury yields. He emphasized that regulatory commissions have recognized the Constant Growth DCF model's assumptions are likely to produce unreliably low results, and he noted that position is consistent with the observation that 94 of 104 (i.e., 90%) authorized vertically integrated utility ROEs since 2015 were above the highest of the Opposing ROE Witnesses' ROE recommendations (9.30%). And in 2019, he noted, nine of 16 were above 9.70%. He testified that Mr. Garrett's DCF and Capital Asset Pricing Model ("CAPM") estimates, in particular, are so far removed from the range of recently authorized ROEs that they should be considered outliers. He stated that Mr. Gorman's ROE recommendation also is low relative to recently authorized returns for vertically integrated electric utilities, which have averaged approximately 9.74% since 2015.

Mr. Hevert further testified that certain of the Opposing ROE Witnesses' recommendations are fundamentally disconnected from their own analyses and conclusions and are far removed from observable and relevant data. For example, he noted that throughout his testimony, Mr. Garrett argues the Company's "true" cost of equity is in the range of 6.30%. Mr. Garrett reasons that having been quite wrong for so long, it is time for regulatory commissions to move toward the "true" cost of equity, but at a gradual pace. He therefore recommends an ROE of 9.00% to mitigate the adverse market reaction that surely would follow if his "true" cost of equity were adopted. Mr. Hevert pointed out that, aside from Mr. Garrett's view that regulatory commissions have been consistently and substantially incorrect, and his concern that moving too quickly to the "true" cost of equity would create market risk, Mr. Garrett provides no basis, empirical or otherwise, for his specific 9.00% ROE recommendation. Mr. Hevert concludes that, putting aside the many methodological concerns with his approach, Mr. Garrett's recommendation is without merit, and should be given no weight.

Mr. Hevert testified that, although Mr. Gorman suggests the cost of equity has fallen to a level that supports his recommendation, observable data does not support his position. He also noted that Mr. O'Donnell supports his 9.00% recommendation, in part, by reference to historically low interest rates, and high utility stock prices. Mr. Hevert pointed out, however, that authorized ROEs have not moved in lock-step with interest rates. For those reasons, and many others articulated in his rebuttal testimony, Mr. Hevert strongly disagrees that the Company's cost of equity is 9.00%, or lower, as the Opposing ROE Witnesses propose.

Mr. Hevert testified and illustrated that the Opposing ROE Witnesses' recommendations are well below the median ROE authorized for vertically integrated electric utilities – and they are well below the ROEs authorized by the Commission (which range from 9.85 percent to 10.50 percent since 2009):

Authorized ROEs for Vertically Integrated Electric Utilities (2009 – 2019)[19]



Mr. Hevert emphasized that if the Commission were to authorize a return of 9.00 percent or lower as the Opposing ROE Witnesses recommend, it would represent a significant departure from returns recently authorized by the Commission. Further, he emphasized that the financial community carefully monitors the regulatory environment in which utilities operate. For example, he stated that Moody's finds the regulatory environment to be so important that 50% percent of the factors that weigh in its ratings determination are determined by the nature of regulation. He stated that because they represent a significant departure from regulatory practice and would dilute the Company's cash flow, the Opposing Witnesses' recommendations would considerably increase its risk profile, to the detriment of investors and customers.

In response to the Opposing ROE Witnesses, Mr. Hevert updated his Constant Growth DCF, Capital Asset Pricing Model, Empirical CAPM, Bond Yield Plus Risk Premium, and Expected Earnings analyses to reflect data as of October 31, 2019. He also updated his proxy group

[19] Source: Regulatory Research Associates. Mr. Hevert noted that in Cause No. 43526 the Commission authorized a 9.90 percent ROE for Northern Indiana Public Service Company ("NIPSCO"), the low end of its 9.90% to 10.50% range of reasonableness, due to the reduction in risk to NIPSCO related to the Commission's approval of a new industrial service rate structure. And in Cause No. 44576, the Commission authorized a 9.85% ROE for Indianapolis Power & Light Co. ("IPL"), which represented the midpoint between IPL's unadjusted ROE of 10.00% and the low end of the range 9.70%, due to management performance factors.

to include Avista Corporation ("Avista") because sufficient time has passed since the proposed acquisition of Avista by Hydro One Limited was terminated.

Mr. Hevert also offered numerous specific and technical responses to Mr. Garrett's testimony, in the following areas: (1) his view that the "true" cost of equity is 6.30%; (2) the growth rate assumptions used in his DCF analyses; (3) the application of the CAPM; (4) the relevance and interpretation of the Bond Yield Plus Risk Premium approach; (5) the relevance of flotation costs in determining the Company's Cost of Equity; and (6) the risks associated with Duke Energy Indiana's generation portfolio and related environmental regulations; and (7) the implications of Mr. Garrett's recommendations for the Company's credit profile.

With regard to Mr. Garrett's testimony on utility risk profiles and the cost of equity, Mr. Hevert responded with the following:

- Although utility Beta coefficients tend to be less than 1.00 (that is, by that measure they are less risky than the overall market), regulation does not insulate utilities from either business or market risks. Further, not even relatively low-beta securities such as regulated utilities are unaffected by market conditions

- Because the range of Mr. Garrett's Beta coefficients is within one standard deviation, one cannot say with certainty that company-specific risks are diversifiable (as Mr. Garrett suggests they will be). Because the range of Beta coefficients produces a rather wide range of CAPM estimates (even assuming Mr. Garrett's Market Risk Premium), Mr. Hevert continues to believe it is reasonable to consider company-specific risks in determining the Company's cost of equity.

With regard to Mr. Garrett' testimony regarding the Constant Growth and Quarterly DCF Models, Mr. Hevert responded as follows:

- Mr. Garrett assumes a single, perpetual growth rate of 3.90% for all his proxy companies. After adjusting for inflation, Mr. Garrett's method assumes his proxy companies all will grow at real rates of approximately 1.90%, in perpetuity. It is unlikely an investor would be willing to assume the risks of equity ownership in exchange for expected growth only modestly greater than expected inflation; the risk simply is not worth the expected return.

- As to Mr. Garrett's remaining growth rate estimates, none are appropriate measures of growth for his DCF analysis. Because they are generic in nature, or specific only to Duke Energy Indiana, they fail to account for the risks and prospects faced by the proxy companies.

- Additionally, Mr. Garrett's 3.90% growth rate is not based on any measure of company-specific growth, or growth in the utility industry in general. Rather, his proxy group serves the sole purpose of calculating the dividend yield. Under the DCF model's strict assumptions, however, expected growth and dividend yields are inextricably related. Mr. Garrett's assumption that one growth rate applies to all companies, even though dividend yields vary across those companies, has no basis in theory or practice.

- Mr. Garrett's use of Duke Energy Indiana's projected customer growth rate applied to all companies has no basis in theory or practice. Additionally, because Duke Energy Indiana's projected customer growth is 0.50 percent, Mr. Garrett assumes earnings for his proxy group will remain essentially flat (or negative in real terms, assuming his 2.00 percent inflation rate). As noted above, under that scenario investors more likely would prefer debt securities. Also, the use of Duke Energy Indiana's projected customer growth runs counter to Mr. Garrett's position that Company-specific factors have no bearing on the cost of equity.

- Mr. Garrett's position that load growth is a reasonable measure of a company's expected growth in the DCF model assumes there is a direct path from electric retail sales to earnings. As a practical matter, however, many variables enter that relationship. Rate design, for example, may affect the relationship between retail sales and revenues. The relationship between revenue and earnings likewise is a function of operating margins, which in turn, are influenced by a variety of operating factors, such as productivity improvements. Analysts' expectations for earnings growth are not limited by retail electric sales growth, and Mr. Garrett's focus on that single factor is inconsistent with actual practice.

- With respect to Mr. Garrett's criticism of Mr. Hevert's DCF model growth estimates, the relevant issue is not whether Mr. Garrett believes the analysts' growth rates included in Mr. Hevert's model are proper, it is whether investors rely on them. Mr. Garrett has not shown analysts' earnings growth rate expectations are unrelated to expected capital appreciation or investors' return requirements. Rather, investors rely on analysts' forecasts in framing their investment decisions.

With regard to Mr. Garrett's CAPM analysis, Mr. Hevert made the following points in response:

- Mr. Hevert disagrees with Mr. Garrett's sole reliance on historical Treasury yields to estimate the risk-free rate and the various methods he uses to estimate the Market Risk Premium. Just as important as the methodological differences, however, is the difference regarding the reasonableness and reliability of an analysis that produces ROE estimates of 5.60%.

- With regard to the risk-free rate component of the CAPM, and Mr. Garrett's use of the average 30-year Treasury yield, although Mr. Hevert agrees it is appropriate to consider the current average 30-year Treasury yield, because the cost of equity is forward-looking it also is important to reflect forward-looking expectations of the risk-free rate. For that reason, Mr. Hevert relied on both the current 30-day average 30-year Treasury yield and the projected near-term 30-year Treasury yield.

- The surveys referenced by Garrett do not provide reasonable market risk premium estimates for cost of capital purposes. For example, the Graham and Harvey survey suggests an expected return on the overall market of 6.79%, based on a risk-free rate of 2.37% and an market risk premium of 4.42%. Combining those estimates with Mr. Garrett's average Beta coefficient estimate of 0.57 produces a cost of equity estimate of 4.89%, only one basis point above the Company's initial proposed cost of debt (23 basis points above Mr. Garrett's recommended 4.66% cost of debt), and approximately 140 basis points below Mr. Garrett's estimate of the "true" cost of equity. Moreover, in the past the Graham and Harvey survey respondents have provided forecasts that significantly underestimated actual market returns; from 2012 through 2018 the average market return was 13.27%, about 2.50 times greater than the Graham and Harvey survey average expected return of 5.30%.

- Mr. Hevert noted that he calculated the ex-ante Market Risk Premium in a similar manner to a study by Pablo Fernandez, et al (cited by Mr. Garrett), using the market capitalization weighted Constant Growth DCF calculation on the individual companies in the S&P 500 Index.

- Regarding Mr. Garrett's assumed first-stage growth rate, Mr. Garrett's 6.04% growth rate relates to growth in operating earnings, and does not reflect capital appreciation, growth in dividends, or buy-backs. In addition, if Mr. Garrett's position is that historical growth rates are meant to reflect expected future growth, they should reflect year-to-year variation (that is, uncertainty).

- Because Mr. Garrett's model assumes the first stage lasts for five years (and the terminal stage is perpetual), the results are sensitive to changes in the assumed terminal growth rate. To put that effect in perspective, the terminal value (which is directly related to the terminal growth rate) represents approximately 75% of the "Intrinsic Value" in Mr. Garrett's analysis.

- Regarding Mr. Garrett's terminal growth rate assumption, Mr. Garrett has not explained why growth beginning five years in the future, and extending in perpetuity, will be less than one-third to one-half of long-term historical growth. Nowhere in his testimony has Mr. Garrett explained the fundamental, systemic changes that would so dramatically reduce long-term economic growth, or why they are best measured by the long-term Treasury yield over 30 days between late July to early September 2019. Further, research by the Federal Reserve Bank of San Francisco calls into question the relationship between interest rates and macroeconomic growth; as the authors noted, "[o]ver the past three decades, it appears that private forecasters have incorporated essentially no link between potential growth and the natural rate of interest: The two data series have a zero correlation." Lastly, over the 30 trading days ended September 5, 2019 the 30-year Treasury yield fell by 54 basis points, a decline of about 20.77%. Mr. Garrett has not explained why such an abrupt and meaningful decline in Treasury yields should be taken as a measure of a sudden and abrupt decline in expected earnings growth five years from now.

- Mr. Garrett's equity risk premium calculation is based on a series of questionable assumptions, to which a small set of very reasonable adjustments produces a market return estimate more consistent with (yet still below) the historical experience he considers relevant. Although the revised results still produce ROE estimates far below any reasonable measure, they do point out the sensitive nature of Mr. Garrett's analyses, and the tenuous nature of the conclusions he draws from them.

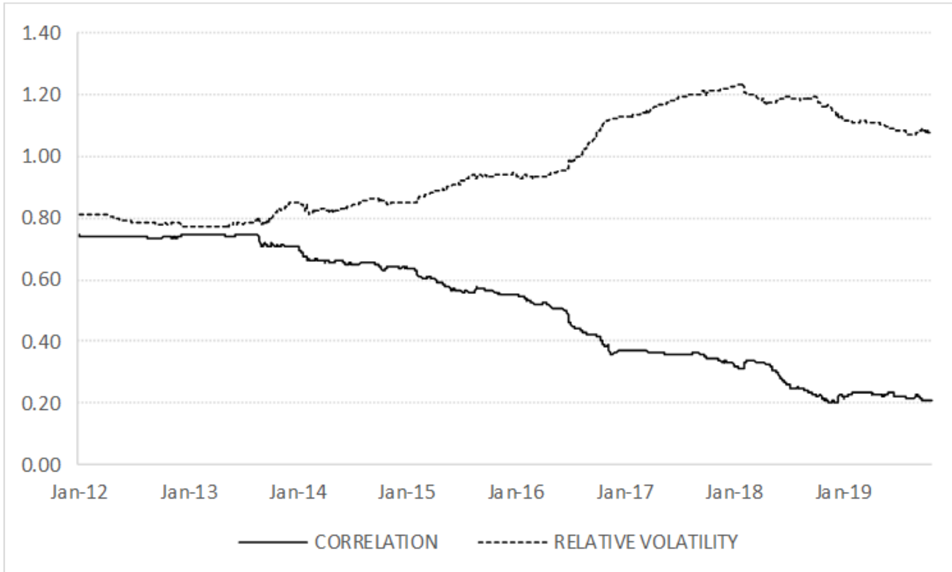
- In determining the expected growth rate that underlies the expected market return, the salient points are twofold: (1) investors rely on analysts' growth rate projections to frame their investment decisions; and (2) because it is meant to estimate the market return, it is the expected return on the 500 companies in the S&P 500 that matters. As to the first point, Mr. Garrett has not shown investors avoid analysts' projections. He certainly has not shown investors find his 8.19% expected market return (based on his Implied Equity Risk premium analysis) more reliable than the combined estimates of the many analysts that follow the companies comprising the S&P 500. Regarding the second point, over time the average annual total return on large company stocks has been about 11.90%. From 2013-2018, the period on which Mr. Garrett's Implied Equity Risk Premium is based, the average return was 12.81%.

- Additionally, although Mr. Garrett observes one company in my analysis with a high, positive growth rate, he fails to point out the several with negative growth rates.

- Regarding Mr. Garrett's view that the Beta coefficients derived from value line "may lead to overestimated results, given the commercial use and longstanding acceptance of adjusted Beta coefficients, it is Mr. Hevert's view that they are the proper measure of systematic risk in the CAPM. And despite his concerns regarding that adjustment, Mr. Garrett relies on value line Beta coefficients to produce his CAPM-based estimate of 5.60

- Beta coefficients reflect two components: (1) the relative volatility of returns, and (2) the correlation in returns between the subject company and the overall market. Looking at those individual measures, since 2012 the correlation between Mr. Garrett's proxy group and the S&P 500 has declined whereas the relative volatility has increased:

Components of Beta Coefficients Over Time for Mr. Garrett's Proxy Group and the S&P 500[20]



- Beginning in 2012 the Federal Reserve began its third round of Quantitative Easing, which was meant to put downward pressure on long-term interest rates. The effect of that policy may have been to encourage investors, at times, to "reach for yield" by investing in dividend-paying sectors, such as utilities. Because utilities faced downward credit pressure due to the Tax Cuts and Jobs Act ("TCJA"), and because utilities could not benefit from the TCJA in ways other sectors could, they became relatively less attractive.

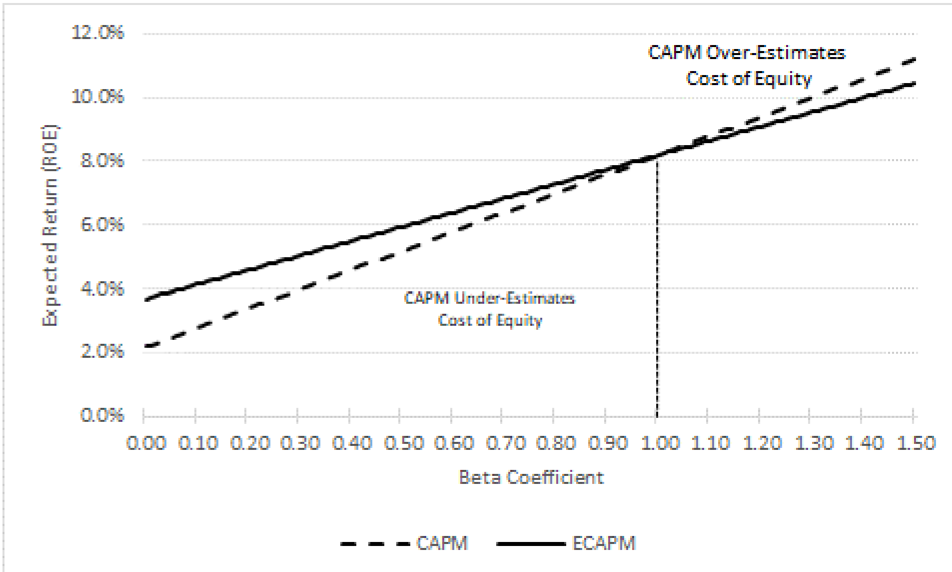
- At the same time, the volatility in utility returns increased relative to the overall market. The analytical issue is whether current Beta coefficients, even though adjusted, reasonably reflect expected systematic risk. Published research has found low-Beta coefficient companies (such as utilities) have tended to earn returns greater than those predicted by the CAPM. Given the decline in correlations discussed above, that may be an even more acute concern in the current market.

- One method to address the change in Beta coefficients is to apply the Empirical form of the ECAPM, which adjusts for CAPM's tendency to under-estimate returns for companies that (like utilities) have Beta coefficients less than the market mean of 1.00, and over-estimate returns for relatively high-Beta coefficient stocks. Fama and French described the empirical issue addressed by the ECAPM, noting that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low." Similarly, Dr. Roger Morin observes that "[w]ith few exceptions, the empirical studies agree that … low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted."

[20] Source: S&P Global Market Intelligence.

- The relationship between expected returns from the CAPM and ECAPM can be seen below. This chart, which reflects Mr. Garrett's risk-free rate and MRP, illustrates the extent to which the CAPM understates the expected return relative to the ECAPM when Beta coefficients – whether adjusted or unadjusted – are less than 1.00.

CAPM and ECAPM Expected Returns



- Research suggests the ECAPM mitigates, but does not solve the issue of the CAPM underestimating returns for low-Beta coefficient firms.

- In summary, the CAPM tends to underestimate returns for low-Beta coefficient firms. The ECAPM moderates that effect to some extent, but it does not appear to eliminate it. Because the ECAPM mitigates the drift in Beta coefficients (which Mr. Garrett addresses in his discussion of adjusted Beta coefficients), Mr. Hevert believes it is a reasonable method, and continue to include the results of the ECAPM in his updated analyses.

With regard to Mr. Garrett's Bond Yield Plus Risk Premium Analysis, Mr. Hevert responded with the following points:

- Mr. Garrett argues the analytical objective should be "to use objective, market-based models (the DCF and CAPM) to estimate the cost of equity." His position that Risk Premium models are "almost exclusively seen in the testimonies of utility ROE witnesses" is highly questionable. Although Mr. Garrett does not explain what he means by "almost exclusively," Mr. Hevert noted that in 2019 alone he has seen regulatory staff and other intervenor witnesses include a risk premium-based model in several cases, including Mr. Gorman in this proceeding.

- Despite Mr. Garrett's concerns, authorized returns and their associated proceedings reflect the same type of market-based analyses at issue in this proceeding. Because authorized returns are publicly available (the proxy companies disclose authorized returns, by jurisdiction, in their 2018 SEC Form 10-Ks), it therefore is reasonable to conclude that data is reflected, at least to some degree, in investors' return expectations and requirement. Further, although there is no disagreement that every case has its unique set of issues and circumstances, reviewing approximately 1,600 cases over many economic cycles and using that data to develop the relationship between the Equity Risk Premium and interest rates mitigates that concern.

- Contrary to Mr. Garrett's assertion, the Bond Yield Plus Risk Premium approach generally is covered in basic finance texts, including for example, Brigham and Gapenski.[21]

- The point made by Mr. Hevert's Risk Premium approach, which is that the Equity Risk Premium is inversely related to interest rates, also is the subject of published academic research. Although Mr. Garrett believes such research is only provided by utility witnesses, published academic research performed by Staff members of the Virginia Corporation Commission (i.e., Maddox, Pippert, and Sullivan) has also shown the Equity Risk Premium to be inversely related to interest rates.[22] Those authors also found that the Equity Risk Premium is not stable over time, and increases as interest rates decrease. In short, Mr. Garrett's assertion is highly questionable, but the important finding that Equity Risk Premium are nonconstant and vary with interest rates is not.

- Lastly, Mr. Garrett's statement that Risk Premium models are "almost" exclusively found in utility witness' testimony is dubious, as well. In recent cases, Mr. Hevert has seen regulatory staff witnesses include Risk Premium analyses in Texas (PUC Docket Nos. 49421 and 49494), North Carolina (Docket No. G-9, Sub 743), and Arkansas (Docket No. 19-008-U). Mr. Garrett's assertions that the method "is used to justify a cost of equity that is much higher than one that would be dictated by market forces," and that the model is "used to perpetuate the discrepancy between awarded ROEs and market-based cost of equity" simply are incorrect. An alternative, and more likely interpretation is that Mr. Garrett's view that the Cost of Equity is less than 7.00% is inconsistent with the findings of regulatory commissions, who have considered expert testimony from many sources over many years.

In response to Mr. Garrett's position that Mr. Hevert's bond yield plus risk premium analysis is not forward-looking, Mr. Hevert responded as follows:

- Mr. Garrett is incorrect. The approach quantifies the longstanding principle that the Equity Risk Premium is not constant, but varies over time, and with market conditions. Mr. Hevert's model as applied reflects variable market conditions in changing interest rates. Applying forward-looking (projected) interest rates will produce varying

---

[21] Eugene F. Brigham, Louis C. Gapenski, Financial Management, Theory and Practice, 1994, The Dryden Press., at 341.
[22] Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, (Autumn 1995), at 89-95.

estimates of the Equity Risk Premium. The model, and its results, therefore, are forward-looking.

Regarding the issue of flotation costs, Mr. Hevert responded as follows:

- Mr. Garrett's observation that underwriter fees are not "out-of-pocket" expenses is a distinction without a meaningful difference. Whether paid directly or indirectly through an underwriting discount, the cost results in net proceeds that are less than the gross proceeds. Whether the issuer wrote a check or received the proceeds at a discount does not matter. What does matter is that issuance costs are a permanent reduction to common equity, and absent a recovery of those costs, the issuing company will not be able to earn its required return.

- Although Mr. Garrett suggests current prices account for flotation costs, he has provided no explanation as to how market prices compensate shareholders for flotation costs or any analyses to support his position. Equity flotation costs and debt issuance expenses both are necessary and legitimate costs enabling the investment in assets needed to provide safe and reliable utility service; both should be recovered.

Regarding the credit implications of Mr. Garrett's recommendations, Mr. Hevert responded as follows:

- Mr. Garrett has not considered the likely consequences for the Company's credit profile if the commission were to accept his ROE recommendation. In Mr. Hevert's view, it is quite likely rating agencies would view Mr. Garrett's proposed ROE as a negative development, putting downward pressure on the Company's credit ratings, for two reasons: (1) the diminished cash flows from the lower return would have a direct, downward effect on the cash flow-based metrics that are central to credit determinations; and (2) such a decision would present a significant departure from the Commission's past practice, introducing a high degree of regulatory uncertainty and risk.

- The financial community focuses on the level and predictability of future cash flows. Moody's, for example, notes that 32.50 percent of the weight it gives to various factors considered in its ratings determinations are focused on cash flow.[23] It does so because "[f]inancial strength, including the ability to service debt and provide a return to shareholders, is necessary for a utility to attract capital at a reasonable cost in order to invest in its generation, transmission and distribution assets, so that the utility can fulfill its service obligations at a reasonable cost to rate-payers."[24]

- Standard & Poor's also makes clear that cash flow-based metrics are integral to its assessment of the "Financial Risk Profile" which, when combined with the "Business Risk Profile" forms the basis of its rating assessment. Because both the authorized ROE and capital structure directly affect earnings, the Commission's decision would

[23] Moody's Investors Service, *Rating Methodology; Regulated Electric and Gas Utilities*, June 23, 2017, at 6.
[24] *Ibid*., at 20.

have a direct effect on the Company's cash flows and, therefore, on the credit metrics that both Moody's and S&P find critically important in their rating process.

- As to the importance of stability and predictability, Moody's describes the circumstances that correspond to rating in the "A" category as follows: "The issuer's interaction with the regulator has led to a strong, lengthy track record of predictable, consistent and favorable decisions. The regulator is highly credit supportive of the issuer and utilities in general. We expect these conditions to continue."

- Similarly, S&P explains the regulatory structure is one of the most important factors in its credit rating analyses: "For a regulated utility company, the regulatory regime in which it operates will influence its performance in profound ways. As such, Standard & Poor's Ratings Services' regulatory advantage assessment - - which informs both our business and financial risk scores - - is one of the most important factors in our credit analysis of regulated utilities…. Our assessment of a utility's regulatory regime rests on four pillars: regulatory stability, efficiency of tariff-setting procedures, financial stability, and regulatory independence…. We believe these factors strongly influence a utility's credit quality and its ability to recover its costs and earn a timely return."

- The loss of predictability resulting from a significantly lower rate of return, brought about by an ROE premised on a "true" cost of equity of 6.30%, undoubtedly would be viewed as negative for the Company's credit profile.

Mr. Hevert also responded to Mr. Gorman's testimony. Mr. Hevert testified that he disagreed with Mr. Gorman in several principal areas, including: (1) the effect of market conditions and utility risk profiles on the Company's cost of equity; (2) the application of the DCF model, and interpretation of its results; (3) the Market Risk Premium component of his CAPM analysis, in particular the expected market return from which the Market Risk Premium is calculated; and (4) the assumptions and methods underlying Mr. Gorman's Risk Premium analyses. Mr. Hevert also responded to Mr. Gorman's criticisms of his analyses including (1) the relevance of the ECAPM analysis; (2) the Expected Earnings approach; (3) his assessment of the Company's relative risk; and (4) the consideration of flotation costs. Lastly, Mr. Hevert responded to Mr. Gorman's analysis regarding the effect of his recommendation on the Company's financial integrity.

Mr. Hevert agreed with Mr. Gorman's observation that utilities are less risky than the broad market. At the same time, the average historical Beta coefficient for Mr. Gorman's proxy group is 0.70, suggesting a meaningful degree of risk. For example, in 2008, when the market lost about 40.00 percent of its value, the SNL Electric Company index lost about 27.00 percent of its value. In fact, from September through December 2008, when the overall market lost about 29.30 percent of its value, the correlation between the SNL Electric Company Index and the S&P 500 averaged approximately 80.00 percent. That is, when the capital markets became increasingly distressed, much like the overall market, utility valuations also decreased, although not to the same extent.

With regard to Mr. Gorman's reliance on credit rating agency reports that discuss the implications of tax reform on the utility sector, concluding they suggest the utility sector is stable

– Mr. Hevert noted that those reports discuss the uncertainties surrounding the implications of tax reform and Moody's recently placed the regulated utility industry on "Negative" outlook due to TCJA cash flow impacts and capital spending. Notably, Mr. Gorman's Figure 4 demonstrates utility capital investment has "increased considerably" and is expected to "remain high" in the 2019-2021 forecast period relative to the prior ten-year historical period. All three rating agencies observed the negative effects of the TCJA on utilities' cash flow and the potential consequences for their credit profiles. It therefore is clear that efficient access to external capital at reasonable rates will be important to fund capital expenditures, as Mr. Gorman observes. It also is clear that the markets in which that capital will be raised reflect greater volatility than those experienced even over the past two years.

Regarding Mr. Gorman's heavy reliance on the Constant Growth DCF Model, Mr. Hevert responded that the Constant Growth DCF Model is based on several underlying assumptions, including the constancy of dividend yields and P/E ratios, and those conditions currently do not hold.

With regard to Mr. Gorman's CAPM analysis, Mr. Hevert responded as follows:

- From a historical perspective, Mr. Gorman's 8.5% expected market return is well below the long-term market experience and, therefore, is not reasonable.

- Mr. Gorman's use of the historical average Market Risk Premium is unreasonable, as it should be forward-looking and all three components of the model (i.e., the risk-free rate, Beta coefficient, and the Market Risk Premium) should be consistent with market conditions and investor expectations. As Morningstar observes: "It is important to note that the expected equity risk premium, as it is used in discount rates and cost of capital analysis, is a forward-looking concept. That is, the equity risk premium that is used in the discount rate should be reflective of what investors think the risk premium will be going forward."

Mr. Hevert's principal concern with Mr. Gorman's risk premium analysis lies with Mr. Gorman's failure to apply projected utility bond yields in deriving his utility bond-based Risk Premium ROE estimates. As Mr. Gorman points out, the Cost of Equity is forward-looking. Although he applies a projected Treasury yield in calculating his 9.27% Treasury-based Risk Premium ROE estimate, he has not done the same in calculating his utility bond-based Risk Premium ROE estimates. He noted that correcting Mr. Gorman's utility bond yield-based Risk Premium estimates to reflect a forward-looking Baa-utility bond yield results in an updated ROE estimate of 9.89 percent.

Mr. Hevert noted that Mr. Gorman argues his estimated ROE is overstated and should be rejected because: (1) the Constant Growth DCF results are based on growth rates he considers unsustainably high; (2) the CAPM results assume Market Risk Premia estimates he also believes are too high; (3) the ECAPM estimates are based on a flawed method; and (4) the Bond Yield Plus Risk Premium is based on an Equity Risk Premium that, again, he finds too high. Mr. Gorman further argues the Expected Earnings approach should be rejected, that a flotation cost adjustment is not appropriate, and that the Company's business risks are captured in its credit rating. Lastly, Mr. Gorman disagrees with Mr. Hevert's assessment of the Constant Growth DCF model results.

With regard to Mr. Gorman's concerns with Mr. Hevert's proxy group, Mr. Hevert noted that Mr. Gorman adopts the proxy group used in his direct testimony, with the exception of Avangrid, Inc. ("Avangrid"). He excludes Avangrid because its ultimate parent, Iberdrola, S.A. ("Iberdrola"), owns "approximately 83%" of the company. In response, Mr. Hevert stated that Avangrid meets all of his screening criteria. Standard & Poor's and Moody's Investors Service maintain Issuer Credit ratings of BBB+ and Baa1, respectively, for Avangrid, consistent with the other companies in Mr. Gorman's proxy group. Moreover, Avangrid's risk measures, as reported by Value Line, are comparable to the companies in my and Mr. Gorman's proxy groups. Further, Mr. Hevert testified that the regulated utility operations of Avangrid Networks account for 82% of Avangrid's 2018 operating revenues, and more than 80% of its net income. Consequently, he noted, Avangrid's regulated operations represent a vast majority of total company operations. Further, he stated that Although Iberdrola owns "approximately 83%" of the outstanding common stock, Avangrid's stock price reflects the risks associated with Avangrid's operations, not Iberdrola's. On balance, Mr. Hevert continues to believe Avangrid should be included in the proxy group.

With regard to Mr. Gorman's criticism that the growth rates used in his Constant Growth DCF analysis are too high, Mr. Hevert responded that a capital appreciation rate of 5.77% (i.e., the average growth rate in the Constant Growth DCF analysis in his direct testimony) and higher has occurred quite often. In fact, the growth rates Mr. Gorman asserts are "unsustainably high" by historical standards represent approximately the 43rd percentile of the actual capital appreciation rates observed from 1926 to 2018.

With regard to Mr. Gorman's assessment of dividend yields relative to utility bond yields, Mr. Hevert does not agree that one can conclude the two are nearly identical. For example, comparing Mr. Gorman's proxy group's long-term (since 2000) average dividend yield to the average yield on the Moody's Utility A Index, the yield spread has been about 128 basis points; the current (30-day) average is 60 basis points, a difference of 68 basis points. The standard deviation, however, has been 87 basis points. Consequently, Mr. Hevert concluded, it is difficult to draw any meaningful conclusions regarding the long-term relationship between the two. Further, he stated, the difficulty in drawing conclusions based on the relationship between the two arises from the fact that debt and equity are fundamentally different securities, exposed to fundamentally different risks, acquired by investors with fundamentally different risk tolerances and return objectives. Equity investments are exposed to far more risks than are debt investments, and whereas debt investors are exposed to risks over a limited term, equity risk is perpetual. The relationship between dividend yields and interest rates therefore may be more complex than the relationship between interest rates and bond yields. For example, significant and abrupt increases in volatility often are associated with declines in Treasury yields. That relationship makes intuitive sense: As investors see increasing risk, their objectives may shift from growth to capital preservation (that is, avoiding a capital loss). A means of doing so is to re-allocate capital to the relative safety of Treasury securities in a "flight to safety". Because Treasury yields are inversely related to Treasury prices, as investors bid up the prices of bonds, they bid down the yields, such that decreases in the 30-year Treasury yield are coincident with abrupt increases in volatility, as measured by the VIX. The same may be true for debt yields, but not to the same degree. Again, debt and equity are different securities that may react to changing interest rates in different ways. In summary, given the fundamental differences between the two, Mr. Hevert does not agree that a simple comparison of bond yields to dividend yields supports the position that the DCF model currently renders reliable estimates of the Company's cost of equity.

Regarding Mr. Gorman's comparison of expected and historical dividend growth rates, the relevant issue is whether investors rely on either in pricing utility stocks. As explained below, dividend growth rates have not been statistically related to utility stock valuation levels. That finding is important because the DCF method is based on the fundamental present value formula, assuming the current market price is an accurate measure of long-term intrinsic value. That is, the Constant Growth DCF model fundamentally assumes investors use the present value structure to find the "intrinsic" value of common stock. Consequently, the DCF approach will not produce accurate estimates of the market-required ROE if the market price diverges from the present value-based estimate of intrinsic value. If dividend growth rates have no meaningful ability to explain market valuations, they should not be relied on to conclude the DCF model currently provides economically logical and reliable results. In fact, to assess the explanatory value of various measures of growth, Mr. Hevert performed a regression analysis of growth rate projections and utility P/E ratios and found projected earnings growth to be the only growth rate with a statistically strong and theoretically sound ability to explain changes in utility valuations. The results demonstrate that the only positive, statistically significant growth rate was the projected EPS growth. That is, neither DPS or BVPS growth rates, nor Sustainable Growth were directly related to valuation levels. Because dividend growth rates have no meaningful ability to explain market valuations, they should not be relied on to conclude the DCF model currently provides economically logical and reliable results, as Mr. Gorman does.

With regard to Mr. Gorman's criticism of Mr. Hevert's decision not to perform a Multi-Stage DCF analysis in this case, Mr. Hevert responded that the multi-stage model did not provide additional information relative to the analyses he did perform. Mr. Hevert pointed out that, although Mr. Gorman's position is that his Multi-Stage DCF model is "appropriate" in this proceeding, his average and median Multi-Stage DCF results of 7.28% and 7.15% are well below his recommendation of 9.00%, and it is clear Mr. Gorman did not give his Multi-Stage DCF results much weight in developing his ROE recommendation.

Mr. Hevert disagreed with Mr. Gorman's concerns with Mr. Hevert's CAPM analysis – primarily Mr. Gorman's argument that the expected market returns are "inflated" and Mr. Gorman's argument that there is a "mismatch" between Mr. Hevert's calculation of the expected market return and the projected Treasury yields. Mr. Hevert stated that the market return estimates presented in his direct testimony, which Mr. Gorman asserts are "inflated," represent the approximately 51st and 52nd percentile of actual returns observed from 1926 to 2018. Moreover, because market returns historically have been volatile, Mr. Hevert stated that his market return estimates are statistically indistinguishable from the long-term arithmetic average market data on which Mr. Gorman relies. Mr. Hevert also demonstrated Market Risk Premia of at least 12.04% (the high end of the range of the Market Risk Premium estimates in his direct testimony) occur approximately 42% percent of the time.

Regarding his "mismatch" argument, Mr. Gorman argues there is an "error" in the calculations because the risk-free rate used to calculate the market risk premium is not the same risk-free rate used in my CAPM estimates based on the near-term projected Treasury yields. Mr. Hevert noted that, despite that concern, Mr. Gorman's CAPM analysis relies on an approach analogous to Mr. Hevert's; Mr. Gorman's CAPM estimate therefore includes the same type of "mismatch" he claims is an error on Mr. Hevert's part.

Regarding Mr. Gorman's concerns with Mr. Hevert's ECAPM analysis, his primary concern is the use of adjusted Beta coefficients published by Value Line and Bloomberg estimates. Mr. Hevert responded that, as he explained in his direct testimony, the use of adjusted Beta coefficients in the ECAPM is entirely consistent with academic research, and because the ECAPM and adjusted Beta coefficients address two different aspects of security pricing it is entirely appropriate to apply both. Mr. Hevert emphasized that evidence has shown the CAPM understates the required return for companies whose Beta coefficient is less than 1.00 and overstates the return for companies whose Beta coefficient is greater than 1.00, and the ECAPM mitigates that tendency.

With regard to Mr. Gorman's criticism of Mr. Hevert's use of projected Treasury yields, Mr. Hevert responded that, although Mr. Gorman suggests current yields are a "more accurate predictor" of future yields, he has not indicated what that level of accuracy might be, or how it supports his conclusion. Mr. Hevert noted that, despite his criticisms, Mr. Gorman relies on projected Treasury yields for his CAPM and Risk Premium analyses from the same source he used (i.e., Blue Chip Financial Forecasts).

With regard to Mr. Gorman's criticisms of Mr. Hevert's bond yield plus risk premium analysis, Mr. Hevert explained that several academic studies support his findings with respect to the inverse relationship between the Equity Risk premium and interest rates. He noted his approach also is similar to the method discussed in Dr. Morin's textbook New Regulatory Finance. Mr. Hevert concluded that Mr. Gorman's concerns are misplaced – and his approach is based on sound theory, and is reflected in a model supported by published financial literature and research, and practitioner texts.

Further, although he continues to believe the Risk Premium is properly specified, Mr. Hevert performed an additional analysis to specifically include the effect of equity market volatility and credit spreads. His analysis indicated the statistically significant inverse relationship between Treasury yields and the Equity Risk Premium remains, and the resulting ROE estimates are generally consistent with those of my original and updated Bond Yield Plus Risk Premium analysis. Lastly, Mr. Hevert noted that applying Mr. Gorman's projected 2.50% 30-year Treasury yield to the alternative Bond Yield Plus Risk Premium Analysis discussed above produces an ROE estimate of 9.77% relative to Mr. Gorman's 9.00% recommendation.

Mr. Hevert next addressed Mr. Gorman's view that the expected earnings "approach does not measure the market required return…[r]ather, it measures the book accounting return." Mr. Hevert agreed that economic and financial factors, and the market-based models that depend on them are important, but those factors do not invalidate the Expected Earnings approach. Rather, no single method best captures investor expectations at all times and under all conditions. Market-based models necessarily require us to draw inferences from market data based on the assumptions and construction of methods such as the DCF and CAPM approaches, and the simplicity of the Expected Earnings approach is a benefit, not a detriment. In addition, Mr. Hevert noted that the standard revenue requirements formula applied by the Commission explicitly recognizes the validity of the book value of equity by choosing to measure capital structures based on book value, rather than market value. Moreover, he stated that although many factors affect stock returns and Market-to-Book ratios, the accounting-based ROE is one of them and therefore cannot be ignored. He testified that Dr. Morin summarizes the issue by noting that the method "is easily understood, and is firmly anchored in regulatory tradition," and concluding "because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with [Expected] Earnings, is highly meaningful." The Expected Earnings approach provides a direct measure of the expected opportunity cost of book equity. Further, because the approach looks to the expected earnings of comparable risk companies, it is consistent with the *Hope* and *Bluefield* "comparable return" standard. In Mr. Hevert's view, Mr. Gorman's argument that the Expected Earnings approach rejects the long-standing practice of setting authorized returns is without merit. Lastly, although Mr. Gorman suggests he uses the Expected Earnings approach to "place" his recommendation within my recommended range, Mr. Hevert noted that he used the approach to corroborate his recommended range.

Regarding Mr. Gorman's testimony relating to flotation costs, Mr. Hevert reiterated that flotation costs are not current expenses and are not reflected on the income statement. Rather they are part of the invested costs of the utility and are reflected on the balance sheet under "paid in capital." Whether paid directly or via an underwriting discount, the cost results in net proceeds that are less than the gross proceeds. Because flotation costs permanently reduce the equity portion of the balance sheet, an adjustment must be made to the ROE to ensure that the authorized return enables investors to realize their required return.

Regarding Mr. Gorman's evaluation of the Company's capital expenditure plan, Mr. Gorman argues Duke Energy Indiana's capital expenditure forecasts are not "out of line with the utility industry." He noted that "the industry is expected to produce more internal cash relative to projected capital expenditures during the 2022 – 2024 time period." Mr. Hevert pointed out, however, that Mr. Gorman's analysis does not compare Duke Energy Indiana to "the utility industry," or demonstrate it is consistent with the industry.

Mr. Hevert next addressed Mr. Gorman's assessment of his ROE recommendation as it affects measures of the Company's financial integrity. He noted that Mr. Gorman evaluated the reasonableness of his ROE recommendation by calculating two *pro forma* ratios – Debt to EBITDA, and FFO to Total Debt – to determine whether they would fall within S&P's guideline ranges for an investment grade rating. Based on his *pro forma* analysis, Mr. Gorman argues his recommended ROE and capital structure support Duke Energy Indiana's investment grade bond rating. Mr. Hevert testified that an important consideration is that Mr. Gorman's analysis fundamentally assumes the Company actually will earn the entirety of its authorized ROE on a going-forward basis. Moreover, Mr. Hevert pointed out that S&P's ratings process considers a range of both quantitative and qualitative data. Cash Flow/Leverage considerations are one element of a broad set of criteria. Unlike Mr. Gorman's *pro forma* analysis, S&P's assessment does not look to a single period or assume static relationships among variables. Rather, S&P reviews credit ratios "on a time series basis with a clear forward-looking bias." S&P explains that the time series length depends on a number of qualitative factors, but generally includes two years of historical data, and three years of projections. Further, the ratios depend on "base case" projections considering "current and near-term economic conditions, industry assumptions, and financial policies." Consequently, even if one assumes credit determinations fundamentally are driven by two *pro forma* metrics, the actual assessment of those metrics is far more complex than

Mr. Gorman's analysis suggests. Additionally, Mr. Hevert explained that simply maintaining an "investment grade" rating is an inappropriate standard. According to S&P, only two of 252 utilities currently have below investment grade long-term issuer ratings. Because the Company must compete for capital within the utility sector in the first instance, and with companies beyond utilities in the second, the Company must have a strong financial profile. Such a profile enables the Company to acquire capital even during constrained markets. Additionally, Mr. Hevert emphasized that relying on *pro forma* credit metrics to assess the credit implications of any specific ROE or equity ratio is a partial analysis that may lead to incorrect conclusions. That concern arises not only because the credit rating process is complex, but also because a wide range of assumed ROEs and equity ratios produce *pro forma* metrics within the benchmark ranges for a given credit rating. Mr. Hevert demonstrated that, for example, Mr. Gorman's *pro forma* analysis suggests an ROE in the range of 4.93% to 10.80% would produce *pro forma* Debt to EBITDA and FFO to Total Debt ratios in the "Significant" financial risk range identified in his analysis. That is, even if we assume an unreasonably low ROE in Mr. Gorman's analysis, the *pro forma* Debt to EBITDA ratios remain in the "Significant" financial risk range. Clearly, a return as low as 4.93 percent, which is 464 basis points below the average 2019 authorized return value of 9.57% cited by Mr. Gorman, and only five basis points above the Company's proposed embedded cost of debt, is an unrealistic estimate of the Company's cost of equity.

Mr. Hevert next addressed Mr. O'Donnell's testimony and recommendations. His principal areas of disagreement include: (1) the use of Duke Energy in Mr. O'Donnell's analyses; (2) certain aspects of Mr. O'Donnell's Constant Growth DCF analyses, particularly the growth rate component; (3) the application of the Comparable Earnings approach; (4) Mr. O'Donnell's criticisms of his application of the CAPM; (5) Mr. O'Donnell's criticisms of his Bond Yield Plus Risk Premium approach; (6) Mr. O'Donnell's concerns regarding the weight given certain model results; (7) his proposed "investment" capital structure consisting of 50.00 percent common equity and 50.00 percent long-term debt; and (8) Mr. O'Donnell's concerns regarding the Fair Value Increment.

With regard to Mr. O'Donnell's use of Duke Energy in his analyses, Mr. Hevert stated inclusion of parent companies in the proxy groups of subsidiary utilities involves circular logic. In addition, he stated, an estimate of the Cost of Equity based only on the subject company's parent runs counter to the principle of opportunity costs, which forms the foundation of the "corresponding risks" standard that Mr. O'Donnell acknowledges is critical in determining the Return on Equity.

With regard to Mr. O'Donnell's Constant Growth DCF Model, Mr. Hevert disagreed that historical growth rates are appropriate measures of expected growth. He emphasized that the growth component of the Constant Growth DCF model is a forward-looking measure, and to the extent historical growth influences expectations of future growth, it already will be reflected in analysts' consensus earnings growth estimates.

Additionally, as his explained earlier in his response to Mr. Gorman, Mr. Hevert disagreed that dividend or book value growth rates are appropriate inputs to the Constant Growth DC Model. Rather, he explained earnings growth enables both dividend and book value growth; because investors tend to value common equity on the basis of P/E ratios, the cost of equity is a function of the expected growth in earnings, not dividends or book value. In addition, he noted, Value Line is the only service relied on by Mr. O'Donnell that provides either DPS or BVPS growth projections; the fact that services such as Zacks and First Call provide earnings, but not dividend or book value growth estimates indicates that they see little investor demand for such data. As Dr. Roger Morin notes:

Casual inspection of the Zacks Investment Research, First Call Thompson, and Multex Web sites reveals that earnings per share forecasts dominate the information provided. There are few, if any, dividend growth forecasts. Only Value Line provides comprehensive long-term dividend growth forecasts. The wide availability of earnings forecast is not surprising. There is an abundance of evidence attesting to the importance of earnings in assessing investors' expectations. The sheer volume of earnings forecasts available from the investment community relative to the scarcity of dividend forecasts attests to their importance. The fact that these investment information providers focus on growth in earnings rather than growth in dividend indicates that the investment community regards earnings growth as a superior indicator of future long term growth.

Further, Mr. Hevert disagreed with Mr. O'Donnell's position that analysts' earnings growth forecasts are "unrealistically high." He noted that Mr. O'Donnell has provided no evidence that any of the growth rates used in his DCF analyses are the result of a consistent and pervasive bias on the part of the analysts providing those projections. More importantly, he emphasized, the salient issue is the growth that investors expect, not what actually happens. Additionally, he testified that the use of analysts' earnings growth projections in the DCF Model is supported by financial literature. Further, because EPS growth is the only growth rate that is both statistically and positively related to utility valuation, earnings growth is the proper measure of growth in the Constant Growth DCF Model.

Mr. Hevert also testified that he had several concerns with Mr. O'Donnell's use of the Retention Growth model. First, as discussed below, the model's underlying premise is that future earnings will increase as the retention ratio increases. However, there are several reasons why that may not be the case – such as management decisions to conserve cash, to manage the dividend payout, or to signal future earnings prospects. Mr. Hevert testified that he tested the relationship between retention ratios and future growth rates, and found that there was a statistically significant negative relationship between the five-year average earnings growth rate and the earnings retention ratio. Based on Mr. O'Donnell's own data source, earnings growth actually decreased as the retention ratio increased. In Mr. Hevert's opinion, those findings clearly call into question Mr. O'Donnell's reliance on his "Retention Growth" estimate. He noted that independent research confirms his findings.

Next, Mr. Hevert addressed the issue of negative growth rates. He pointed out that no rational investor would invest in an individual stock that is expected to decrease its earnings in perpetuity. By including negative growth rates, he stated, Mr. O'Donnell assumes investors knowingly and willingly would invest in a company that they expect to lose value every year, in perpetuity.

Mr. Hevert also discussed the structural reasons why the Constant Growth DCF Model may not always produce reliable ROE estimates – including the fact the model will not produce accurate estimates of the market-required ROE if the market price diverges from the present value-based estimate of intrinsic value. He also pointed out that investors consider other methods, including relative valuation multiples – P/E, M/B, Enterprise Value/EBITDA – in their buying and selling decisions. They do so because no single financial model produces the most accurate and reliable measure of value at all times and under all conditions. Further, the implications of market prices diverging from DCF-based estimates of intrinsic value was studied in an article published in the Journal of Applied Finance. That article, which focused on back-tests of the Constant Growth DCF model, found that even under "ideal" circumstances:

> … it is difficult to obtain good intrinsic value estimates in models stretching over lengthy periods of time. Shorter horizon models based on five or fewer years show more promise. Any model based on dividend streams of ten years or more, whether as a teaching tool or in practice, should be used with caution since they are likely to produce low-quality estimates.

In short, Mr. Hevert summarized, because the DCF model is derived from a valuation model that assumes constancy in perpetuity, it is likely to produce less reliable ROE estimates when market conditions are non-constant, and when investor practice is to consider multiple valuation methods.

Regarding his conclusions regarding the appropriate growth rate for the Constant Growth DCF Model, based on the analyses and research noted in his testimony, Mr. Hevert, concluded that projected EPS growth rates represent the appropriate measure of growth in the Constant Growth DCF model.

With regard to the Comparable Earnings method, Mr. Hevert first reiterated that, as discussed in response to Mr. Gorman, authorized ROEs have been in a relatively narrow range since 2015, with time explaining less than 0.01 percent of the variation in returns. Further, despite his concerns with Mr. O'Donnell's use of historical earned rates of return, he noted that removing Duke Energy would raise the low end of his range to at least 9.60%.

Mr. Hevert next discussed his concerns regarding the use of historical earned rates of return in the Comparable Earnings analysis. Because the Cost of Equity is inherently forward-looking, the only relevant earnings figures provided in Mr. O'Donnell's exhibits are the 2019 and 2022/2024 expected returns, and the proxy group average expected return for 2019 and 2022/2024 are 9.80 percent and 10.50 percent, respectively, 80 to 150 basis points above Mr. O'Donnell's estimate of the market required ROE. Again, Mr. Hevert emphasized, that inconsistency calls into question the relevance of Mr. O'Donnell's 9.00 percent estimate of the market required ROE and recommendation.

Additionally, while Mr. Hevert appreciates that there is a difference between market and book value, he pointed to studies that suggest that although many factors may affect stock returns and market to book ratios, the accounting-based ROE is one of them, and should not be ignored.

Lastly, Mr. Hevert pointed out that he has not suggested using the Expected Earnings approach as the sole measure of the appropriate ROE. Rather, he has used that method to corroborate the DCF, CAPM, ECAPM, and Risk Premium methods. And he noted that the results of Mr. O'Donnell's Comparable Earnings approach are similar to the results of his Expected

Earnings analysis. Mr. O'Donnell's projected earned returns produce ROE estimates of 9.60 percent and 10.50 percent for his proxy group. Those results are within the range of results in Mr. Hevert's updated Expected Earnings analysis.

With regard to the Capital Asset Pricing Model, Mr. Hevert disagreed with Mr. O'Donnell's assessment of the CAPM and other risk-premium methods. First, he noted that the relevant issue is whether investors use multiple methods, including risk premium-based approaches, in evaluating investment opportunities and making investment decisions. He pointed out that Mr. O'Donnell has not demonstrated investors would disregard those methods in favor of the Constant Growth DCF approach. And, surveys and articles indicate that CAPM is used by practitioners, and are more likely to use the CAPM than the DCF model. Mr. Hevert also emphasized that through Beta coefficients, the CAPM method addresses the *Hope* and *Bluefield* "comparable risk" standard in a way that DCF-based methods do not.

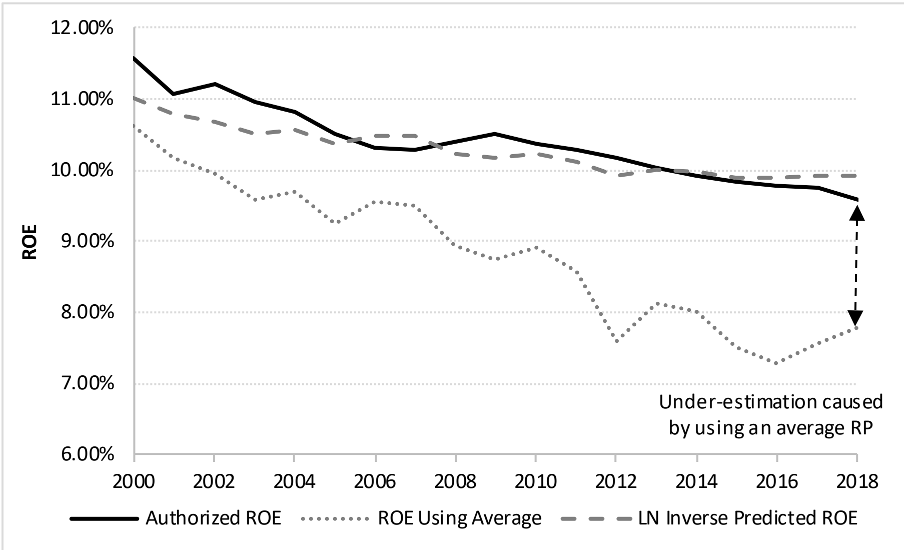
With regard to Mr. O'Donnell's criticisms of Mr. Hevert's Market Risk Premium calculations, he emphasized that the MRP is not constant over time, and can be influenced by factors such as investors' changing levels of risk aversion, or changes in interest rates. Regarding the relationship between interest rates and the MRP, he noted, academic studies found an inverse relationship between the two. Discussing that relationship, Dr. Morin notes:

> … [p]ublished studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates - rising when rates fell and declining when interest rates rose.

As such, Mr. Hevert testified, increases in the MRP coincident with declining interest rates is consistent with financial theory.

Regarding his application of the Bond Yield Plus Risk Premium method, Mr. Hevert explained that Mr. O'Donnell appeared to misunderstand the application of the model, which leads to his incorrect assertion that he has been inconsistent in his application of that approach. Further, Mr. Hevert explained an analysis he performed that demonstrates the relative accuracy of an average equity risk premium compared to a risk premium that reflects the inverse relationship between bond yields and equity risk premiums. Mr. Hevert's analysis demonstrates that applying a Risk Premium model that reflects the inverse relationship produces generally accurate estimates of observed average authorized ROEs, while Mr. O'Donnell's recommendation to use a static Equity Risk Premium produces significant errors, particularly in relatively low (or high) interest rate environments.

Accuracy of Risk Premium ROE Estimates



Next, Mr. Hevert addressed the weighting of model results and use of the Multi-Stage DCF model. Mr. Hevert emphasized the importance of using multiple methods in estimating cost of equity, noting that is well supported in literature. As Dr. Morin notes:

> Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory. The inability of the DCF model to account for changes in relative market valuation, discussed below, is a vivid example of the potential shortcomings of the DCF model when applied to a given company. Similarly, the inability of the CAPM to account for variables that affect security returns other than beta tarnishes its use.
>
> No one individual method provides the necessary level of precision for determining a fair return, but each method provides useful evidence to facilitate the exercise of an informed judgment. *Reliance on any single method or preset formula is inappropriate when dealing with investor expectations because of possible measurement difficulties and vagaries in individual companies' market data.*

Additionally, he emphasized that the weight given to any model should be based on its relevance under prevailing and expected market conditions, not on weights that may have been applied ten or more years ago, when capital markets were fundamentally different. Mr. Hevert stated that his position is consistent with the *Hope* and *Bluefield* principle that it is the analytical result, as opposed to the method employed, that is controlling in arriving at just and reasonable rates. Importantly, he testified, finance scholars make clear one should not mechanically apply models. Rather, one should choose among them based on the data at hand.

Mr. Hevert testified that Mr. Chriss did not undertake an independent, market-based analysis of the Company's cost of equity. In addition, he emphasized that the regulatory environment is one of the most important factors debt and equity investors factor in their assessment of risk. And, utility credit ratings and outlooks depend substantially on the extent to which rating agencies view the regulatory environment credit supportive, or not. Given the Company's need to access external capital and the weight rating agencies place on the nature of the regulatory environment, Mr. Hevert testified that it is important to consider the extent to which the jurisdictions that recently have authorized ROEs for electric utilities are viewed as having constructive regulatory environments. Mr. Hevert noted that across the 86 vertically integrated rate cases for which RRA reports an authorized ROE since 2016, there was a 48-basis point difference between the median return for jurisdictions ranked in the top third of all jurisdictions and jurisdictions ranked in the bottom third of all jurisdictions (the higher-ranked jurisdictions providing the higher authorized returns). As Mr. Hevert's testimony indicates, authorized ROEs for vertically integrated electric utilities in jurisdictions rated in the top third of all jurisdictions, including Indiana, range from 9.37 percent to 10.55 percent, with an average of 9.94 percent, and a median of 9.98 percent.

Vertically Integrated Authorized ROE by RRA Ranking

Authorized ROE (%) Vertically Integrated Electric Utilities			
RRA Ranking	Top Third	Middle Third	Bottom Third
Mean	9.94%	9.40%	9.63%
Median	9.98%	9.50%	9.50%
Maximum	10.55%	9.60%	11.95%
Minimum	9.37%	8.75%	9.06%

Mr. Hevert stated that his recommended range, 10.00% to 11.00%, is consistent with the returns authorized in more constructive jurisdictions. He also pointed out that Mr. Chriss' calculation of average ROEs includes Illinois formula rate plan ROEs, which biases his average downward. Finally, he testified that Mr. Chriss' recommendation ignores the financial community impact of his recommendation, and the commensurate risk that represents. the industry and the Company is no less risky relative to the proxy group.

Based on this, Mr. Hevert testified that he continues to believe the reasonable range of ROE estimates is from 10.00% to 11.00%, and within that range, 10.40% is a reasonable and appropriate estimate of the Company's cost of equity. He stated that the results of his updated Constant Growth and Quarterly Growth DCF, CAPM, ECAPM, and Bond Yield Plus Risk Premium analyses, along with the Expected Earnings results and his analyses of capital market data, authorized returns in other regulatory jurisdictions, and assessments of rating agency concerns and criteria support the reasonableness of his range of ROE estimates and his recommendation. His updated results are shown below:

Summary of Updated Analytical Results

Discounted Cash Flow	Mean Low	Mean	Mean High
30-day Constant Growth DCF	7.68%	8.50%	9.32%
90-day Constant Growth DCF	7.75%	8.57%	9.39%
180-day Constant Growth DCF	7.85%	8.67%	9.49%
CAPM Results		Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient			
Current 30-Year Treasury (2.18%)		7.45%	8.28%
Near Term Projected 30-Year Treasury (2.28%)		7.55%	8.39%
Long-Term Projected 30-Year Treasury (3.70%)		8.97%	9.80%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (2.18%)		8.22%	9.17%
Near Term Projected 30-Year Treasury (2.28%)		8.32%	9.28%
Long-Term Projected 30-Year Treasury (3.70%)		9.74%	10.69%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (2.18%)		8.22%	9.17%
Near Term Projected 30-Year Treasury (2.28%)		8.32%	9.28%
Long-Term Projected 30-Year Treasury (3.70%)		9.74%	10.69%
Empirical CAPM Results		Bloomberg Derived Market Risk Premium	Value Line Derived Market Risk Premium
Average Bloomberg Beta Coefficient			
Current 30-Year Treasury (2.18%)		8.79%	9.84%
Near Term Projected 30-Year Treasury (2.28%)		8.89%	9.94%
Long-Term Projected 30-Year Treasury (3.70%)		10.31%	11.36%
Average Value Line Beta Coefficient			
Current 30-Year Treasury (2.18%)		9.37%	10.51%
Near Term Projected 30-Year Treasury (2.28%)		9.47%	10.61%
Long-Term Projected 30-Year Treasury (3.70%)		10.89%	12.02%
	Low	Mid	High
Bond Yield Risk Premium	9.95%	9.93%	10.05%
		Mean	Median
Expected Earnings		10.35%	10.53%

vii. Commission Discussion and Findings. The U.S. Supreme Court established the guiding principles for establishing a fair return for capital in two seminal cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n* ("*Bluefield*"); and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* ("*Hope*"). In *Bluefield*, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.

The Court thus recognized that: (1) a regulated public utility cannot remain financially sound unless the return it is allowed to earn on its invested capital is at least equal to the cost of capital; and (2) a regulated public utility will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of similar risk.

In *Hope*, the Court reiterated the financial integrity and capital attraction principles of the *Bluefield* case:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. . . . By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

In summary, the Court clearly has recognized that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

Indiana precedent comports with the *Hope* and *Bluefield* principles. For example, this Commission recently stated (as it has in previous rate orders), that it has used the following standards and criteria to determine a fair rate of return on a petitioner's investment in its utility plant:

> (1) Return comparable to return on investments in other enterprises having corresponding risks;
> (2) Return sufficient to ensure confidence in the financial integrity of the petitioner;
> (3) Return sufficient to maintain and support the Petitioner's credit [rating];
> (4) Return sufficient to attract capital as reasonably required by the Petitioner in its utility business.

In re *Petition of Indiana Michigan Power Co., Cause No. 44075, at p. 47 (IURC; 02/13/2013).*

Citing the Indiana Supreme Court, the Commission noted that:

> The ratemaking process involves a balancing of all these factors and probably others; a balancing of the owner's or investor's interest with the consumer's interest. On the one side, the rates may not be so low as to confiscate the investor's interest or property; on the other side the rates may not be so high as to injure the consumer by charging an exorbitant price for service and at the same time giving the utility owner an unreasonable or excessive profit.

Id. at p. 47-48.

The Commission concluded that:

> ...the results of any return computation may be tempered by the Commission's duty to balance the respective interests involved in ratemaking. The end result of the Commission's Orders must be measured as much by the success with which they protect the broad public interest entrusted to our protection as by the effectiveness with which they allow utilities to maintain credit and attract capital.

Id. at p. 48.

Based on those standards, the ROE authorized in this proceeding should provide the Company with the opportunity to earn a fair and reasonable return, and enable efficient access to external capital under a variety of market conditions. A return that is adequate to attract capital at reasonable terms enables the utility to provide service while maintaining its financial integrity.

As discussed above, and in keeping with the *Hope* and *Bluefield* standards, that return should be commensurate with the returns expected elsewhere in the market for investments of equivalent risk. The consequence of the Commission's order in this case, therefore, should be to provide Duke Energy Indiana with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. To the extent Duke Energy Indiana is provided a reasonable opportunity to earn its cost of equity, neither customers nor shareholders should be disadvantaged. In fact, a return that is adequate to attract capital at reasonable terms enables Duke Energy Indiana to provide safe, reliable electric utility service while maintaining its financial integrity, all to the benefit of both investors and customers.

In order to meet the requirements set forth in *Bluefield* and *Hope*, the parties proposed various returns using a variety of methods as bases for their positions. Based on the entirety of the testimony presented on this issue, it is apparent that we have been presented with, in several instances, highly detailed discussions of the cost of equity capital. Among other things, our discussion and analysis of this issue serves to illustrate that the goals for setting the fair rate of return for a public utility go well beyond the use of formulas and mathematical calculations which may imply a level of precision which does not really exist. With this in mind, we turn our analysis to the cost of equity evidence submitted in this proceeding.

Many of the witnesses testifying concerning Petitioner's cost of capital used similar approaches – various types of DCF studies, the CAPM model, Risk Premium approaches, and Comparable Earnings analyses. As is typically the case, however, they came to different conclusions. Mr. Hevert's recommended range of reasonable ROEs for Petitioner is 10.00% to

11.00%, with a point recommendation of 10.40%. Mr. Garrett testified to a "true cost of equity" of 6.30%, but recommended a 9.00% ROE for Petitioner. Mr. Gorman testified to a range of ROEs from 8.50% to 9.30%, and recommended an ROE no higher than 9.00%. Mr. O'Donnell recommended an ROE of 9.00%, from a range of results from 7.25% to 10.25%. Mr. Chriss did not make a specific ROE recommendation, instead pointing to ROEs authorized in other jurisdictions.

Thus, the cost of equity calculations presented in this case range from 6.30% to 11.00% -- a range of 470 basis points, while the difference in recommended ROEs is 9.00% on the low end, and 11.00% on the high end. Notably, the non-utility parties' ranges of ROEs went from a low of 6.30% to a high of 10.25% -- almost 400 basis points. Several factors, some of which are discussed in more detail below, contributed to the variation in estimates. While we do not find it necessary to resolve each of the sometimes academic disagreements between the witnesses, we discuss below the major areas of disagreement.

At the outset, however, we note that we find Mr. Garrett's "true" cost of equity of 6.30% outside the bounds of reasonableness, as judged by both a review of recently-authorized ROEs in other cases as well as the testimony of other witnesses in this proceeding. Additionally, we note that his recommended 9.00% ROE is unsupported by any analytical evidence.

The primary areas of disagreement among the witnesses are as follows: (1) the appropriate weighting for the different methods, particularly in the current capital environment; (2) the appropriate growth rate input for the DCF model; (3) the risk-free rate input for the CAPM; (4) the Beta coefficient input for the CAPM; (5) the Equity Risk Premium input for the Risk Premium model; (6) the time period in which to consider Comparable Earnings; (7) the propriety of reflecting flotation costs; (8) the importance of company-specific risks; and (9) the importance of maintaining financial integrity of the utility.

With regard to the weight to be given the various models, we continue to believe that each approach is useful and should be considered. However, we are persuaded that Mr. Hevert is correct in his recommendation that we give relatively less weight to the Constant Growth DCF results in the current capital market environment. As the evidence makes clear, all of the witnesses' DCF results are markedly below what we and other regulatory commissions have recently found to be reasonable estimations of the cost of a utility's equity. For example, Mr. Gorman's DCF results range from 7.15% to 8.61%, and he effectively gives little weight to these results in reaching his recommended ROE. Similarly, Mr. Garrett calculates a cost of equity of 6.90% based on his DCF analyses, a result which is markedly below any recently-authorized utility ROEs.

We note that in 2018, the FERC found that "in light of current investor behavior and capital market conditions, relying on the DCF methodology alone will not produce a just and reasonable ROE." And in its July 2017 Order Accepting Stipulation in which it authorized a 9.90% ROE for Duke Energy Carolinas, the North Carolina Utilities Commission noted it "carefully evaluated the DCF analysis recommendations" of the ROE witnesses (which ranged from 8.45 percent to 8.80 percent) and determined that "all of these DCF analyses in the current market produce unrealistically low results." The fundamental structure of the Constant Growth DCF model assumes constancy in perpetuity, which is simply not compatible with the recent and current capital markets and economic environment. Accordingly, we conclude that we should give relatively less weight to the Constant Growth DCF model. Notably, this conclusion is consistent with our longstanding view that the cost of equity cannot be precisely calculated and estimating it requires the use of judgment; due to this lack of precision, the use of multiple methods is desirable because no single method will produce the most reasonable result under all conditions and circumstances.

Within the context of our consideration of the DCF model, we are persuaded that Mr. Hevert's growth rate assumptions are the most reasonable. Mr. Hevert's growth rate estimates are based on analysts' growth rate estimates, which are both forward-looking and relied upon by investors. Our task in estimating cost of equity is focused on returns required by investors, which in turn is focused on investors' expectations. The other parties' growth rate inputs, on the other hand, ignore investor expectations and requirements, and are artificially low – constrained by, for example, the rate of inflation or GDP or service territory load growth. However, a utility's growth is not so constrained. As Mr. Hevert put it, there is not a direct path from retail sales growth to earnings. Rather, as a regulated entity with an obligation to serve, and an obligation to provide reliable service, a utility's growth is driven to some extent not by inflation or GDP or load growth, but rather, by capital investments needed to meet its obligation to provide reliable service to all customers.

With regard to the risk-free rate input for the CAPM, we agree with Mr. Hevert that because the cost of equity is forward-looking, it also is important to reflect forward-looking expectations of the risk-free rate. We also agree that the risk-free rate assumption should reflect the fact that utility equity is a long-term investment. Accordingly, we agree with his use of two different measures of the risk-free rate in the CAPM analysis: (1) the current 30-day average yield on 30-year Treasury bonds; and (2) the near-term projected 30-year Treasury yield. As Mr. Hevert testified, the 30-year Treasury yield best matches the life of the underlying investment – because electric utility securities are typically long duration investments.

With respect to the Beta coefficient input for the CAPM, we agree with Mr. Hevert: the evidence and academic experts indicate the CAPM tends to underestimate returns for low-Beta coefficient firms. As Mr. Hevert explained, the ECAPM adjusts for the CAPM's tendency to under-estimate returns for companies that (like utilities) have Beta coefficients less than one, and over-estimate returns for relatively high-Beta coefficient stocks. The ECAPM recognizes the results of academic research indicating that the risk-return relationship is different (flatter) than estimated by the CAPM. We note that, as Dr. Roger Morin has stated, the ECAPM is "a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. . . . Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. . . . [T]he ECAPM is a return [] adjustment and not a beta [] adjustment. Both adjustments are necessary." Because the ECAPM mitigates the drift in Beta coefficients, we agree it is a reasonable method to use, and we find that Mr. Hevert's use of the ECAPM and his Beta coefficient inputs are reasonable.

We next address the Equity Risk Premium input for the Bond Yield Plus Risk Premium model. We conclude that Mr. Hevert's position that the Equity Risk Premium varies inversely to interest rates is reasonable, based on his statistical analysis and the strength of their results. We agree authorized ROEs reflect the market data and methods used by investors, and are proper inputs to the model. We further agree that because the Cost of Equity is forward-looking, it is appropriate to use projected Treasury yields in the analysis. Those inputs produce reasonable estimates of the cost of equity.

With regard to the time period in which to consider Comparable Earnings, we share Mr. Hevert's concerns regarding the use of historical earned rates of return in the Comparable Earnings analysis, due to the fact the cost of equity is inherently forward-looking. We agree with Mr. Hevert that, using future expected returns supports Mr. Hevert's assumption much more than it does other witnesses, such as Mr. O'Donnell.

With respect to flotation costs, the evidence demonstrates that they are real costs, necessarily incurred in a utility's acquisition of equity capital. Just because they do not show up in an invoice does not mean they are not real costs, as suggested by Mr. Garrett. The fact is, the utility receives less in proceeds than the equity it issues, due to flotation costs. Those costs are a permanent reduction to common equity and absent recovery of them, the utility would not be able to earn its required return. We note that in this case, Mr. Hevert did not make a specific adjustment for flotation costs, but rather, used its existence to support his recommended cost of equity.

Next we consider the importance of considering company-specific risks in our cost of equity analysis. Mr. Garrett urges us to ignore company-specific risks entirely, arguing that investors do not consider anything other than systemic business risk. Mr. O'Donnell argues that rather than being a risk, the Company's heavy reliance on coal, and the concomitant environmental challenges presented by that reliance, are in fact a plus – in the form of an "investment opportunity" – rather than a risk. Mr. Gorman argues any such risks are reflected in credit ratings. Mr. Hevert, on the other hand, persuasively argues that the Company faces risks that other utilities and other companies do not, such as a heavy reliance on coal, environmental challenges that flow from that heavy reliance on coal, power market volatility risks that put its revenues at risk, and the Company's significant capital financing plan for the next few years. Mr. Hevert also addressed the risk mitigation associated with various rate mechanisms the Company has in place, concluding that the types of rate mechanisms the Company has in place are now widespread and available to numerous utilities. We agree with Mr. Hevert that company-specific risk is highly relevant to the determination of cost of equity. The financial community pays close attention to regulation when it rates specific utility companies, and their analyses influence investment decisions. In this case, as a heavily reliant coal utility participating in a volatile power market, with serious environmental compliance requirements and challenges, and substantial capital expenditure needs, Duke Energy Indiana is facing risks that many other utilities simply do not face. Additionally, we recognize and agree with Mr. Hevert that the rate mechanisms the Company has in place do not set it apart from other utilities. Even the decoupling proposal (which we discuss later in this Order) is no longer unique. Accordingly, we agree with Mr. Hevert that it is important that we qualitatively consider the company-specific risks when determining Duke Energy Indiana's cost of equity. On balance, these company-specific risks support an ROE at the higher end of a reasonable range of ROEs for Duke Energy Indiana.

We would also be remiss if we did not also consider the importance of the utility's financial integrity when making our cost of equity determination. Again, as Mr. Sullivan and Mr. Hevert both testified, Duke Energy Indiana faces significant risks and a substantial capital program over the next few years. We note that Mr. Sullivan testified that Duke Energy Indiana's capital requirements are expected to be funded from internal cash generation, the issuance of debt, and equity funding, while also meeting dividend obligations to its shareholders. Both Mr. Sullivan and Mr. Hevert also testified that it is important, and beneficial, to customers that the Company be able to finance needed investments on reasonable terms. Indeed, *Hope* and *Bluefield* and Indiana precedent require us to take actions to maintain utilities' financial integrity.

We find Mr. Gorman's *pro forma* assessment of Duke Energy Indiana's financial integrity unpersuasive. We agree with Mr. Hevert that rating agencies' assessments of credit ratings go far beyond calculating two *pro forma* credit metrics. There is no doubt credit rating determinations consider a broad range of factors; those considerations and factors are greater in number and far more complex than Mr. Gorman's analysis suggests. We agree with Mr. Hevert that a broad range of ROE assumptions meet the *pro forma* credit metrics Mr. Gorman argues would support Duke Energy Indiana's credit rating. As Mr. Hevert noted, an ROE of 4.93% would produce Debt/EBITDA and FFO/Debt ratios in the same range as Mr. Gorman's 9.00% ROE recommendation, and Mr. Hevert's 10.40% recommendation. Such a broad range of results casts considerable doubt on the analysis' usefulness. Accordingly, we give Mr. Gorman's financial integrity analysis no weight in arriving at Duke Energy Indiana's ROE.

Given the foregoing, we conclude and find that Petitioner's proposed cost of equity of 10.40% is reasonable and should be approved. Our finding is supported not only by our analysis and findings concerning the ROE methodologies, inputs, and assumptions, but also by our view that the DCF method should be given relatively less weight, our view that the ECAPM method should be given consideration, our view that Duke Energy Indiana's company-specific risks are relevant and support an ROE at the higher end of a reasonable range of ROEs, and evidence of the need for the Company to maintain financial integrity in light of substantial near-term capital financing needs.

Accordingly, for purposes of this Cause, we find that Petitioner's overall cost of capital is 6.00%, computed as follows:

Description	**Capitalization (in thousands)**	**Ratio**	**Cost**	**Weighted Cost**
Common Equity	$ 4,770,344	40.98%	10.40%	4.26%
Long Term Debt (estimated)	4,228,373	36.33%	4.50%	1.63%
Deferred Income Taxes	2,447,756	21.03%	0.00%	0.00%
Unamortized ITC – Crane Solar	10,999	0.09%	7.62%	0.01%
Unamortized ITC -- 1971 & Later	1,955	0.02%	7.62%	0.00%
Unamortized ITC – Advanced Coal (IGCC)	133,500	1.15%	7.62%	0.09%
Customer Deposits	47,056	0.40%	2.00%	0.01%
Total	$ 11,639,983	100.00%		6.00%

11. Forecasted Operating Income at Present Rates and *Pro Forma* Adjustments.

a. General. For the forecasted test period ending December 31, 2020, Duke Energy Indiana's total company operating income from its electric utility operations on an ongoing level basis, was shown by Petitioner to be as follows:

$ in Millions under current rates	2020
Total Operating Revenues	2,927
Operating Expenses	
Fuel & Purchased Power Expense	884
Operation and Maintenance	796
Depreciation and Amortization	564
Property and other Taxes	92
Income Taxes	76
Total Operating Expenses	2,412
Operating Income	515

b. Undisputed *Pro Forma* Adjustments. Petitioner proposed a number of undisputed *pro forma* adjustments to its operating income in its forecasted test period results. It proposed other adjustments that, though disputed at some point in the process of this rate case, were compromised or were no longer in dispute at the conclusion of the evidentiary hearing in this Cause. All such *pro forma* adjustments proposed by Petitioner, either as originally proposed and undisputed, or as compromised with the compromised positions having been fully identified by the parties, are hereby accepted even though they may not be specifically discussed in this Order. Note that these undisputed *pro forma* adjustments that we are approving include the agreement reflected in Mr. Jacobi's and Ms. Sieferman's rebuttal testimony to reduce Account 575 expense by $2.0 million. We note also that Petitioner proposed, and no party disputed, that its base cost of fuel should be 26.955 mills per kWh.

c. Disputed *Pro Forma* Adjustments. In making our determinations regarding an appropriate level of forecasted operating expenses to be used in setting Petitioner's rates, we are guided by our overall objective of achieving a level of expenses which are representative of probable future experience. The Indiana courts have emphasized the importance of viewing test year results and *pro forma* adjustments in the context of estimating a representative ongoing level of utility expenses. *See, e.g., City of Evansville v. Southern Indiana Gas & Electric Co.*, 167 Ind. App. 472, 339 N.E.2d 562, 575, in which the Court stated that: "The theory underlying the use of any test year and of any adjustment method in the rate-making process demands that the data used provide an accurate picture of the utility's operations during the period in which the proposed rates will be in effect." With this guidance in mind, we turn to an examination of the disputed *pro forma* revenue and expense adjustments at issue in this case.

i. Load Forecast and Unbilled Revenues.

(A) Petitioner's Evidence. Mr. Jacobi testified in his direct testimony how he used in the Company's load forecast in the development of its financial forecast for 2020, which in turn forms the basis for the Company's requested revenue requirement in this case. Ms. Graft testified concerning a *pro forma* adjustment that removes $28,853,000 from test period revenues for unbilled revenues that are properly excluded from the development of new base rates. She stated that unbilled revenues represent the estimated amount of revenues associated with electric utility service the Company has provided but not yet billed to customers. She further stated that the Company bases the calculation of its revenue deficiency in a rate case on billed revenues only.

(B) OUCC's Evidence. The OUCC raised two load forecast-related issues, relating to: (1) unbilled revenues; and (2) the residential energy use forecast. With regard to unbilled revenues, OUCC witness Kollen recommends that the Commission reject the Company's *pro forma* adjustment removing its unbilled revenues. He stated that the Company's revenues should reflect the forecast sales in the year, not the billed sales, which lag the actual sales each month and should reflect the same unbilled revenues methodology that the Company uses for financial reporting. He added that the billed revenues methodology understates the sales and revenues in the test year and creates a fundamental mismatch between the test year for revenues (approximately mid-December 2019 through mid-December 2020) compared to the approved 2020 calendar year test year used for the Company's costs (rate base, expenses, and capitalization). Further, he testified that it is inappropriate to restate revenues to reflect sales in a period other than the test year.

With regard to the residential sales forecast, OUCC witness Watkins testified that the Company's forecasted KWH sales and attendant revenues for residential customers used for ratemaking purposes (both for class cost of service purposes as well as actual rate design purposes) are significantly understated. Mr. Watkins testified that the Company based its energy sales forecast on a Fall 2018 load forecast, as opposed to an updated Spring 2019 load forecast. He noted that the Company's Fall 2018 forecast is significantly lower than forecasted amounts for 2020, either in prior forecasts (Fall 2017 and 2016 forecasts), or in the more recent Spring 2019 forecast. He also stated on a weather-normalized basis, historical residential sales during the period 2016 through 2018 have been significantly higher than the Company's forecasted residential energy sales used for ratemaking purposes in this case. Mr. Watkins proposed an adjustment to the forecasted residential energy sales based upon an average weather-normalized usage from 2016-2018 and based upon the Spring 2019 forecasted number of customers. He then allocated his adjusted forecast of residential energy sales to individual rate schedules using the same allocation as used by Mr. Bailey, and converted his adjusted forecast to residential revenues at current rates.

(C) Petitioner's Rebuttal Evidence. Ms. Graft and Mr. Bailey responded to the OUCC's position on unbilled revenues. Ms. Graft reiterated that the Company bases the calculation of the revenue deficiency in a rate case using a forecasted test period on billed revenues only. She stated that this ensures alignment with the sales volumes used in rate design, which are also on a billed basis. Additionally, she stated, proposed revenues (which are the basis for proposed rates) are equal to the sum of proposed net operating income (return on investment) plus proposed operating expenses. In other words, she emphasized, unbilled revenues do not impact the calculation of proposed revenues. Mr. Bailey similarly testified that the rate design process utilized a historical billing period predicated on billing cycle data. He stated that this data was then used to apportion the forecast to rate schedules, as well as the blocking for applicable rates, then used to compute present revenue. He testified that the forecast is computed based on a billing cycle basis as well. Finally, he testified, the total proposed revenue requirement was developed without unbilled revenue. Thus, he summarized, while unbilled revenue may have some relevance to certain accounting computations, it has no bearing on the final revenue requirement, nor the computation of the Company's final rate designs. Accordingly, he concluded excluding unbilled revenue from the revenue requirements and rate design is proper ratemaking.

In response to a docket entry question from the Commission, the Company explained the substantially higher level of the unbilled revenues at issue, compared to a year earlier. The Company's docket entry response summarized the volatility in unbilled revenues and the drivers of unbilled revenues, and explained that while unbilled sales were likely overstated slightly, this was the result of a very minor growth rate assumption. The Company's response concluded that a more reasonable estimate of unbilled revenues would range from about a negative $5 million to positive $12 million instead of $28 million. As a final point, the Company's response to our docket entry question emphasized that the forecasted $28 million in unbilled revenues has no effect on the Company's revenue requirement: "The Company identified a level of revenues required to cover its costs identified in the cost of service. In the event unbilled revenues were to be included, it would only impact the identified level of present revenues and should not be included in rate design as indicated in Mr. Bailey's rebuttal testimony."

Company witness Stillman responded to Mr. Watkins' concerns that the Company's forecasted kWh sales and therefore revenues for residential customers are understated. Mr. Stillman testified that the Company has updated the forecast twice since the Fall 2018 forecast, and the most current forecast shows that expected 2020 retail billed sales come in slightly below what was originally assumed in the Fall 2018 forecast. His testimony showed actual billed sales for 2014 through 2019, which demonstrated that 2018 billed sales was an outlier, growing by almost 33 GWh whereas the Company had experienced sales declines in previous periods. Mr. Stillman stated that the unusual growth experienced in 2018 is thought to be the result of the fiscal stimulus, brought on largely by the 2017 Tax Cut and Jobs Act. Mr. Stillman stated that this provided a short-term stimulus, prompting business investment and growth across most classes. However, he testified, that stimulus was short lived, and sales going forward are more likely to follow the trend in sales seen since 2014. Unfortunately, he stated, the growth experienced in 2018 influenced the Company's Spring 2019 forecast and caused the Company to overestimate forecasted sales in that study.

Mr. Stillman also showed that the residential use per customer used in this proceeding is relatively close to what is expected in the Company's most recent forecasted results. He testified that the unusual 2018 results impact Mr. Watkins' calculations and cause him to overstate both his assumed 2020 use per customer, as well as his estimated 2020 MWH sales. Mr. Stillman added that, by using a simple average, Mr. Watkins fails to incorporate the long-standing trend of energy efficiency adoption. Mr. Stillman testified that usage per customer is dropping approximately 1.3% a year during both four-year periods of 2014 to 2018, and 2015 to 2019. He noted that if Mr. Watkins had simply incorporated this trend in his calculation, his average usage of 12,497 kWh/customer would actually be 12,016 kWh/customer by 2020. Mr. Stillman concluded his testimony by stating that in his experienced opinion, the forecast used by the Company in this proceeding is still reasonable in terms of kWh sales.

(D) <u>Commission Discussion and Findings</u>. Addressing the unbilled revenues issue first, we are persuaded that the Company's exclusion of unbilled revenues from its calculations is reasonable. The evidence shows that the Company's rate calculations make no use of unbilled revenues, either in the calculation of proposed revenue requirements or in the design of rates. The evidence also indicates that the $28 million in unbilled revenues at issue is likely overstated. We note that this Commission has previously found that unbilled revenues need not be used to calculate revenue requirements or rates. In the Order in Cause No. 43090, we disagreed with the OUCC's proposal to include unbilled revenues in *pro forma* revenue requirements, stating: "As Lawrenceburg's witness Kerry Heid pointed out, by consistently accounting for revenues based on the Utility's billing cycle, the actual billing volumes are synchronized with the full twelve months of revenues, which is critical for rate design purposes. Therefore, the Commission disagrees with the OUCC's proposed adjustment to the unbilled revenue." *In re Lawrenceburg Gas Co.*, Cause No. 43090 (IURC; 06/20/2007), at page 4. Accordingly, we reject the OUCC's proposal to include unbilled revenues in the calculations of rates in this proceeding.

With regard to the issue of forecasted residential sales, the balance of the evidence shows that the residential sales forecasted used by the Company in this case is reasonable. The Company's forecast used to develop rates for this case is supported by its most recent updated load forecast (circa Fall 2019). Additionally, the evidence shows that the residential sales forecast relied upon by the OUCC to support its proposed adjustment is an outlier, the result of a short-term stimulus effect of the Tax Cut and Jobs Act. Further, even aside from this, the evidence shows that the OUCC's proposed adjustment is not reasonable, as it is based on historical averages and ignores the significant impact of energy efficiency on residential sales. Accordingly, we reject the OUCC's proposed adjustment to the residential sales forecast numbers.

ii. Depreciation.

(A) Depreciation Rates and Expense.

(I) Petitioner's Evidence. Mr. Spanos, a longstanding depreciation expert, presented and supported a depreciation study related to Duke Energy Indiana's electric plant as of December 31, 2018, as well as a fair value study. He testified that depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation, against which the Company is not protected by insurance. He stated that among the causes to be given consideration are wear and tear, decay, action of the elements, obsolescence, changes in the art, changes in demand and the requirements of public authorities. He testified that in preparation of his study, he followed generally accepted practices in the field of depreciation and valuation. He testified that his recommended depreciation rates appropriately reflect the rates at which the costs of Duke Energy Indiana's assets are being consumed over their useful lives, and that the rates are an appropriate basis for setting electric rates in this matter and for the Company to use for booking depreciation and amortization expense going forward.

He testified the purpose of the depreciation study was to estimate the annual depreciation accruals related to electric plant in service for ratemaking purposes and determine appropriate average service lives and net salvage percentages for each plant account. He stated that in preparing his study, he used the straight line remaining life method of depreciation, with the equal life group procedure for all plant assets except some general plant accounts. He stated the annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and rational manner. He testified that for certain General Plant Accounts, he used the straight line remaining life method of amortization. He explained that the annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

To determine his recommended annual depreciation accrual rates, in the first phase of his study, he estimated the service life and net salvage characteristics for each depreciable group -- each plant account or subaccount identified as having similar characteristics. Then in the second phase of his study, he calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

He explained that in the first phase of the study he compiled historic data through 2018 from records related to Duke Energy Indiana's plant; analyzed these data to obtain historic trends of survivor and net salvage characteristics; obtained supplementary information from Duke Energy Indiana's management, and operating personnel concerning practices and plans as they relate to plant operations; and interpreted the above data and the estimates used by other electric utilities to form judgments regarding average service life and net salvage characteristics. To analyze the service life data, he used the retirement rate method and applied the retirement rate method to each different group of property in the study. He explained that the retirement rate method produces an original survivor curve for that property group, and that interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. He explained that widely used Iowa-type survivor curves were used to perform the interpretations. He further testified that he used the life span technique, which has been used previously for Duke Energy Indiana, to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated.

He testified that Duke Energy Indiana provided the production facility life span estimates based on informed judgment that incorporates factors for each facility such as the age, use, size, nature of construction, and technology of the facility; management plans and outlook for the facility; the estimates for similar facilities for other utilities; and the results of the Company's 2018 IRP. Duke Energy Indiana witness Mr. Keith Pike discusses the life span estimates in detail, as is discussed below. Mr. Spanos also stated that he made a field review of Duke Energy Indiana's property during November 2018 to observe representative portions of plant and that he also made field visits during prior studies since 1999. He explained that field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. He added that because he customarily conducts field reviews for his depreciation studies, he has had the opportunity to visit scores of similar plants and meet with operations personnel at other companies, and the knowledge accumulated from those visits and meetings provides him useful information that he can draw on to confirm or challenge his analyses concerning plant condition and remaining life estimates. He opined that, drawing upon that experience, his opinion is that the estimated life spans for production facilities, as provided by Duke Energy Indiana and used in the depreciation study, are reasonable and consistent with life spans of similar facilities currently being experienced by other utilities in the industry.

He next discussed net salvage -- a component of the service value of capital assets that is recovered through depreciation rates. He explained that the service value of an asset is its original cost less its net salvage, and net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. He stated that when the cost to retire exceeds the salvage value, the result is negative net salvage.

He testified that inasmuch as depreciation expense is the loss in service value of an asset during a defined period, (*e.g.* one year), it must include a ratable portion of both the original cost and the net salvage. That is, he stated, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost and the net salvage value.

He testified that the net salvage percentages estimated in the depreciation study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data; information provided by the Company's operating personnel; general knowledge and experience of industry practices; and trends in the industry in general. He stated that the statistical net salvage analyses incorporate the Company's actual historical data for the period 1989 through 2018 and consider the cost of removal and gross salvage ratios to the associated retirements during the 30-year period. He explained that the net salvage percentages for generating facilities were based on two components: the interim net salvage percentage, and the final net salvage percentage. He stated that the interim net salvage percentage was determined based on the historical indications from the period 1989 to 2018 of the cost of removal and gross salvage amounts as a percentage of the associated plant retired. He stated that the final net salvage, or decommissioning and dismantlement component, was determined based on the retirement activities associated with the assets anticipated to be retired at the concurrent date of final retirement. He testified that the decommissioning or dismantlement component has been included in the net salvage percentage for steam, hydro and other production facilities; the decommissioning and dismantlement component is part of the overall net salvage for each location within the production assets. He stated that based on studies for other utilities and the cost estimates of Duke Energy Indiana, it was determined that the decommissioning or dismantlement component for steam, hydro, and other production facilities is best calculated by dividing the decommissioning or dismantlement cost by the surviving plant at final retirement. He explained that these amounts at a location basis are added to the interim net salvage percentage of the assets anticipated to be retired on an interim basis to produce the weighted net salvage percentage for each location.

He testified that the decommissioning or dismantlement cost estimates are based on the decommissioning study of each generating site performed by Burns and McDonnell (discussed below). He explained that these estimates are based on the current cost (year 2018 dollars) to decommission the facilities. He noted, however, that the costs to decommission power plants have tended to increase over time (as have construction costs in general). For this reason, he testified, in order to recover the full decommissioning costs for each site, these costs need to be escalated to the time of retirement.

After Mr. Spanos estimated the service life and net salvage characteristics for each depreciable property group, he then calculated the annual depreciation accrual rates for each depreciable group based on the straight line remaining life method, using remaining lives weighted consistent with the equal life group procedure. He stated that the calculations of annual depreciation accrual rates were developed as of December 31, 2018. He explained that the straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life. He testified that in the equal life group procedure, the property group is subdivided according to service life -- that is, each equal life group includes that portion of the property which experiences the life of that specific group. He stated that the relative size of each equal life group is determined from the property's life dispersion curve. He explained that this procedure eliminates the need to base depreciation on average lives, inasmuch as each group is equivalent to a unit having a single life. The full costs of short-lived units are accrued during their lives, he stated, leaving no deferral of accruals required to be added to the annual costs associated with long-lived units. The calculated depreciation for the property group is the summation of the calculated depreciation based on the service life of each equal life group, according to Mr. Spanos.

Mr. Spanos testified that the equal life group procedure allocates the capital cost of a group property to annual expense in accordance with the consumption of the service value of the group. He added that the more timely return of plant investment accomplished by fully accruing each item's cost during its service life not only reduces the risk of incomplete capital recovery, but also results in less investment-related cost over the life span of a depreciable group. He explained that under the equal life group procedure, the future book accruals (original cost less book reserve) for each vintage are divided by the composite remaining life for the surviving original cost of that vintage, and the vintage composite remaining life is derived by summing the original cost less the calculated reserve for each equal life group and dividing by the sum of the whole life annual accruals.

Mr. Spanos stated that amortization accounting is used for accounts with a large number of units, but small asset values. In amortization accounting, he explained, units of property are capitalized in the same manner as they are in depreciation accounting; however, depreciation accounting is difficult for these assets because periodic inventories are required to properly reflect plant in service. Consequently, he stated, retirements are recorded when a vintage is fully amortized rather than as the units are removed from service -- that is, there is no dispersion of retirement; all units are retired for depreciation purposes when the age of the vintage reaches the amortization period. He emphasized that amortization accounting is only appropriate for certain Common and General Plant accounts – in this case, for plant accounts which represent approximately one percent of depreciable plant.

Mr. Spanos testified that the development of the book reserve for each location has been established based on a composite rate for a group of locations within an account; thus, the actual book reserve at the location level was determined by applying a composite rate to the plant balance. He explained that when dealing with group depreciation there are multiple parameters that affect the rate, such as interim survivor curve, probable retirement date and net salvage percent among the key factors. He further explained that in conducting a depreciation study, a more defined manner of determining the individual location rates should be established. He testified that these key factors or parameters establish the theoretical reserve which is utilized to appropriately assign the book reserve at the location and vintage level. He noted that updating retirement dates adjusts the weighting between the locations; therefore, a changed retirement date, survivor curve or net salvage percent for one location affects all the locations in the account.

Mr. Spanos next addressed depreciation rates for Duke Energy Indiana's new solar generation assets planned by year-end 2019. He explained that the rates for these assets will be based on interim survivor curves for each account, a negative net salvage percent for some of the accounts, and a 25- year life span for all assets at the location. He stated that an estimated rate for new battery storage assets in Account 363 was also prepared.

Mr. Spanos testified concerning his fair value study. He explained that his study segregated the property by plant account consistent with the depreciation study and Company accounting system. More specifically, he first determined the Reproduction Cost New ("RCN") for the property in service at December 31, 2018, by trending the original cost and then deducting depreciation to arrive at the Reproduction Cost New Less Depreciation ("RCNLD"). He explained that for the property for which he determined the trended original cost, he used cost indexes. He calculated the RCN of the Company's electric plant in service as of December 31, 2018, to be $27,218,507,545; and he calculated the RCNLD of the Company's electric utility plant in service as of December 31, 2018 to be $11,633,493,162, which is 43% of the Reproduction Cost New. Mr. Spanos also provided the same fair value study information using the Company's forecasted electric utility plant in service as of December 31, 2020. He testified that it was calculated using the same methodology as his 2018 study and that the RCN of the Company's electric plant in service as of December 31, 2020, is $28,967,368,703 and the RCNLD is $12,054,723,694.

Company witness Mr. Jeffery Kopp sponsored the decommissioning study prepared by Burns & McDonnell for this proceeding. Mr. Kopp explained why it is necessary to demolish a generating station at the end of useful life, citing reuse of land, public safety, and environmental remediation of potential health hazards. The decommissioning study provided an estimated total cost, in 2018 dollars, of decommissioning and dismantling each Company-owned generation unit at the end of its useful life, as well as the total cost of decommissioning and dismantling the common facilities at these generating plants. The total decommissioning and dismantlement cost as determined by Burns and McDonnell and reflected in the Decommissioning Study, was net of salvage value for scrap materials at each plant. In general, the study assumed that each generating site would be restored to a condition appropriate for industrial use. This means that all sites will have above grade buildings and equipment removed, foundations removed to two feet below grade, be rough graded, and seeded. Sites also will have small diameter underground pipes capped and abandoned in place. Mr. Kopp explained that each of Duke Energy Indiana's electric generating plants was evaluated, including steam, hydro and other facilities, including solar and that the Burns & McDonnell team visited all plants for which site-specific decommissioning and dismantlement cost estimates were prepared. Mr. Kopp described the types of costs included in the decommissioning study and how the estimates for the direct costs were developed using a bottoms-up cost estimating approach. He explained how scrap values were determined and the necessity of including project indirect costs in the estimate, as well as the determination of the indirect costs included. He further explained that contingency costs had been included in the estimate, and that a contingency cost accounts for unspecified but reasonably expected additional costs to be incurred by the Company during the execution of decommissioning and dismantlement activities and contingency. He explained that these costs are in addition to the direct costs associated with the base decommissioning and dismantlement known scope items and that application of contingency is not only appropriate, but also standard industry practice. He further explained that Duke Energy Indiana provided estimated remaining M&S inventory balances for inclusion in the Decommissioning Study, with a portion of the inventory given a salvage credit to reflect potential reuse or resale of remaining M&S. The estimated total net decommissioning and dismantlement cost for Duke Energy Indiana's generation facilities included in the study is $420,569,400 in 2018 dollars. Mr. Kopp stated that the estimates used in the study were carefully prepared using standard and accepted estimating techniques and the best information available, and are consistent with Burns & McDonnell's industry experience. He stated that assumptions used were reasonable and that the inclusion of remaining M&S balance in the decommissioning and dismantlement costs is also reasonable, as maintaining an adequate inventory of M&S for the operation and maintenance of the generating units up to their end of life represents a prudently incurred cost for providing service to customers.

(II) **<u>OUCC's Evidence</u>.** OUCC witness Garrett testified that he employed a depreciation system using actuarial plant analysis to statistically analyze the Company's depreciable assets and develop reasonable depreciation rates and annual accruals. In contrast to Mr. Spanos' use of the Equal Life Group ("ELG") procedure, Mr. Garrett recommends the calculation of depreciation rates under the Average Life Group ("ALG") procedure. He also proposed adjustments to the Company's proposed terminal net salvage rates. More specifically, Mr. Garrett testified that the OUCC's proposed depreciation adjustments comprise several key issues: (1) calculating rates under the ALG method; (2) removing contingency costs from Duke Energy Indiana's decommissioning cost estimates; (3) removing inventory costs from Duke Energy Indiana's decommissioning cost estimates; (4) removing escalation factors from Duke Energy Indiana's terminal net salvage calculations; and (5) adjusting the Company's proposed service lives for several of its transmission and distribution accounts. During cross-examination, Mr. Garrett testified that he did not make a field visit prior to completing his depreciation recommendations.

Mr. Garrett testified that depreciation rates calculated under the ELG procedure for a particular vintage group of property will be higher in earlier years relative to later years, citing to [Wolf] and the National Association of Regulatory Utility Commissions ("NARUC") as support for his testimony. In contrast, he stated, depreciation rates calculated under the ALG procedure for a particular vintage group of property will be the same each year. Further, he testified that in order for depreciation rates calculated under the ELG procedure to be accurately applied, a utility's depreciation rates would need to be adjusted each year to reflect the decreasing depreciation rates for applicable account. He stated that under the ELG procedure, as proposed by Duke Energy Indiana, the Company's accelerated depreciation rates would simply be applied each year until the next depreciation study is filed, regardless of the fact that depreciation rates should decrease annually during that time under the ELG procedure. He testified that this arrangement does not result in a systematic and rational cost recovery mechanism, and, by proposing depreciation rates under this scheme, Duke Energy Indiana has failed to meet its burden to make a convincing showing that its proposed depreciation rates are not excessive.

He stated that, in theory, the ELG could be part of a systematic and rational cost recovery system. In practice, however, it would be difficult to come to the same conclusion, because in order for the ELG procedure to be properly applied, a utility would need to revise depreciation each year. However, he stated, given the logistical realities involved with prosecuting rate cases, this would be impractical and inefficient. He further testified that when a utility has made substantial, recent capital investments, depreciation expense calculated under the ELG method will always be higher than the expense calculated under the ALG method; the larger the amount of the investments, the larger the discrepancy will be between the two procedures. He attributed utilities' use of the ELG method to a desire by utility finance managers to increase cash flow and a desire by utility investors to reduce risk through accelerated capital recovery. He emphasized that the rules and standards governing capital recovery through depreciation require that public utilities recover their capital investments in a systematic and rational manner, accomplished by estimating service life through actuarial analysis and other objective techniques.

He noted that in the pending Indiana Michigan Power Company rate case, the utility proposed depreciation rates using the ALG procedure; no party opposed the utility's use of the ALG procedure and no party proposed using the ELG procedure. He stated that, in his experience, the ALG procedure is the most commonly used procedure by analysts in depreciation proceedings. Thus, he concluded, the majority of depreciation rates approved by regulators around the country are calculated under the ALG procedure.

Mr. Garrett stated that if the IURC approves the ELG procedure in this case, ratepayers will not only pay excessive rates next year, but will continue to pay excessive rates each year until the next depreciation study. He claimed that under these circumstances, it may actually be inaccurate to refer to what Duke Energy Indiana is doing as the "ELG procedure"; he stated for that description to be accurate, depreciation rates must be adjusted each year. Rather, he claimed, it would be more accurate to describe Duke Energy Indiana's "scheme" as the "Accelerated Cash Flow" procedure. He testified that if the IURC accepted all of Duke Energy Indiana's substantive depreciation positions, but simply adopted the ALG procedure, it would result in depreciation rates that are much more fair and reasonable than those proposed by the Company. He further testified that it could be reasonable to use the ELG procedure if Duke Energy Indiana was also proposing to have its depreciation rates adjusted every year in order to reflect a mathematically proper application of the ELG procedure, but that was not a part of the Company's filing. Instead, he claimed, to the extent the Company's ELG-derived rates are adopted, the Company will receive arbitrarily higher cash flows for its investors each subsequent year after this proceeding until its next depreciation study is filed. Under these circumstances, he concluded, the Company has not made a convincing showing that its proposed rates are not excessive.

Mr. Garrett offered an alternative ELG proposal, stating that if the IURC is inclined to adopt the ELG procedure as proposed by the Company, he has also presented his depreciation parameter adjustments under the ELG method. He emphasized these adjustments do not represent the OUCC's primary recommendation, which are the ALG depreciation rates outlined in his testimony.

Mr. Garrett next addressed the issue of contingency costs. He testified that the Company's terminal net salvage costs are estimated through demolition studies for most of its generating units. He stated that the demolition studies include contingency costs that purportedly reflect uncertainties in future demolition estimates. However, he claimed that contingency costs are unknown by definition, and therefore are not known and measurable. He stated that charging current ratepayers for speculative costs that may not even occur up to decades in the future is inherently problematic from a ratemaking perspective. Mr. Garrett stated that Duke identified no legal obligation in its testimony that requires it to demolish its power plants consistent with the activities described in the decommissioning cost estimates. He opined that in the absence of such a legal requirement being imposed in the foreseeable future, actually incurring these costs is speculative. He also suggested that if and when Duke actually demolishes the power plants and requires more funding to do so, it can request additional funds from ratepayers when actual costs are known.

With regard to the issue of inventory costs, Mr. Garrett noted that Duke Energy Indiana included $185 million of inventory costs as part of its decommissioning cost estimates. However, he stated, inventory costs are not typically included as part of decommissioning cost estimates, and he testified that he could not recall ever seeing such costs proposed in a decommissioning study, including those filed by Burns & McDonnell in prior cases. He noted that decommissioning studies estimate the terminal salvage and cost of removal of generating facilities, and he testified that Duke Energy Indiana has not shown how the inclusion of inventory relates to that process. Furthermore, he stated that Burns & McDonnell has not conducted an analysis supporting the level of inventory included in the decommissioning costs.

Mr. Garrett next addressed the Company's use of escalation factors to escalate its demolition cost estimates from present-day dollars to the future retirement date of each generating unit by applying an annual cost inflation factor. According to Mr. Garrett, the problem with this approach is that current ratepayers are forced to pay for a future-value cost with present-day dollars. He claims that this "scheme" violates basic time-value-of-money principles. He testified that if future, escalated costs are allowed, they should then be discounted back to present-day dollars by the Company's weighted average cost of capital, noting that a similar approach is used to account for asset retirement obligations. He concluded, however, that it would be more straight-forward and reasonable to simply disallow the escalation factors and base the Company's decommissioning costs on present value.

(III) **Industrial Group's Evidence.** Brian Andrews, with Brubaker & Associates, testified on behalf of the Industrial Group with respect to depreciation issues. His stated that Duke Energy Indiana's proposed depreciation expense increase is excessive and unduly burdens customers.

He testified that Duke Energy Indiana's continued reliance on the ELG procedure for calculating depreciation rates is burdensome to customers. He claimed that ELG depreciation rates are front-loaded and must be updated annually for proper implementation. He further claimed that Duke Energy Indiana is the only Duke electric company that utilizes the ELG procedure to calculate depreciation rates, and it has the highest depreciation rate of any of the Duke electric companies. He stated that all other Duke electric companies use the ALG procedure, the most commonly utilized procedure for calculating depreciation rates.

He argued that, by rejecting ELG in favor of ALG, the IURC has an excellent opportunity to achieve the following: (1) allow Duke to retire its coal plants early according to its preferred portfolio, helping achieve significant carbon reductions in Indiana, (2) significantly reduce the rate increase while allowing those early retirements and the resources that will eventually replace them, and (3) utilize the depreciation procedure that is most commonly used in the country.

Mr. Andrews also argued that Duke Energy Indiana is attempting to recover through depreciation rates an excessive amount of costs for the demolition of its production plants. He noted that in the decommissioning cost estimates, Duke has included net inventory costs, which is the level of inventory that existed at the plants as of June 2018. He took the position that, as Duke knows the precise retirement dates of these facilities, Duke should effectively manage this inventory and strive to eliminate these balances over the remaining life of the plants. He argued that these costs should be removed from the decommissioning costs estimates that are included in the net salvage rate and depreciation rate calculations.

He also noted that, in the decommissioning cost estimates, Duke has included contingency costs. He characterized these costs as simply a 20% adder to the demolition costs and unnecessary depreciation expense. He recommended that these contingency costs be removed from the decommissioning costs estimates that are included in the net salvage rate and depreciation rate calculations.

Mr. Andrews observed that in the net salvage rate calculations, Duke has included cost escalation. He testified that these costs were determined with an excessive and unsupported 2.5% annual inflation rate and burden current customers with unnecessary depreciation expense. He recommended that these escalation costs should be based on 2.0% inflation before being included in the net salvage rate and depreciation rate calculations.

Mr. Andrews stated that the IURC should reject Duke's ELG depreciation rates and approve the depreciation rates presented in his testimony. He testified that this will reduce the test year depreciation expense by $120 million, or by 83% of Duke's proposed increase, while still allowing coal plant retirements at Duke's proposed time schedule.

(IV) <u>Petitioner's Rebuttal Evidence</u>. Mr. Spanos testified in rebuttal, noting that while each party proposes a fairly significant change in depreciation expense compared to the Company's proposal, the vast majority of the dollar impact of their changes is due to their deviation from Commission precedent. That is, most of their proposed reduction in depreciation expense is based on issues that the Commission has already decided. He stated that the issue with the single largest impact is the Company's use of the Equal Life Group ("ELG") procedure instead of the Average Life Group ("ALG") procedure. He noted that the Commission has clearly stated that "[w]e consider the debate between ELG and ALG to have already been resolved. This Commission has frequently and consistently expressed its preference for the use of the ELG procedure."[25] The Commission has similarly ruled that it is appropriate to include contingency in decommissioning estimates and that decommissioning estimates should be escalated to the date of retirement (for example, see NIPSCO Cause No. 43526). Accordingly, the only issues raised by OUCC and IG that have not been resolved by the Commission relate to the inclusion of inventory costs in decommissioning (which is addressed by Duke Energy Indiana rebuttal witnesses Kopp and Mosley), Mr. Andrews' use of a lower escalation rate, and Mr. Garrett's life estimates for a few accounts.

Mr. Spanos stated that the OUCC proposes a reduction in depreciation expense of $107 million, however, $93 million of this amount is due to the use of the ALG procedure, the removal of contingency and the removal of escalation. Similarly, he stated, the Industrial Group proposes a $120 million reduction in depreciation expense, however, $88.7 million of this is due to the use of the ALG procedure. An additional amount is the result of the parties' proposal to remove

[25] IURC 8/25/2010 Final Order in Cause No. 43526 at 51.

contingency. Accordingly, he emphasized, the vast majority of both of their proposals are the result of issues that have long been resolved by the Commission.

Mr. Spanos testified that the OUCC and Industrial Group had presented no compelling reasons to overturn Commission precedent on these issues. The largest dollar impact of these issues relates to the Equal Life Group ("ELG") procedure. He noted that Mr. Andrews provides few arguments to support his proposal, other than claiming that the ELG procedure is "front loaded and that it requires annual updates" and to observe that one isolated utility in Indiana has used the ALG procedure. While Mr. Garrett and Mr. Andrews claim that the ALG procedure is the "most commonly utilized procedure," Mr. Spanos testified that this neither demonstrates that ELG is an inappropriate procedure nor does it change that this Commission has consistently favored the ELG procedure.

With regard to Mr. Garrett's and Mr. Andrews' argument that ELG depreciation requires annual updates, Mr. Spanos testified that this argument is consistent with Commission precedent and the simple examples they provide to support their opinions are not reflective of real-world operations. He stated that this argument is unpersuasive for multiple reasons. First, he noted this Commission has used ELG for many years and has not required companies to update depreciation rates annually. Second, he stated that both Mr. Garrett and Mr. Andrews are incorrect that annual updates would be required. He pointed to the fact that both examples shown to support their opinions are simplistic examples based on only a single vintage of plant. Thus, their examples do not match real-world experience. For most utility plant accounts, he stated, assets are added and retired every year. Due to this continual activity, he testified, ELG depreciation rates do not actually change as much as Mr. Garrett and Mr. Andrews claim. Third, he testified that annual updates are quite common in Pennsylvania. He stated that his firm performs depreciation studies – and annual updates – for most utilities in Pennsylvania. As a result, he has the opportunity to review changes to depreciation rates that occur each year that result from annual updates to depreciation calculations. In actual practice, he testified, ELG depreciation rates are much more stable than Mr. Garrett and Mr. Andrews claim. In fact, he stated, in aggregate, the ELG depreciation rates typically do not change dramatically from year to year and would not warrant annual updating as Mr. Garrett and Mr. Andrews assume.[26] Mr. Spanos testified that, in reality, there is little need to update depreciation rates annually when using the ELG procedure. He noted that the Commission has not been concerned enough with this issue to require annual updates in the many decades since the ELG procedure was first adopted. Accordingly, he concluded, Mr. Garrett's and Mr. Andrews' arguments to this effect are not a persuasive reason to abandon its use in Indiana.

---

[26] Mr. Spanos noted there are other aspects of depreciation that have the potential to change each year. For example, any additions to life span property result in a change to the depreciation rate (since the new asset will have a shorter life than the existing assets at the life span facility). Remaining life depreciation rates also change each year. He pointed out that Mr. Garrett proposes a change in approach from Commission precedent for terminal net salvage that would require annual updates, proposing to only include decommissioning costs at today's cost levels, which would mean the decommissioning costs would need to change each year due to changes in cost levels that occur from year to year. However, Mr. Spanos stated, for Mr. Garrett's terminal net salvage proposal (as well as other aspects of depreciation that change each year), he appears unconcerned with the potential for annual updates to depreciation rates. This gives less merit to Mr. Garrett's concerns regarding ELG, in Mr. Spanos' view.

Mr. Spanos also testified about the downsides of moving to an ALG methodology. He testified that a switch from ELG to ALG depreciation rates will result in artificially low depreciation rates due to the higher accumulated depreciation currently on the Company's books due to the historical use of ELG depreciation rates. He stated that this in turn will result in a short-term benefit that will be paid for by future customers who will also pay a return on the higher rate base that will result from the proposed ALG depreciation rates. He characterized this approach as inequitable both because it will artificially reduce rates at the expense of future customers and because those customers will have to pay for the costs of generation that replaces the Company's coal-fired generation that will be retired. He concluded that Mr. Andrews' proposal would unfairly shift the costs of power plants that will soon be retired to future customers, who will receive no service from these plants. Additionally, Mr. Spanos noted, the historical use of ELG depreciation rates, as well as the inclusion of contingency and escalation in decommissioning estimates, already provides a benefit to customers as the Company transitions from coal-fired generation. While the retirement of coal-fired generation at earlier ages than previously expected does result in an increase in depreciation expense in this case, the fact that the Company has recovered more depreciation to date due to the historic use of ELG depreciation rates and more adequate levels of decommissioning (due to the inclusion of contingency and escalation) means that accumulated depreciation is higher than had Mr. Andrews' and Mr. Garrett's preferred approaches been adopted. The result, he noted, is that there is less to recover for the plants that will be retired. To put this a different way, he explained, had ALG been used in the past and no contingency or escalation included, the increase in depreciation resulting from earlier coal-fired generation would be higher than it is in the current case. He testified that the Commission in the past has wisely resisted short-term reductions in depreciation at the expense of the future and should continue to resist the temptation for short-term rate reductions at the expense of future generations of customers.

Mr. Spanos emphasized that Mr. Garrett overstates the potential of fully depreciating an asset while it is still in service and minimizes the impact of the (more likely) possibility of an asset being retired from service before becoming fully depreciated. Mr. Garrett's argument is that fully depreciating an asset while it is still in service may incentivize a utility "to retire and replace the asset to increase rate base, even though the retired asset may not have reached the end of its economic useful life." However, in Mr. Spanos' experience, this scenario does not commonly occur. Because depreciation studies are updated periodically, if an asset will last longer than originally expected, depreciation rates are revised to reflect this longer service life. Depreciation rates are accordingly updated so that the asset will continue to be depreciated until its actual retirement. Additionally, for facilities such as power plants, capital additions are typically required in order to extend the life of the facility, which increases the costs that need to be recovered over the facilities' service lives. As a result of these factors, it would be unusual for a large generating unit to become fully depreciated before it is retired.

However, Mr. Spanos testified, there are much more pronounced risks of underestimating depreciation – both to the Company and to customers. First, he stated, the converse of Mr. Garrett's economic argument is true. Depreciation rates that are too low can also incentivize economic inefficiency. Assets such as power plants might remain in service even if they are no longer economic to operate because they have not been adequately depreciated. This can be harmful to customers (and potentially to other stakeholders and the environment) if it results in inefficient and costly older facilities remaining in service longer than they are economic to operate. Second, the probabilities of an asset being under-depreciated versus being over-depreciated when retired are not symmetric. In Mr. Spanos' experience, it is more common that assets such as power plants are retired before being fully depreciated than assets are fully depreciated before being removed from service. One needs to look no further than the current case to see instances of power plants retiring prior to being fully depreciated. Finally, Mr. Spanos addressed Mr. Garrett's statement on page 10 of his testimony, that "[i]f, on the other hand, an asset must be retired and taken out of service before it is fully depreciated, there are regulatory mechanisms that can ensure the utility fully recovers its prudent investment in the retired asset" ignores two important concepts. Mr. Spanos noted the risk that parties will propose to disallow such a regulatory mechanism, such as the Industrial Group has done in this proceeding regarding the Company's retired Wabash River Unit 6. The second is that the recovery of costs after an asset such as a power plant is retired by definition results in intergenerational inequity.

Mr. Spanos testified that Mr. Garrett is incorrect to argue that "it is preferable for regulators to ensure that assets are not depreciated before the end of their economic useful lives." While the goal is to estimate depreciation as accurately as possible, it is important to remember that depreciation is a forecast of events many years in the future and as a result estimates do not always match the actual experienced lives and net salvage of a Company's assets. Given this reality, Mr. Spanos opined, erring on the higher side for depreciation rates is preferable than the lower side because the likelihood and the risks of adverse effects on both the utility and customers are greater if depreciation is underestimated. He also added that too low of depreciation rates increases rate base, which results in customers paying higher total rates due to the return on rate base.

Mr. Spanos also took issue with Mr. Garrett's and Mr. Andrews' use of the word "accelerated" to describe the ELG methodology. He testified that ELG is a straight line method; ELG recovers costs on a straight line basis over the expected life of each equal life group.

Mr. Spanos reiterated that there are sound reasons to use the ELG procedure. He noted that this Commission has addressed this issue multiple times in the past and ruled in favor of ELG. And he noted that ELG is also discussed and supported in authoritative depreciation texts and academic literature. One such authority – and a very significant one – is Robley Winfrey, who, as a professor at Iowa State University, developed the Iowa survivor curves that are universally used in estimating service lives based on historical retirement data and is generally regarded as the father of utility depreciation practices, referred to the ELG procedure as "the only mathematically correct procedure."[27]

Mr. Spanos also addressed the fact that Mr. Andrews' proposal would result in unfairly pushing current customer costs onto future customers. He stated that it is important to understand that depreciation rates not only impact current period depreciation expense but also impact the level of accumulated depreciation. Higher depreciation rates result in higher accumulated depreciation and lower depreciation rates result in lower accumulated depreciation. Accumulated depreciation affects customer rates in two ways. The first is that, because the Company uses remaining life depreciation rates, accumulated depreciation impacts the calculation of depreciation

[27] Robley Winfrey, Depreciation of Group Properties, Bulletin 155 (Ames, IA: Iowa State University Press, 1942, reprinted 1969); p. 71.

rates and, in turn, current period depreciation expense. Because depreciation recovers the full cost (original cost less net salvage) of assets over their service lives, higher depreciation now means lower depreciation in the future (and vice versa). Similarly, higher depreciation in the past means lower depreciation now. He explained that the second way accumulated depreciation affects customer rates is that accumulated depreciation reduces rate base. Thus, higher depreciation rates result in a lower return on rate base in the long run because rate base will be lower. This impact exceeds the impact of higher depreciation rates in many circumstances. For example, the use of ELG rates in the long run typically results in lower customer rates due to lower rate base, since ELG rates are usually higher than ALG rates.

Additionally, he emphasized that it is also important to understand that the change in depreciation resulting from the OUCC and Industrial Group's proposed change to ALG rates is not simply due to the difference between the two procedures. Rather, a portion of this change results from the fact that accumulated depreciation is higher today due to the historical use of ELG depreciation rates than it would have been had ALG depreciation rates been used. A change to ALG rates today will, therefore, result in a greater benefit to today's customers than to other generations of customers. This occurs both because depreciation rates are lower due to the historical use of ELG depreciation rates and because rate base is lower due to the higher accumulated depreciation resulting from the historical use of ELG depreciation rates. If Mr. Andrews' proposal were adopted, it will be future customers that pay the cost for this benefit given to current customers. Future customers will have to pay higher ALG depreciation rates than current customers as remaining life depreciation rates result in accumulated depreciation that will eventually revert to a lower level from the use of the ALG procedure. Future customers will also have to pay a return on the higher rate base that results from the lower ALG depreciation rates. In summary, he testified, Mr. Andrews' proposal will result in shifting costs from today's customers to future generations of customers. It is not reasonable, Mr. Spanos concluded, to ask future customers to bear these costs as Mr. Andrews proposes.

Mr. Spanos also noted that the use of ALG depreciation rates will also risk larger increases in depreciation in the future. He testified that if Mr. Andrews' proposal to use ALG depreciation rates were adopted, then accumulated depreciation would be lower in the future. If, in the future, power plants (or any other asset) were retired earlier than expected, then the result of Mr. Andrews' proposal would be that more costs would have to be recovered in a short period of time. As a result, his proposal risks more significant increases in depreciation in the future. Additionally, he noted, the historical use of ELG depreciation rates, as well as the inclusion of escalation and contingency for decommissioning costs, means that the increase in depreciation today that results from the earlier retirement of coal-fired power plants is less pronounced than it otherwise would have been. In other words, he stated, customers today are benefitting from the historical use of ELG, escalation and contingency; had Mr. Andrews and Mr. Garrett's preferred approaches been used historically, there would have been more costs to recover today and the increase in depreciation expense would have been higher than it is in the current case.

Mr. Spanos next addressed the three adjustments proposed by the OUCC and Industrial Group to the decommissioning cost estimates used in the depreciation study. The first type of adjustment is related to the escalation of decommissioning costs to the time of retirement. The OUCC proposes to remove the escalation component entirely. The Industrial Group recommends the escalation of decommissioning costs, but uses a 2.0% escalation rate instead of the 2.5%

escalation rate proposed by Mr. Spanos. The second proposed adjustment is that both the OUCC and Industrial Group advocate removing contingency from the decommissioning estimates. Mr. Spanos noted that both of these issues have been previously addressed by the Commission, which has ruled in favor of the Company's proposals to include escalation and contingency. The third proposed adjustment is that both parties propose the removal of inventory costs from the Company's terminal net salvage estimates. Mr. Spanos noted that he does not address this issue, which is instead addressed by rebuttal witnesses Mr. Kopp and Mr. Mosley. He also noted that Mr. Kopp also addresses the contingency issue, although Mr. Spanos briefly discussed Commission precedent regarding this issue.

With regard to the issue of including escalation in the calculation of decommissioning costs, Mr. Spanos stated that escalation is necessary in order to recover the full net salvage costs of these facilities over their service lives and has previously been accepted by the Commission. He noted that Mr. Andrews recognizes that escalation should be included in the terminal net salvage estimates, but proposes a lower escalation rate of 2.0%. Mr. Spanos testified that, in order to equitably recover the full costs of the Company's assets, including net salvage, net salvage must be based on future costs because decommissioning is going to occur in the future. He emphasized that net salvage must include the effects of future increases in costs, as recognized on multiple occasions by this Commission. Most recently, he noted, the Commission stated "[w]e have repeatedly rejected attempts to eliminate or curtail the effects of future inflation when calculating net salvage."[28] Accordingly, he stated, the decommissioning costs used in the depreciation calculations for terminal net salvage must be estimates of the future cost at the time of decommissioning. For this reason, he explained, if decommissioning estimates are developed using the cost to decommission a plant today, then these costs should be escalated to the time period in which they are expected to be incurred.

Mr. Spanos noted that Mr. Garrett makes one main argument in support of his proposal to eliminate escalation from the terminal net salvage estimates. He states that "[i]t is not proper to charge current ratepayers for a future cost that has not been discounted to present value." He supports this assertion by stating that "[t]he 'time value of money' concept is a cornerstone of finance and valuation." Mr. Spanos testified that Mr. Garrett's opinion is contradicted by the fact that Commission precedent supports the escalation of decommissioning costs. Further, Mr. Spanos testified, his opinion on this concept with regard to depreciation is incorrect. Mr. Spanos reiterated that depreciation is based on the actual cost at the time of installation or retirement. While the "time value of money" may be a cornerstone of finance and valuation, it is not a concept used in depreciation as widely practiced in the industry. Indeed, Mr. Spanos testified, failing to incorporate escalation, as Mr. Garrett proposes, will result in understating future net salvage costs, resulting in intergenerational inequity by forcing future customers to pay too much for the facilities.

Mr. Spanos next noted that, unlike Mr. Garrett, Mr. Andrews includes an escalation component in his terminal net salvage estimates. However, he uses a 2.0% escalation rate instead of the 2.5% escalation rate used by the Company which he says "has no support and is excessive."

---

[28] *In re Indiana-American Water Co*., Cause No. 44992 at 10 (IURC May 30, 2018).

Mr. Spanos testified that his estimate of 2.5% is reasonable for a long term rate of cost increases for power plant decommissioning. He stated that his estimate is consistent with escalation rates used previously, as well as other sources including long-term averages of Consumer Price Index ("CPI") inflation and long-term inflation forecasts; the latter is compiled by the Federal Reserve in the Livingston Survey. He noted that CPI inflation has typically been lower than long-term construction cost increases and so, if anything, his estimate is conservative.

Mr. Spanos testified that Mr. Andrews only provided an analysis based on comparing the Livingston Survey to actual CPI inflation since 1991. From this analysis, he concludes that the "average forecast error is 0.6 percentage points" for this survey since 1991. Since the current 10-year median forecast is 2.26%, he subtracts 0.6 from 2.26% to get a value a 1.66%. He concludes that 1.66% is a more realistic forecast, although he proposes an escalation rate of 2.0% "to be conservative." Mr. Spanos testified that there are multiple issues with Mr. Andrews' analysis. First, he stated that the Livingston Survey is not the only support for Mr. Spanos' estimate. Second, Mr. Andrews' calculation of the forecast error is entirely the result of two periods of time. The first is from the early 1990s and the second from the late 2000s. The forecast error in the early 1990s resulted because these years followed the high inflation of the 1970s and 1980s. That is, forecasters not unreasonably expected that higher inflation to continue, but it did not. The second period is comprised of years that encompassed the Great Recession. The Great Recession resulted in very low inflation and even deflation, but was an abnormal event. Accordingly, Mr. Spanos testified, the period of time reviewed by Mr. Andrews' likely overstates any forecast error, particularly downside errors. Indeed, the last two decades have experienced low inflation by historical standards. It should be at least as likely that current forecasts would be too low rather than too high. However, he testified, Mr. Andrews only anticipates that forecasters could be estimating too high of inflation.

Mr. Spanos testified that these concepts are illustrated if we look at longer term inflation. He stated that looking at longer term inflation rates shows that there have been many years with higher inflation. As a result, he explained, simply assuming that a 2.0% inflation rate will continue into the future is not necessarily a reasonable assumption. Mr. Spanos provided data going back to 1960 and noted that the inflation that occurred over 10-year periods was greater than 2.5% in many years. Additionally, Mr. Spanos testified that while the CPI provides a good indication of changes in prices in the overall economy, it is not necessarily a good indicator of changes in decommissioning costs. A price index that serves as a better proxy for changes in decommissioning costs is the Handy Whitman construction cost index. Mr. Spanos provided a comparison of the changes in the Handy Whitman Index for Steam Production Plant to CPI over the past 20 years; the data shows that construction costs have increased faster than CPI over this time period. Further, he stated, the data indicates that for every single long-term period ending in 1960 through 2018, the Handy Whitman index increased at an average rate that was greater than the 2.5% escalation rate he proposed. Thus, he concluded, the Handy Whitman index supports a higher escalation rate than he proposed. In summary, he testified that multiple sources support the 2.5% escalation rate he used, and, if anything, his estimate is conservative. He concluded that Mr. Andrews' estimate is, in his judgment, too low and will not fully recover the costs to retire the Company's power plants over their service lives.

Mr. Spanos next discussed the issue of contingency. He stated that Mr. Garrett and Mr. Andrews also both propose the removal of the contingency component from the decommissioning cost estimates. Their arguments for the removal of contingency also do not stand up to scrutiny, in Mr. Spanos' view. Mr. Spanos noted that the use of contingency has also been previously addressed by the Commission. For example, he noted the following excerpt from a NIPSCO case, in which the Commission held that the inclusion of contingency was appropriate and also noted that Commission precedent supported the inclusion of contingency:

> Mr. Selecky argued either the post-remediation value of the land in industrial condition should be an offset to the dismantlement costs or the contingency should be eliminated as a trade-off for the value of the land. Mr. Selecky did not identify the dollar value of the land after dismantlement. As a result, there is no evidence in the record to guide us in determining whether this would produce a material difference in the depreciation rates or be a reasonable trade-off for the contingency, assuming for the sake of argument it would even be proper to treat a non-depreciable asset like land as salvage. Further, we find it noteworthy that Mr. Selecky is not a licensed real estate appraiser. As a result, the record is devoid of any evidence to judge whether his proposal to equate the value of the land with the contingency is reasonable. (42356 Order at 53-54.) We also give weight to the fact that the 20% contingency factor used in the BMcD demolition cost studies is conservative compared to the 25% contingency factor we accepted in PSI Energy, Inc., Cause No. 42359, at 70-71. Also, the assumption that the sites will be remediated to industrial condition, rather than greenfield condition, is also conservative. Id. at 70. No evidence was presented that this Commission has ever used the value of land as an offset to an asset's cost of removal. In fact, Mr. Selecky did not identify to us any decision of any regulatory commission accepting his position regarding land and the contingency. Petitioner's JJS-R5; Petitioner's Ex. JJS-R6. Given that Mr. Selecky's recommendation would be such a departure from our past practice and that we have scant evidence to guide us in this exercise, we reject Mr. Selecky's proposal.

Mr. Kopp also provided rebuttal testimony regarding the appropriateness of including contingency in the decommissioning study for this proceeding. Specifically, he noted that the application of contingency is a common and prudent practice in the construction industry, and it is included in order to recognize the probability of increases in cost over the base estimated costs due to unknowns. Mr. Kopp explained that some of these costs cannot be determined until the dismantlement process has begun. Therefore, contingency is applied on top of the base estimated cost in order to formulate a reasonable estimate to dismantle the generating facilities.

Mr. Kopp explained that the 20% contingency amount he included in this decommissioning study is the same percentage as the contingencies he has prepared for decommissioning studies for other electric utilities that have been approved by regulatory agencies in other states.

Mr. Kopp next explained that contingency is important and appropriate to include because, for decommissioning projects, there is some uncertainty associated with work conditions, the scope of work, and how the work will be performed. There also is some uncertainty associated with estimating the quantities for dismantlement of facilities. These uncertainties result from the age and limits on drawings available, as well as the absence of testing results for environmental contamination prior to preparation of these types of studies. Contingency costs account for these unspecified but expected costs and are in addition to the direct costs associated with the base decommissioning costs for known scope items.

Contingency is added to account for unknown, but reasonably expected to be incurred costs. These costs are related to weather delays, unknown environmental contamination, discovering equipment or materials not shown on drawings, additional dewatering requirements and changes in the manner the work is performed.

Mr. Kopp responded to Mr. Andrews' contention that Duke Energy Indiana has no legal obligation to demolish its retired power plants by expanding on the explanation in his direct testimony of the necessity for demolition of power plants. He explained that although there may be no legal obligation to demolish a power plant, there are legal obligations to comply with environmental regulations. He also explained that the alternative to full demolition is to retire a plant in place. He explained that retiring a plant in place requires carrying costs that are necessary to maintain a safe site and be in compliance with applicable regulations. Mr. Kopp stated in his experience he has found that retiring in place is not a cost-effective long-term scenario when the carrying costs are taken into account.

Mr. Kopp concluded by stating that excluding these reasonably expected to be incurred costs by not including contingency costs will not give the full picture of decommissioning costs. If these costs are not accounted for in planning for future decommissioning, the costs will be passed on from the current ratepayers to future ratepayers.

Company witness, Mr. Mosley, provided rebuttal testimony addressing the inclusion of inventory in the decommissioning study. He explained Duke Energy has experience managing generating stations as they near the end of their useful lives and consistently attempts to deplete remaining inventory and/or transfer it to another generating facility where it can still be used. However, there are risks associated with premature depletion of inventory due to limited availability and long lead time of parts required to sustain reliable operation that must be considered.

In addition, Mr. Mosley stated that there are often limitations on the compatibility of inventoried parts that could be transferred from one station to another. For example, most spare parts that fit Gallagher's coal mills do not fit the mills at Gibson or Cayuga. Most steam turbine and generator parts are model specific and cannot be used at other facilities. Combustion turbine and generator parts have some capability with like-in-kind models, but circa-2000 machine parts would rarely be compatible with future gas-fired generators.

Mr. Mosley also explained that as the existing coal and gas-fired generators are retired, there are increasingly less remaining opportunities to transfer useful inventory. Therefore, reflecting leftover inventory in the cost of decommissioning is a reasonable means of addressing a future where increasing numbers of generating units are retired and replaced.

Mr. Kopp also provided rebuttal testimony regarding the inclusion of obsolete inventory remaining at the end of a generating station's useful life in this decommissioning study. He explained that disposing of remaining inventory is just as much a part of decommissioning a station as disposing of other equipment and plant components. It must be safely sold, moved to other locations, or scrapped. In fact, the warehouse or other portions of the plant where the supplies are held cannot be demolished until the inventory is safely removed.

Mr. Kopp then rebutted Mr. Andrews' contention that if this equipment is not placed in service, that it is not used and useful by explaining that Andrews' argument ignores the fact that inventory is required to be maintained in order to achieve appropriate reliability of the plants and to facilitate routine maintenance on the facilities. It is necessary to purchase this inventory before it is needed, in order to reduce outage time, and even if it is not installed, it has still served a useful purpose in maintaining plant reliability.

Mr. Kopp's testimony also stated that the value of this inventory that cannot be reclaimed through sale or scrap of the inventory is directly related to the retirement of the facility. If the facility were to remain in service, this inventory would retain its value to the plant. However, when the plant is retired, the value of this inventory is reduced to the value it has as salvage or scrap. This reduction in value of the inventory is a cost associated with net salvage rates associated with retirement and demolition of the facility. In response to Mr. Garrett's contention that Mr. Kopp had never proposed including inventory in decommissioning studies before, Mr. Kopp also cited to approval of the inclusion of inventory in a decommissioning study prepared for FPL by the Florida Public Service Commission.

Company witness Ms. Douglas also responded to the recommendations of Mr. Garrett and Mr. Andrews regarding the inclusion of end-of-life generating plant M&S inventory costs as a cost of decommissioning and dismantlement. She explained that unlike other plant, property and equipment used at a generating station, which is depreciated over its useful life and the cost of which is recovered from customers served by and benefitting from the electricity generated at the station during its useful life, under the current ratemaking construct, recovery of the cost of M&S maintained in inventory occurs only once the parts and equipment in inventory are installed in the plant. She explained that when base rates are set, under traditional Indiana ratemaking practice, inventory is included in rate base for return purposes, but is not depreciated over its life like plant. Further, the current construct assumes the M&S inventory can be used up before retirement occurs and whatever amount is left can be reused elsewhere or sold, with no current ratemaking means for recovering the cost of the remaining end-of-life inventory from the customers for whose benefit the inventory held for reliability purposes at the station was maintained. As also discussed in the Rebuttal Testimony of Company witness Ms. Melissa B. Abernathy, without assurance of regulatory recovery of any remaining inventory costs that have now become obsolete due to the retirement, the Company must write the inventory off as an additional, one-time expense. Ms. Douglas further explained that the Company's proposal is reasonable because it enables the forecasted costs of the end-of-life M&S inventory to be recovered in a rational and systematic way over the remaining life of the plant from the customers who are being served by the plant and benefitting from the reliability that the inventory brings to the plant. Ms. Douglas opined that this approach is a fair and balanced way to address this issue to prevent large negative financial impacts at a plant's end of life for companies who have purchased and managed their M&S reasonably for the benefit of customers. Ms. Douglas noted that the Rebuttal Testimony of Company witness Mr. John Sullivan addresses the negative impacts on credit quality and financing costs that may result from write-offs such as this. Although Ms. Douglas concluded by noting that an alternative to recovery over the life of the plant via decommissioning costs would be the pre-approval by the Commission of the use of a regulatory asset at the end of the plant's life, with the remaining value to be recovered from customers over time in a future rate case, she stated that the Company believes inclusion of a value in depreciation rates is a reasonable and logical option to avoid intergenerational inequity.

Mr. Kopp concluded his rebuttal by reiterating that the costs included in the decommissioning study are reasonably reflective of the actual costs necessary for to decommission and demolish the plants and are an appropriate basis for setting electric rates in this matter and for use for planning for decommissioning costs going forward. The costs were prepared with the intent of accurately representing what contractors would bid to decommission and demolish the equipment, address environmental issues, and restore the site through a competitive bidding process, based on performing known decommissioning tasks under ideal conditions.

(V) **<u>Commission Discussion and Findings</u>.** The depreciation-related issues in this case relate to: (1) the ELG versus ALG methodology; (2) the appropriate calculation of terminal net salvage estimates; and (3) estimated useful lives for certain mass property accounts and coal generating units, including IRP issues. We address each of these issues in turn.

First, with respect to the question of whether the ELG or ALG method should be used, we have repeatedly determined that the ELG methodology is reasonable, superior, and preferred. Moreover, our approval of the use of the ELG methodology is longstanding. It appears that the initial approval of ELG by the IURC (then the Public Service Commission of Indiana) was in 1981 in Cause No. 36361, involving Citizens Gas & Coke Utility (the ELG method was then referred to as the unit summation procedure). The following year in a case involving Indiana Gas Company, Inc., Cause No. 36816, the use of the ELG procedure (again referred to as the unit summation procedure) was supported by both the Company and the Commission Staff. In the Commission Staff report (at page 2), the Commission Staff stated with respect to the evidence filed by the Company: "Exhibit No. 7 has been reviewed and accepted without objection. The procedure used is called the 'Unit Summation' method and was first presented in a Citizens Gas General rate case Cause No. 36361. At this time it was thoroughly investigated and determined that the procedure was acceptable to Commission Engineering." In its October 27, 1982 Order in that *Indiana Gas* case, the Commission concluded: "Accordingly, we . . . find that the annual depreciation rates proposed by Petitioner as set forth by plant account in Petitioner's Exhibit No. 7 should be approved" (36816 Order, at pages 24-25). The Commission reaffirmed the unit summation procedure for Indiana Gas in a subsequent order in Cause No. 38080 dated September 18, 1987. The ELG procedure was also approved for Indiana Bell Telephone Company, Inc. ("Indiana Bell") in Cause Nos. 38376 (IURC Feb. 17, 1988) and 39525 (IURC Aug. 11, 1993). In its Order in Cause No. 39525 (at page 6), the Commission, referring to its previous order for Indiana Bell, "found that ELG procedures were superior to [vintage group] procedures where those ELG procedures were available for use. We found there that such procedures matched capital recovery with consumption of plant better than the [vintage group] procedure because the ELG methodology fully accounts for the expected life of each item in the vintage to develop an accurate depreciation rate, while the [vintage group] method produces a less accurate averaged rate." Also, in the Commission's Order dated April 4, 1990 in Cause Nos. 37414-S2 and 38809 related to Public Service Company of Indiana, Inc., ("PSI," now Duke Energy Indiana), the IURC concluded (at pages 65-67): "[a]ccordingly, we find that whether the speed of capital recovery under the ELG procedure is quicker or slower than under the ALG procedure is really a function of the life of the asset, as it should. * * * Therefore, we find that PSI's proposed use of depreciation rates based on the ELG procedure is reasonable, appropriate and is hereby approved."

More recently the ELG procedure was approved in the Commission's November 21, 2006 Order in Cause No. 43081, related to Indiana-American Water Company, Inc., ("Indiana-American") which was an updated depreciation study set forth in Cause No. 42520. Also, in 2004, PSI Energy (now Duke Energy Indiana) had depreciation rates approved using the ELG procedure as part of its base rate case (Cause No. 42359). The Commission's May 18, 2004 Order in Cause No. 42359 reads as follows with respect to ELG developed rates:

> With respect to the use of the ELG or ALG methodologies to determine average service lives, we note that Mr. Selecky advocates the use of ALG to determine average service lives as opposed to Mr. Spanos' ELG methodology. This Commission on numerous occasions has accepted the use of the ELG methodology. *See, Indiana-American Water Co.*, Cause No. 40703, 1997 Ind. PUC LEXIS 429 (Ind. Util. Reg. Comm'n, December 11, 1997). Therefore, based on our review of the testimony we find that Mr. Spanos' use of the ELG methodology is acceptable. (2004 PSI Order at 72).

As we stated in our Order in Cause No. 43526, "We consider the debate between ELG and ALG to have already been resolved. The Commission has frequently and consistently expressed its preference for the use of the ELG procedure." *In re Petition of Northern Indiana Public Service Co.*, Cause No. 43526, at p. 51(IURC; 08/25/10).

We see no reason to change the Commission's longstanding practice regarding the use of the ELG methodology in the instant case. The facts are clear: the ELG procedure produces more precise and more accurate depreciation rates because it matches capital recovery with consumption of plant better than the ALG procedure; the ELG methodology fully accounts for the expected life of each item in the vintage to develop an accurate depreciation rate, while the ALG method produces a less accurate averaged rate. Additionally, it is clear that the ELG methodology is not a form of accelerated depreciation. Rather, whether the speed of capital recovery under the ELG procedure is quicker or slower than under the ALG procedure is really a function of the life of the asset, as it should be. Moreover, Duke Energy Indiana has utilized the ELG methodology for its depreciation studies since the early 1990s. As Mr. Spanos pointed out, changing from the ELG back to the ALG methodology would result in shifting costs from today's customers to future generations of customers. Accordingly, we approve the Company's proposal to continue the use of the ELG procedure to calculate its depreciation rates.

With regard to the issues surrounding the calculation of terminal net salvage estimates, we note that no party has proposed depreciation rates without terminal net salvage estimates, and, accordingly, no party appears to disagree with the concept of including terminal net salvage in depreciation rates. Instead, the differences are related to components of the estimated costs that are included.

Regarding the issue of whether decommissioning costs should be escalated, we note that we have previously addressed this issue too. In PSI Energy's 2004 rate case, the Commission affirmed that decommissioning costs should be escalated to the future time at which the facilities would be retired. The Commission stated:

> Mr. Spanos utilized Mr. Wendorf's dismantlement costs which are stated in 2002 dollars, and factored inflation up to the year of the projected dismantlement as a factor in his consideration, along with his analyses of historical, or interim retirements. We find Mr. Spanos' approach to be realistic and consistent with past experience. Inflation has been a fact of life in the American economy for many years. Not factoring inflation into dismantlement costs to be incurred in the future would understate those costs, with the result being that future customers would have to pay costs arising from facilities that are not serving them. This result flies in the face of matching rates with costs incurred for service, a sound ratemaking principle followed by this Commission. Moreover, current customers receive a benefit by factoring in inflation, as it may appropriately allow for a reduction in rate base because of the increased accumulated reserve for depreciation. Accordingly, this Commission finds that accounting for inflation in determining the dismantlement estimates to be used as part of PSI's depreciation rates is reasonable. (42359 Order at 71.)

We find our reasoning from this case to be equally compelling today. Inflation is a fact of life, and ignoring the reality of inflation would understate the ultimate decommissioning costs, with the result that future customers will pay for costs for facilities that are no longer serving them. The more reasonable approach, consistent with the longstanding matching principle of ratemaking, is to use the best estimates of such future costs, including inflation, to mitigate the potential for intergenerational inequity.

We note that the FERC has also ruled on this issue and found in favor of including escalation, for using similar reasoning. In a 2013 opinion, the FERC held not only that future net salvage costs should be stated at the future cost level at which they will be incurred, but that not doing so would result in intergenerational inequity. In the 2013 Opinion at paragraph 175, FERC stated:

> We affirm the Presiding Judge's finding that Entergy has demonstrated that the decommissioning cost estimate should be escalated three percent annually to the retirement dates estimated for Entergy Arkansas' steam production units. Based on the record before us, we agree with the Presiding Judge that it is reasonable for the current decommissioning costs to be inflated to reflect future costs of decommissioning at the time of retirement in order to avoid intergenerational inequities between current and future ratepayers.[29]

The only issue is whether to use Mr. Spanos' 2.5% inflation estimate, or Mr. Andrews' 2.0% estimate. Based on the evidence presented in this case, we find that Mr. Spanos' 2.5% inflation estimate is more realistic and should be used. Mr. Spanos supported his estimate with CPI data going back to the 1960s, as well as more relevant Handy-Whitman index data, while Mr.

---

[29] FERC Opinion No. 523, issued January 8, 2013, pp. 76-77, P. 175.

Andrews' supported his inflation estimate with arguably selective time periods that are not representative of future conditions.

Next we address the parties' contention that contingency be removed from the decommissioning study. We disagree with the parties that the circumstances here warrant such removal. Commission precedent supports the inclusion of contingency and we find it reasonable and appropriate again here. Similar to our previous holdings, we give weight to the fact that the 20% contingency factor used in this demolition cost studies is conservative compared to the 25% contingency factor we approved in the Company's most recent rate case. Furthermore, the assumption that the sites will be remediated to industrial condition, rather than greenfield condition, is also conservative. We therefore decline to depart from our previous practice.

Regarding the parties' arguments that inclusion of the cost to address end-of-life inventory at retired generating plants as part of the decommissioning of a generation site, we are unpersuaded that these costs are not true costs associated with decommissioning a generation site and should not, therefore, be included in the Company's estimate of decommissioning its generation. Instead, we agree with the Company witnesses that as more and more coal-fired generation retires and is not replaced with additional coal-fired generation, it seems obvious that there will obsolete inventory remaining at the time of generation retirements, despite the Company's best efforts to put all such inventory into use. We understand that there can be limits on the ability of the Company to transfer inventory, say from Gallagher Station to Gibson Station when Gallagher retires in 2022. The equipment is presumably of different vintages and, as Mr. Mosley explained, the spare parts that fit Gallagher's coal mills do not fit the mills at Gibson or Cayuga. The Commission recognizes that the cost of addressing inventory remaining at the time of a generating station retirement is a cost of decommissioning that unit – just as disposing of remaining oil and other chemicals would be. We also agree with the Company's position that, just like plant equipment, recovery of such end-of-life inventory over the remaining life of the plant is preferable to asking future generations of customers to pay for inventory at plants they did not take electric service from. We, therefore, find it reasonable to include inventory in the decommissioning study in this proceeding.

(B) **__Estimated Useful Lives of Mass Property__.** OUCC witness Garrett took issue with certain of Mr. Spanos' recommended mass property service lives. OUCC witness Garrett proposed changes to the service lives of four transmission and distribution plant accounts, specifically: Account 353, Station Equipment; Account 356, Overhead Conductors and Devices; Account 367, Underground Conductors and Devices; and Account 369, Services.

Mr. Garrett addressed his proposed longer service lives for mass property accounts. He explained that the term "mass property" refers to the Company's grouped assets, such as those in its transmission and distribution accounts. He stated that through depreciation expense, a utility recovers the original cost of its plant assets over the average service life of those assets. He stated that when service life estimates are extended or reduced, depreciation rates decrease or increase accordingly. He testified that several of the average service lives proposed by Mr. Spanos for the Company's mass property accounts were shorter than what was otherwise indicated by the historical retirement data for these assets as provided by the Company, which would result in depreciation rates that are unnecessarily high. Accordingly, he proposed longer average service life estimates for these accounts (Accounts 353, 356, 367, and 369).

Mr. Spanos testified in rebuttal to Mr. Garrett's proposals to increase the service lives further for these four mass property accounts. For three of the four accounts listed above, Mr. Spanos had recommended an increase or no change to the average service life from the current estimate. While some of Mr. Garrett's adjustments are relatively minor, for some accounts he has proposed significant increases when compared to the current estimates. For example, he proposes a 19-year increase in average service life for Account 369. In rebuttal testimony, Mr. Spanos testified that, for many of these accounts, the recommendations made by Mr. Garrett are not reasonable. Mr. Spanos stated that his recommendations result from the approach Mr. Garrett has used to develop his estimates, which is based primarily on mathematical curve fitting. This approach does not give the appropriate consideration to the mortality characteristics of the assets studied or to other factors that should be considered. Additionally, Mr. Spanos testified that Mr. Garrett's statistical analysis did not properly incorporate relevant historical data that is supportive of Mr. Spanos' estimates. Mr. Spanos explained that while both Mr. Garrett and he used Iowa type survivor curves to calculate depreciation expense and used the retirement rate method to analyze historical data, Mr. Garrett's overall approach differs. Mr. Spanos testified that his approach also differs from the correct and proper approach to estimating service lives that is set forth in depreciation textbooks such as NARUC's *Public Utility Depreciation Practices*. Specifically, Mr. Spanos testified that Mr. Garrett's testimony indicates that he believes estimating service lives is primarily a mathematical exercise in which little more than mathematical computations of historical accounting data will result in reasonable estimates. Mr. Spanos emphasized that this overall approach is incorrect; depreciation, and particularly estimating service lives, is a forecast of the future rather than a calculation of what has happened in the past.

We recognize that while the past can help in predicting the future, the future is not exactly a repeat of the past. Informed judgment must be utilized in conjunction with a study of the past. We also note that Mr. Spanos is a longstanding depreciation expert, having worked in this area for over 30 years. For these reasons, we agree with Mr. Spanos that it is appropriate for his judgment to factor into the estimate of service lives; estimation of service lives should not be solely a mathematical and mechanistic exercise.

We note that authorities on the topic of depreciation, such as NARUC, are clear that estimating service lives must include a subjective component. For example, in Chapter XIII of NARUC's *Public Utility Depreciation Practices*, entitled "Actuarial Life Analysis," NARUC discusses and emphasizes the subjective nature of the process of estimating service lives. NARUC starts this chapter by explaining that the analysis of historical data is only one part of the process of estimating service lives:

> Actuarial analysis objectively measures how the company has retired its investment. The analyst must then judge whether this historical view depicts the future life of the property in service. The analyst takes into consideration various factors, such as changes in technology, services provided, or capital budgets.[26]

NARUC further explains that the process of estimating service lives must go beyond any objective measurement of the past. In describing the determination of a survivor curve estimate (referred to as the "projection life" in this passage), NARUC states:

> The projection life is a projection, or forecast, of the future of the property. Historical indications may be useful in estimating a projection life curve. Certainly the observations based on the property's history are a starting point. Trends in life or retirement dispersion can often be expected to continue. Likewise, unless there is some reason to expect otherwise, stability in life or retirement dispersion can be expected to continue, at least in the near term. Depreciation analysts should avoid becoming ensnared in the mechanics of the historical life study and relying solely on mathematical solutions. The reason for making an historical life analysis is to develop a sufficient understanding of history in order to evaluate whether it is a reasonable predictor of the future. The importance of being aware of circumstances having direct bearing on the reason for making an historical life analysis cannot be understated. These circumstances, when factored into the analysis, determine the application and limitations of an historical life analysis.[30]

Thus, NARUC strongly advises against the approach used by Mr. Garrett, stating clearly that "relying solely on mathematical solutions" should be avoided. NARUC further elaborates on the need for a subjective component to forecasting service lives:

> A depreciation study is commonly described as having three periods of analysis: the past, present, and future. The past and present can usually be analyzed with great accuracy using many currently available analytical tools. The future still must be predicted and must largely include some subjective analysis. Informed judgment is a term used to define the subjective portion of the depreciation study process. It is based on a combination of general experience, knowledge of the properties and a physical inspection, information gathered throughout the industry, and other factors which assist the analyst in making a knowledgeable estimate.[31]

Accordingly, we find that Mr. Spanos' estimated mass property service lives should be adopted, and Mr. Garrett's differing estimated lives should be rejected.

(C) Estimated Useful Lives of Generating Units and IRP Issues.

(I) Petitioner's Evidence. Duke Energy Indiana witnesses Pinegar and Pike testified regarding the useful lives of the Company's generating stations. Mr. Pinegar indicated that one of the rate increase drivers included transitioning to a cleaner generation portfolio in a reasoned and moderated fashion. The moderate transition plan the Company included in its depreciation rate request does increase costs to customers now, but in the long run this transition plan will be lower cost to customers given how heavily dependent on coal the Company's existing generating fleet is today and given the risk associated with likely future federal greenhouse gas regulation. Mr. Pinegar opined that it was becoming clear that greenhouse gas emissions, like carbon dioxide, are the next emission to be regulated, and that there is no proven economically feasible technology today to significantly reduce carbon dioxide emissions from coal-fired power plants. As such, the useful lives of coal-fired assets are declining in relation to what we may have thought they would be 15 or even five years ago. Mr. Pinegar explained Duke Energy Indiana is not proposing to retire any coal-fired generation prematurely – these assets have

[30] National Association of Regulatory Utility Commissioners, *Public Utility Depreciation Practices*, 1996, p. 126.

[31] Id. at 128.

already outlived their initial intended useful lives. Rather, Duke Energy Indiana is proposing to shorten the estimated useful lives of its Gallagher, Cayuga and Gibson Generating Stations' coal-fired units from an average of 65 years to an average of 58 years. He indicated that this proposed orderly transition plan increases costs gradually over time in recognition that a transition to cleaner energy is taking place and likely to accelerate in the not too distant future.

Company witness Pike explained what impacts the useful life of coal generating assets, including technical and economic factors. Key technical factors include the initial robustness of the design and construction of the unit; what environmental controls are original versus what environmental control retrofits or replacements occur in the life of a unit; the operational duty of a unit; the type and quality of the coal burned; and how well maintained the unit is. Key economic factors include fuel costs and unit efficiency; incremental environmental regulations' investment requirements; the evolution of competing technologies providing lower cost capacity and energy options; and the evolution of the regional transmission operator market, which provides potential short-term options for the management of energy and capacity needs.

Mr. Pike explained that relatively new units are being proposed for retirement in the industry primarily because their environmental controls are either original equipment or were early retrofits and are at the end of their useful lives. Whereas older boilers and turbines with newer environmental control retrofits may have life left to give. Mr. Pike indicated that other high-profile developments in the industry are climate change and carbon emission risk. There are no proven cost-effective retrofit control technologies like SCRs and FGDs for carbon and there is no such thing as "low carbon" coal. With the combination of these factors, the industry is moving toward managed, staged retirement of coal units sooner rather than later, as a means to manage the carbon footprint risk and to reflect changing economic conditions.

Mr. Pike compared the lives of coal units across peer utilities, finding the average of proposed or recently executed retirements for coal units has been reduced from about 59 years of life to about 51 years of life, with the earliest retirement at 33 years of life, and the latest at 75 years. He then compared the Company's existing retirement dates from its last depreciation study completed in 2011 to the updated retirement dates Duke Energy Indiana has included in its new depreciation study filed in this proceeding based on the moderate transition plan included in its IRP. On average, the expected life in the last depreciation study of the coal units (excluding Edwardsport) was approximately 65 years, whereas the updated retirement dates in the depreciation study for this proceeding, the average life of the coal units decreases to approximately 58 years, ranging from 47 years to 64 years on individual units. He concluded that overall, the updates to the average lives, and the range of lives for individual units proposed by the Company are directionally consistent with industry trends.

Mr. Pike then testified that Duke Energy Indiana filed its 2018 IRP with the Commission on July 1, 2019, and over the twenty-year planning horizon of the IRP, the updated depreciation retirement dates proposed in this proceeding are aligned with the Company's preferred portfolio. Mr. Pike next opined that from a technical perspective, the Company's preferred portfolio is an ordered and logical management of the end of life of the Company's generation assets, considering individual unit circumstances and reasonable practical constraints.

Mr. Pike explained that, regarding Cayuga Units 1-2, the prior depreciation study indicated a useful life of about 65 years with split retirement dates at 2035 and 2037, respectively - these dates better mirror the state of the industry then, rather than now. In addition, the split retirement dates for the units are not practical and do not reflect how the station should actually be retired from a technical, economic and pragmatic standpoint, because leaving only one unit operating at the site would result in a significant loss of economy of scale in operations and maintenance costs, and the Company has a Commission approved agreement to provide steam to the neighboring industrial customer, which requires two units for reliability.

Mr. Pike indicated that the Cayuga Station (Unit 1-4) block size is 1,085 MW, which would be ideal to replace with a new large scale natural gas combined cycle unit. This technology would continue the reliable industrial steam service with two (or more) CTs with heat recovery steam generators, and including a duct burner effectively replaces the equivalent peaking capacity of the Cayuga diesel and Unit CT4. Cayuga Station is located approximately only ten miles from a large-scale interstate natural gas pipeline that would provide adequate fuel supply for this unit. And, being a brownfield site, Cayuga could use emissions netting credits of the retiring units for purposes of permitting the new units, as well as retaining and reusing the transmission interconnect service on-site at Cayuga Station. Whereas, if new large-scale generating assets are not sited at Cayuga, then there could be required transmission system upgrades to manage the impact to the grid of the retirement of the facility.

Mr. Pike concluded his testimony on Cayuga by indicating that the retirement date for Cayuga Units 1-4 in the IRP preferred portfolio and in the new depreciation study is 2028. This results in lives of 58 years for Cayuga Unit 1, 56 years for Cayuga Unit 2, 56 years for the Cayuga Diesel, and 35 years for Cayuga Unit CT4. The resulting lives of the Cayuga coal Units 1-2 are in the mid-to-high end of the range of our peers.

Next, Mr. Pike turned to a discussion of the Company's Gibson Units 3-5, wherein the prior depreciation study indicated a useful life of about 66 years, with retirement dates of 2043, 2044, and 2047 respectively. Again, these average life expectations better reflect 2010 industry conditions than current day expectations. Of critical importance in planning the retirement of these units is the age of their environmental controls. While both the Gibson 4 and 5 scrubbers have undergone mechanical refurbishment and upgrade work in the past, the vast majority of all structural elements, including the stacks, and accompanying reagent preparation and waste product fixation systems are original. The higher sulfur dioxide emission rates from these units, along with their shorter stacks, could also expose them to more risk from potentially more stringent environmental regulations over time. Should the Company need to replace these scrubbers with new technology, the cost would be prohibitive. Complicating this, however, is the fact that Gibson Unit 5 is a jointly owned unit, which means that Duke Energy Indiana does not have sole decision-making authority over this unit. Therefore, very thoughtful planning discussions with the Joint Owners will be required to execute its retirement.

Mr. Pike indicated the IRP preferred portfolio shows Gibson Unit 4 retiring first, in 2026. This unit is then replaced by renewables, mostly solar with some wind in the preferred portfolio, helping to rapidly add diversification to the Duke Energy Indiana generating fleet. Retiring Gibson Unit 5 first would provide only half of that amount of diversification benefit for customers, Duke Energy Indiana's ownership share, while leaving the Joint Owners needing to replace their capacity shares. Additionally, because the Gibson 4 scrubber is newer, the Company proposed to keep the Unit 4 scrubber in operation and re-route the flue gas from Gibson Unit 5 into Gibson Unit 4's scrubber.

Gibson Station is the largest single generation facility in the Duke Energy fleet, and is also the largest facility in the State of Indiana. As such, it is difficult to conceptualize retiring the entire station at once. Additionally, the Gibson Station site has very limited access to natural gas fuel, and as such is not a good candidate location for large scale replacement natural gas-fired generation. Therefore, the Company anticipates having to make some transmission system upgrades as the unit retirements at Gibson Station progress, which could have significant lead time to plan, permit and execute. As such, the Company expects that staging the retirement of the Gibson units will help spread out this burden and facilitate management of the transmission system reliability. The retirement dates for Gibson Units 4, 3 and 5 reflected in the IRP preferred portfolio are 2026, 2034, and 2034 respectively. This results in lives of 47 years for Gibson Unit 4, 56 years for Gibson Unit 3, and 52 years for Gibson Unit 5.

Mr. Pike explained that resulting lives of Gibson Units 3 and 5 are again right in the mid-to-high end of the range of our peers, and the life of Gibson Unit 5 has been increased by re-using Gibson Unit 4's scrubber. One unit must be the one to go first, and based on current conditions and known constraints, Gibson Unit 4 is that best candidate unit. That said, there may be technical advantages to retiring all of Gibson Unit 5 first and avoiding the complexity of a tie-in flue-gas duct to continue using the Unit 4 scrubber. Mr. Pike indicated that if agreement on the retirement can be reached with the Gibson Unit 5 Joint Owners, that could be a reasonable option.

Next, Mr. Pike discussed the new retirement dates for Gibson Units 1-2 of 2038, which gives those units the longest life expectation of any of the scrubbed units at 62 years and 63 years respectively. He explained that these retirements remain outside the 20 year window of the IRP preferred portfolio, and hence have not been explicitly analyzed. The prior depreciation study showed these units having a useful life expectation of about 66 years. With few exceptions, the Gibson Units 1-2 would achieve the longest life of any of the other remaining scrubbed coal units with retirement dates identified among peer utilities. Mr. Pike explained that due to the make of the units on the site, separating the retirements in this grouping will enable efficient management of the site while Units 3-5 may be undergoing decommissioning and demolition activities. Further, the Gibson Unit 1-2 scrubbers are the newest installed at the site and the precipitators continue to be in excellent mechanical and electrical condition today. As such, notwithstanding that Gibson Units 1-2 have the oldest boilers and turbines at the site, the age, condition, and performance of their environmental controls, along with other inherent operating efficiencies, dictate they be retired last and together.

Mr. Pike explained that the 2018 IRP found that across the range of future scenarios and generation portfolios analyzed, it made sense to maintain operation of at least a couple of coal units past the twenty-year planning horizon, even in scenarios more adverse to coal. Said differently, not all of the coal units were economically retired in the twenty-year period. As, such the retirement date assumptions for Gibson 1 and 2 are reasonable.

Next, Mr. Pike discussed other units that were outside of the 20 year IRP study window, such as Edwardsport IGCC, most of the simple cycle CTs, Markland Hydro, and the new solar facilities. He explained that for Edwardsport IGCC, being the newest large scale generating unit in the fleet, the retirement date assumption was not changed from the date previously approved in Cause No. 43114 IGCC-8.

Mr. Pike explained that the climate change issue in general, and carbon dioxide emissions from our coal generating fleet in particular, weigh heavy on Duke Energy's future planning. This is being driven primarily based on three evolving sets of circumstances. First is the likelihood that an economic signal will be imposed at some point on CO_2 emissions through federal or other policies. Second is the fact that customer, investor, and other stakeholder expectations have been increasing that Duke Energy and peer utilities should be working to significantly reduce CO_2 emissions, sooner rather than later, whether there is a governing federal (or other) policy or not. And third is Duke Energy's own corporate commitment to reduce its overall carbon footprint. He discussed the U.S. Environmental Protection Agency ("EPA") finalization of the Affordable Clean Energy ("ACE") rule, which seeks to reduce CO_2 emissions from existing coal-fired steam electric generating units. Mr. Pike explained the overall impact of the ACE rule on the Duke Energy Indiana generating fleet will likely be relatively small from an investment perspective, although the Company will have to learn how to operate under the new CO_2 emission rate limits. Also, Gallagher will be retired before the implementation plans would take effect, and the ACE rule is not applicable to Edwardsport IGCC. Additionally, Mr. Pike noted it is impossible to predict what if any legislation or regulation regarding climate change may come to fruition in this or any future Congress or administration. However, it is clear that acting now to reduce carbon dioxide emissions on the system will better prepare the Company for any legislation or rules that are ultimately enacted, and reduce the cost of compliance in the long term.

Mr. Pike indicated Duke Energy's customers, investors, and other stakeholders continue to press the Company for carbon emission reductions, and to provide more options for low- or zero-carbon energy. As detailed in Duke Energy's 2017 Climate Report to Shareholders, the Corporation, as a whole, has reduced its CO_2 emissions by 31 percent since 2005, and has set its sights on even greater progress. In 2017, Duke Energy established a goal to reduce total CO_2 emissions by 40 percent from 2005 levels by 2030. But that doesn't mean Duke Energy intends to stop there. Beyond 2030, the Company's long-term strategy will continue to drive carbon out of our system.

Finally, Mr. Pike testified that Duke Energy Indiana's 2018 IRP preferred portfolio is a thoughtful first step towards meeting the changing expectations of our stakeholders and reducing our CO_2 emissions in the state. Duke Energy Indiana believes it would be risky for it and its customers to simply wait for carbon policy to happen. Making moderate shifts in the expected remaining lives of our coal-fired assets is a reasonable action to take now, while the Company continues to monitor the changing industry landscape and impacts of market forces.

(II) **OUCC Evidence.** The OUCC did not take issue with the retirement dates of coal generating units included in the development of the Company's proposed depreciation rates or the Company's IRP.

(III) **Intervenors' Evidence.** Of the intervening parties, the Sierra Club, Joint Intervenors, and Wabash Valley provided testimony related to the retirement dates of coal units and the Company's IRP.

Sierra Club's witness Comings concluded that the Edwardsport IGCC plant is uneconomic and should be retired as soon as possible. Duke Energy Indiana is seeking to include $300 million in costs for Edwardsport in 2020 alone. This includes $146 million in O&M, $103 million in fuel costs, and $51 million in capital costs. He testified that the plant is clearly uneconomic as it loses money on the energy market and has more expensive fixed costs than those from replacing it—much higher fixed costs than a typical coal unit. He claimed there is no economic justification for continuing to operate this plant, yet the IRP does not consider its retirement before 2045—twenty six years from now. He concluded that Edwardsport costs should be denied and the Company should develop a plan for retiring the plant. Once the Company develops such a plan, then the Company may recover prudently incurred costs prior to retirement.

Mr. Comings estimated that on a variable basis alone (i.e., excluding fixed costs) the Edwardsport plant has lost ratepayers $93 million from 2016 through 2018. These losses are caused by: 1) Duke Energy Indiana operating most of the plant as "must run" instead of MISO economic dispatch and 2) Duke Energy Indiana bidding in the plant below its variable costs. Second, the plant's fixed costs of operation are higher than those of replacing it. The combination of these findings is a clear indication that the plant is uneconomic and should be retired as soon as possible. Mr. Comings testified that MISO capacity purchases could fulfill the Company's capacity need for an infinitesimal cost compared to the costs of Edwardsport. In the meantime, long-term replacement options should be pursued that would be lower-cost than combustion turbine replacement—on a fixed and/or variable cost basis.

As to Edwardsport, Mr. Comings concluded the Commission should deny the Company's request for Test Year capital, fuel, and O&M for Edwardsport because the Company cannot meet its burden to show that those costs are prudently incurred. The Commission should not allow the Company to charge ratepayers substantial fixed costs for a plant that is nearly always uneconomic to operate on a variable basis and would save ratepayer money if replaced. Once the Company develops a plan for the plant's retirement, it should be permitted recovery of fixed costs that have been adjusted to plan for imminent retirement. (If the Commission does not agree that there is evidence that the plant should retire, then it should compel Duke Energy Indiana to conduct a retirement assessment, comparing continued operation of the plant to all available replacement options.)

Next, Mr. Comings indicated the Company's recent IRP does not justify the Company's fixed retirement dates because it fails to consider near-term economic retirement for most of its units. Without such an analysis, it is unclear if Duke Energy Indiana and its ratepayers should continue to invest in these units. Mr. Comings believed the Cayuga and Gibson units should be evaluated for retirement prior to 2024. The Company should consider robust retirement options for all its remaining coal units as soon as possible in order to assess whether these units have going-forward value for customers. The Company should also conduct an all-resource RFP and evaluate replacement options for these units.

Mr. Comings testified the Company's IRP analysis was severely limited in its economic evaluation and erred on the side of keeping older coal units operating. If the IRP analysis had concluded that some units should retire in the near-term then, in anticipation, the Company could ramp down spending on capital and operating costs in this rate case. Because of the connection between the IRP and the rate case, and because the Commission does not hold an evidentiary hearing and typically does not approve or deny the IRP around the time it is filed, this rate case affords the opportunity to rule on long-term planning issues.

Mr. Comings believes the IRP analysis that led to the Company's proposed retirement dates was flawed. First, the IRP failed to even consider retirement of Edwardsport within the 20-year analysis period, even though the plant is costing ratepayers a significant amount of money. The Company also did not consider retirement of Cayuga or Gibson units prior to 2024. Second, the IRP also fails to consider competitive bidding for new resources that could compete with existing resources, as Northern Indiana Public Service Company (NIPSCO) did in its most recent IRP. As such, regarding Cayuga and Gibson, Mr. Comings concluded the Company should be compelled to evaluate all reasonable options for retiring these units, including allowing for retirement prior to 2024 and pursuing lower-cost replacement options—such as through an all-resource RFP.

Joint Intervenor witness Sommer provided testimony specific to the Company's 2018 IRP and included a draft report as Exhibit ALS-2. She concluded that Duke Energy Indiana's 2018 IRP was irredeemably flawed in a number of respects including but not limited to: 1. Duke Energy Indiana applies its reserve margin requirement to all months of the year rather than just the MISO coincident peak; 2. Duke Energy Indiana requires the model to self-supply capacity in all months of the year rather than purchasing from other utilities; 3. The Company tries to solve the problem of unrealistic market purchases by imposing a hurdle rate on purchases, but this is a "band-aid" solution and an imperfect and inadequate one at that; 4. Coal unit retirements are unnecessarily limited to 2024 or later and only to the Company's existing pulverized coal units; 5. Duke Energy Indiana's energy efficiency bundles are unreasonably high in cost and suffer from other flaws that prevent the selection of the optimal portfolio of energy efficiency measures; 6. Capital costs for renewables are higher than is justifiable; 7. Capital costs for combined cycles is lower than is justifiable; 8. Wind and battery storage is limited to 250 MW per year without basis; 9. A $5/MWh adder for new solar resources is based on a study for Duke Energy's Carolina service territory that has no relevance to Indiana and was rejected by the North Carolina Utilities Commission; 10. Duke Energy Indiana refused to provide copies of the System Optimizer and Planning and Risk model manuals except in person despite having done so in its prior IRP; 11. The Company did not deliver the modeling files required for the Technical Appendix in Indiana's IRP rule; and 12. Duke Energy Indiana's pre-IRP stakeholder process was frustrating in a number of respects including the tendency to push stakeholder recommendations off to the next IRP filing.

Ms. Sommer concluded the 2018 IRP as filed and relied upon by the Company in preparing its case-in-chief in this docket is significantly deficient and, therefore, is not a reasonable basis upon which the Commission should rely for decisions.

Joint Intervenor witness Schlissel testified that as a result of his review of the Company's IRP as filed, the numerous Company responses to CAC's informal and formal discovery responses regarding the IRP in the IRP process and in this base rates case, and the preliminary Energy Futures Group report critiquing the IRP and the modeling process utilized by the Company in preparing it, he has concluded as follows: 1. The 2018 IRP as filed and relied upon by the Company in preparing its case-in-chief in this docket is significantly deficient and, therefore, is not a reasonable basis on which the Commission should rely for the appropriate, economics-based retirement date for Edwardsport being 2045. For this reason, the Commission should not rely on a retirement date of

2045 in setting a depreciation schedule for Edwardsport for ratemaking purposes in this proceeding.

Mr. Schlissel opined that, as filed and amended, the Company's case-in-chief did not disaggregate Edwardsport cost and revenue requirements data on a stand-alone basis, with limited exceptions for specific accounting adjustments relating to a capitalized parts and equipment inventory and capitalized and amortized outage costs associated with the so-called "Major Outage" which the Company expects to occur every seven years. The Company's case-in-chief does include some Edwardsport-specific operating performance data in the testimony and attachments of witness Gurganus, but the monthly operating performance data provided by witness Gurganus ends with June 2019 whereas he needed comparable data through September 2019 for his testimony and attachments planned for filing on October 30, 2019.

Wabash Valley witness Wilmes testified that Duke Energy Indiana, Wabash Valley and IMPA jointly own Unit 5 of the Gibson Generating Station with the following ownership interests: Duke Energy Indiana 50.05%, Wabash Valley 25%, and IMPA 24.95%. As joint owners, these parties all should have input into any decisions regarding the retirement of Gibson Unit 5. Mr. Wilmes disagreed with Company witness Pike's assertions regarding the retirement date of Gibson Unit 5. Rather, Wabash Valley supported retiring Gibson Unit 5 in the 2026 timeframe because it would be consistent with the power supply goals of Wabash Valley and would also avoid the expense of re-routing the flue gas from Gibson Unit 5 to Gibson Unit 4's newer scrubber. He further indicated that Wabash Valley will fully cooperate with Duke Energy Indiana and IMPA in the procedures necessary to retire Gibson Unit 5 in the 2026 timeframe. Mr. Wilmes also testified Wabash Valley supports the Commission's approval of the accelerated depreciation on Gibson Unit 5 as may be necessary to retire that unit. To the extent that Petitioner has requested accelerated depreciation of Gibson Unit 4, in accordance with Table 2 provided on page 12 of witness Pike's testimony, Wabash Valley would support a comparable accelerated depreciation timeline for Gibson Unit 5. Mr. Wilmes indicated that Wabash Valley has a diverse power supply portfolio and is constantly replacing and adding additional resources to its supply. In recent years Wabash Valley has added over 200 MW of Wind generation and 400 MW of Solar generation. Finally, he indicated that he had communicated Wabash Valley's position on the retirement of Gibson Unit 5 to IMPA, and IMPA has represented that its position is the same.

Wabash Valley witness Smardo, Executive Vice President of Energy Solutions for IMPA, provided testimony substantially similar to Mr. Wilmes, indicating that IMPA supports retirement of the jointly owned Gibson 5 Unit in the 2026 timeframe because it would be consistent with the power supply goals of IMPA and would also avoid the expense of rerouting the flue gas from Gibson Unit 5 to Gibson Unit 4's newer scrubber.

IG witness Mr. Andrews remarked that Duke Energy Indiana found some errors in its IRP. He testified that retirement dates from the preferred portfolio of the 2018 IRP are direct inputs to the depreciation rate calculations in the Company's depreciation study, and early retirement of Gibson, Cayuga, and Gallagher coal plants accounts for $131.7 million of the $145 million test year depreciation expense increase. Therefore, he opined a change to the optimal retirement dates for these plants could have significant impacts on the depreciation rates and thus the revenue requirement in this proceeding. While the Company attempted to minimize the impact in the error, it has not verified that claim. Further, this imprecision further supports Mr. Andrews' recommendation to utilize the ALG method, which better addresses the uncertainty of generation unit retirement dates.

Mr. Andrews also indicated that Duke Energy Indiana did not consider the accelerated depreciation expense associated with the early retirement of its coal plants in the IRP analysis because it used a metric called the Net Present Value Revenue Requirement ("NPVRR"). He stated that if a portfolio requires the early retirement of any plant and the models do not account for the increased depreciation expense, then the NPVRR coming out of those models does not allow for an accurate comparison of portfolios.

(IV) <u>Petitioner's Rebuttal Testimony</u>. The Company provided the rebuttal testimony of Messrs. Pinegar, Pike, Gurganus, and Park regarding the coal unit retirement and IRP issues. Mr. Spanos also commented on the issue, noting that the Company's estimated retirement dates were consistent with the industry. Mr. Pinegar explained the Company took a moderate transition approach to its coal retirements included in the 2018 IRP and in depreciation rates proposed in this proceeding. He indicated that there are many good reasons for a moderate transition, not least of all being the impact to local communities where these coal plants have been located. The community impacts range from property taxes, coal mining jobs, generating plant jobs, and other related industries in the locale. Mr. Pinegar expressed the Company's belief that its balanced approach allows communities time to transition and prepare for a future without the coal plants operating.

Mr. Pike responded to the recommendation by Wabash Valley and IMPA to retire jointly owned Gibson 5 by 2026. He indicated the Gibson Unit 5 Joint Ownership Agreement requires unanimous agreement among the owners in order to retire the unit, and that achieving a consensus on the retirement date is a capital opportunity for Duke Energy Indiana that should not be dismissed. To the extent there is no material difference in the cost or performance of Gibson Unit 4 and Gibson Unit 5 (other than the Unit 5 scrubber), and the proposed scrubber flue gas crossover duct would be eliminated, Mr. Pike indicated the Company can fully support Wabash Valley's and IMPA's recommendation. As such, Mr. Pike indicated that the Company would be amenable to a simple swapping of the retirement dates of Gibson Units 4 and 5. So, Gibson Unit 5 would retire in 2026, and Gibson Unit 4 would retire in 2034 along with Gibson Unit 3 and Noblesville. Accelerating Gibson Unit 5's retirement date without also deferring Gibson Unit 4's retirement date would result in a further increase in depreciation expense in this proceeding, which would be undesirable for customers, and is unnecessary at this time. Duke Energy Indiana witnesses Mr. John Spanos and Ms. Diana Douglas present the impact of this change on depreciation rates and expenses in their rebuttal testimonies.

Mr. Pike explained that because Duke Energy Indiana only owns about half of Gibson Unit 5, swapping the retirement dates of Gibson Units 4 and 5 will reduce the Company's capacity need by 2026 in half, slowing the pace of diversification, and decreasing Company carbon emission reductions. However, the opportunity to capitalize on unanimous agreement with the Gibson Unit 5 Joint Owners has more immediate value to customers. Absent this agreement now, there would be uncertainty even in the original proposed retirement date of 2034. Further, if Duke Energy Indiana objected now and held out its option to continue to operate the unit, the long-standing productive relationship we have had with the Joint Owners could become stressed, impacting other business relationships, such as wholesale, that are beneficial for retail customers. Additionally, the change is not expected to materially impact the Company's carbon emission reduction goals.

Mr. Pike then provided an update on the Company's carbon emissions reduction goals, which were announced on September 17, 2019. The 2030 carbon emission reduction goal has been increased from 40% to "at least 50%," still from a 2005 emissions baseline. Second, consistent with more recent goals announced by peer utilities, Duke Energy has established a second-phase goal. This second-phase goal is for "net-zero" carbon emissions by 2050. Mr. Pike indicated the new Duke Energy 2030 corporate climate goal was informed by the results of the 2018 Duke Energy Indiana IRP. The Cayuga Station and Gibson Unit 4 retirements as shown in the preferred portfolio in 2028 and 2026 respectively would support the Company in meeting the new 2030 goal. While Company-owned carbon emissions in 2030 will increase versus the IRP preferred portfolio, all else the same, a swapping of the Gibson Unit 4 and Gibson Unit 5 retirement dates should not materially impact the ability to achieve this goal. Again, the goal is corporate-wide, so ebbs and flows in emissions will be strategically managed across the enterprise.

Mr. Pike concluded this issue by indicating that the swapped retirement dates for Gibson Units 4 and 5 result in lives of 55 years for Gibson Unit 4 and 44 years for Gibson Unit 5, and that both lives are reasonable, and are in line with the range seen in industry based on unit-specific circumstances.

Mr. Pike next addressed concerns expressed by the Sierra Club and Joint Intervenors regarding the Company's IRP and coal retirements. He indicated the fundamental purpose of the IRP in this proceeding is to support reasonable depreciation rates for the Company's generation assets. Duke Energy Indiana is not requesting any type of formal approval of future generating unit retirements, nor pre-approval of future new generation resources in this proceeding. There are no notable resource actions planned between now and the time the Company will file its next IRP in 2021, when the system will be re-evaluated again. Mr. Pike believed the Sierra Club and Joint Intervenors are attempting to use their criticisms of the IRP as a platform to advance their own radical agenda of shutting down coal-fired generating units as fast as possible, whether or not that is in the best interests of customers. It would clearly be a great disservice to customers to assume such dramatic coal unit retirements as implied by Sierra Club and Joint Intervenors in this proceeding – it would only go to dramatically raising depreciation expense and is unnecessary at this time. Mr. Pike noted that Sierra Club and Joint Intervenors are the only parties that seem to protest the IRP preferred portfolio as unreasonable. Other interests, such as the witness for the Indiana Laborers District Council, Mr. Frye, espouse the negative impacts on the workforce and the economies of local communities from accelerated plant shutdowns. And, other intervenors, such as the OUCC and Industrial Group, generally do not take issue with the planned retirement dates. The Company's goal is to find a balance that takes measure of all of the implications of our proposed resource plan, and the Company's preferred portfolio does that.

Mr. Pike responded to Mr. Comings' contention that the Company's coal units are more expensive to operate than other alternate resources. He indicated that Mr. Comings focuses on a dollar per megawatt-hour ($/MWHR) energy cost metric, which is a flawed and meritless comparison. A simple "profit-and-loss" analysis does not constitute resource planning. Rather, Duke Energy Indiana is obligated to provide service to customers 24x7x365. Mr. Comings' premise would have the Company shut down our high capacity factor dispatchable coal-fired units (and presumably everyone else's similarly situated fossil-fuel units in the State and elsewhere), and replace them with market purchases, peaking units, or other alternatives (presumably solar and/or wind resources) as that would purportedly be a lower cost. However, Mr. Pike opined that this would clearly not provide equivalent energy resources to the system. In addition, ironically, Joint Intervenors witness Ms. Sommer's report on the 2018 IRP conversely alleges that the market purchases in the modeling portfolios are already too high.

Mr. Pike testified that a clear shortfall in Mr. Comings' analysis is his failure to address market depth in any way. If Duke Energy Indiana were to remove its dispatchable coal generation from the market, the market price would most certainly have to increase to incent its production from other resources. This would erode purported cost savings and risk the reliability of the grid.

Mr. Pike explained that if the Company followed Mr. Comings' premise further and installed all solar energy resources, for example, this would result in everyone having lights on and access to power during the day (assuming that day is sunny), and everyone having no power at night. While this simple example would perhaps have achieved Sierra Club and Joint Intervenors' goal of purportedly lowest cost of energy, such a scenario obviously fails miserably from a resource planning perspective. To remedy this 24x7x365 service deficiency, the system would have to be bolstered with additional resources, as well as extended-range energy storage, rapidly eroding the Sierra Club and Joint Intervenors' contention of lowest cost. Mr. Pike explained that simple profit-and-loss analyses are not instructive for resource planning. The goal of resource planning is not merely to find the lowest cost system, but rather to find the lowest cost system that can actually succeed in serving customers reliably.

Next, Mr. Pike addressed Ms. Sommer's complaint that Duke Energy Indiana included a limitation in its IRP of 2024 for the earliest coal unit retirements relying in part on the need for potential transmission investment. It is true that Duke Energy Indiana established assumptions regarding coal unit retirement transmission constraints for 2018 IRP modeling purposes based on a vintage 2016 internal retirement transmission impact analysis, which was the information available at the time. And it is also true that the Company updated this study in 2019, but that it was too late to be taken into consideration in the 2018 IRP. It is further true that the 2019 study revealed fewer transmission constraints to coal unit retirements than the 2016 study. However, such transmission impacts are constantly changing as various generation and transmission projects enter and leave the MISO planning queue. The internal studies that Duke Energy Indiana performs are informal, directional, and at a point in time. Mr. Pike explained, MISO performs the actual formal transmission impact study once an entity actually files for a unit retirement, at which point such retirement becomes a non-rescindable commitment. Since it would be imprudent to commit to a unit retirement a long time in advance, the Company must rely on the internal studies as directional only, at whatever point in time they are available.

Further, Mr. Pike noted that 2024 is still a reasonable date for early coal unit retirements for IRP modeling purposes. He explained that there is much more to it than just remedying any transmission system impact. Other practical constraints and considerations include a smooth and thoughtful transition of the labor force; managing local community impacts; allowing sufficient lead-time to manage the roll-off of long-term coal contracts; allowing sufficient minimum lead-time for the construction of new dispatchable resources; managing the rate impacts to customers of dramatically accelerated depreciation; and also giving due consideration to corporate cash flow and credit constraints for funding what would be a large replacement build in a short timeframe. Quite clearly, the Duke Energy Indiana 2018 IRP preferred portfolio, as modified with the Gibson Unit 4-5 retirement date swap, spreads out the coal unit retirements in a prudent and reasonable way so as to enable effective management of these challenges.

Mr. Pike next responded to Mr. Comings' contention that Duke Energy Indiana should have a resource plan more like NIPSCO's. Mr. Pike indicated that no two utilities, let alone any two coal units, are situated exactly alike. There are very notable structural and cost differences between NIPSCO and Duke Energy Indiana that help explain why the NIPSCO coal units may be more economic to retire than the Duke Energy Indiana coal units in an IRP. Four important differences are the existing fleet makeup, degree of environmental compliance, coal supply and cost, and O&M cost rates. Mr. Pike concluded that there are clearly material differences in the structural and cost circumstances between NIPSCO and Duke Energy Indiana that make any assignment of NIPSCO's resource planning strategy to Duke Energy Indiana inappropriate and uninformative.

Mr. Pike concluded that Sierra Club and Joint Intervenors make no compelling arguments that Duke Energy Indiana's 2018 IRP preferred portfolio, as used for depreciation rate purposes in this proceeding, should not be considered reasonable by the Commission. Despite their complaints regarding Duke Energy Indiana's IRP process and assumptions, models only inform us; models do not make reasoned recommendations or decisions. The preferred portfolio is not necessarily intended to be optimized to a specific future, but rather designed to perform robustly across a potential range of futures, and take into consideration reasonable and realistic constraints, and impacts beyond raw economics. The Commission should therefore disregard Sierra Club and Joint Intervenors' unsupported recommendations for unnecessarily accelerated coal unit retirements, and approve Duke Energy Indiana's depreciation expenses as presented by Mr. Spanos and Ms. Douglas.

Mr. Gurganus responded to allegations by Sierra Club and Joint Intervenors that Edwardsport IGCC should be considered for retirement. He explained the benefits to customers of Edwardsport's generation and the benefits of it operating on both syngas and natural gas. He also explained how it would not be strategic to immediately shut down a new diverse asset that will be providing energy to customers for another twenty-five plus years after running it only six years. He explained that every year, the Plant has improved the planning and execution of its maintenance and maintenance outages, settling most recently on a modular approach, which ensures the station continues to provide net positive generation to customers while other components of the station are being maintained.

Further, he explained that the station's unique ability to run on both natural gas and coal provides diversity and reliability. Edwardsport was built to be a long-term asset for Duke Energy Indiana's customers and the Company believes it will continue to be a valued asset – shutting the station down or even just shutting down or "mothballing" the gasification island, as the Industrial Group suggests, would both result in the underutilization of a significant investment. In fact, Edwardsport has not yet completed its full maintenance cycle yet – its final outage in the first maintenance cycle will be executed in 2020 – that outage will also be the first time the steam turbine has had major scheduled maintenance. As such, the plant remains early in its useful life.

Mr. Gurganus explained why diversity of generation supply is important and how Edwardsport provides such. Today, the risks of single-fuel-source energy reliance are increasing, and it is in customers' best interests to diversify. However, diversity does not mean retire all coal and build all natural gas plants; or retire all coal and build all renewables. Rather, true diversity means an "all of the above" approach. Therefore, as the Company moves to retire its older coal-fired units, there is value in maintaining its youngest coal-fired unit – particularly one with advanced emission controls – Edwardsport IGCC, so that coal can continue to be a meaningful contributor to diversity for customers' benefit for years to come.

Next, Mr. Gurganus explained the flexibility Edwardsport provides to the system. Edwardsport is unique in that while it was designed and optimized to operate on syngas made from coal, it can also operate fueled by natural gas, or by any combination of syngas and natural gas. In addition to fuel flexibility, there are two gasifier trains, which can serve either combustion turbine or both combustion turbines, depending on what portions of the station are running.

Mr. Gurganus explained that Edwardsport was designed to produce its maximum performance when operating on 100% syngas produced from coal. From a commodity perspective, the price of coal has been less volatile than that of natural gas, remaining consistently low over the years. The Station's coal is supplied by a local Indiana mine, limiting transportation costs, and providing jobs and economic value to the local community and the state. The Company also shares in coal supply contracts with Cayuga and Gibson stations, giving the Company more flexibility in coal procurement and pricing. Procuring coal from a local mine also limits the impact from natural disasters and other political events on the price and availability of our coal, even when natural gas prices and availability can experience swings. Coal also provides a reliability and resiliency value of fuel inventory maintained at coal plants, relative to natural gas. Edwardsport's fuel diversity is not subject to the same ambient condition design limitations (wind speed, clouds, temperature, etc.) as renewable generating resources.

That said, Mr. Gurganus explained the benefits of the ability of the plant to also run on natural gas. Natural gas can be used as a secondary fuel to operate the combustion turbines when the gasifiers are undergoing planned maintenance, either individually or simultaneously or in the event of gasification forced outages or derates.

Mr. Gurganus next took issue with Mr. Gorman's premise that Duke Energy Indiana could rather easily just place the gasifiers in "cold storage for use at a later time" as a means to capitalize on low natural gas prices. In fact, such activity would be very difficult, and to really maximize the variable cost benefits, it would involve completely shutting down the gasifiers and other supporting gasification systems. Otherwise, those systems would be sitting in standby, using substantial auxiliary power to the detriment of the output and efficiency of the unit on natural gas. Completely shutting those systems down and turning them back on, however, is a multi-week-long process. It can take up to fourteen days of turnaround if all of the gasification systems are allowed to reach ambient conditions (*i.e.*, gasifiers fully cooled down, and the cryogenic components of the air separation unit fully warmed up), requiring a complete re-start of the plant. This makes it operationally difficult, time consuming, and costly to switch fuels in response to short-term natural gas price signals in an attempt to capture benefits for customers.

Further, Mr. Gurganus explained the logistical implications of a permanent or semi-permanent switch to natural gas operations. Edwardsport receives coal under contract from a local mine. If Edwardsport were to switch to natural gas for any significant length of time, the Duke Energy Indiana system would be oversupplied with coal, potentially requiring the reinstitution of the decrement process. He commented that it certainly seems nonsensical to burn natural gas, only to end up having to decrement the other coal units' costs so they will burn more coal. Over time, the Company could perhaps learn to manage this with appropriate fuel consumption forecasting and volume hedging, but this would be a near-term constraint.

In fact, Mr. Gurganus explained, truly maximizing benefits to customers of operating Edwardsport on natural gas would also require the Company to reduce staffing levels to just those needed to run the station's natural gas systems. Taking such drastic action would require a long-term view of the future and would be multiple years long, if not permanent decision. Once those specially skilled gasification employees leave, it is not likely that they would return, especially if they would be returning to an environment of job uncertainty where the Company could switch back to natural gas at any time and lay them off again. The Company would need to train new employees, assuming again, that it could even attract new employees to the plant. Considering that it took several years to really ramp up gasification operational efficiency, such a "re-boot" of gasification with an all new workforce would be extremely difficult. Therefore, shifting Edwardsport to operate on natural gas as a primary fuel is akin to making the decision to retire the gasification systems.

Mr. Gurganus further explained mothballing the gasification system would not mean shut it down and walk away. Rather, the Company would need to continue to invest in and maintain the gasification systems, protecting them from natural degradation, and ensuring ongoing operational permit compliance. Additionally, there could be Title V air permit and National Pollutant Discharge Elimination System ("NPDES") permit implications to running primarily on natural gas. The plant is permitted to operate on coal as a primary fuel and natural gas only as a secondary fuel. The permits do not contemplate operating Edwardsport on natural gas as a primary fuel over extended durations, such as years, so the permits could be required to be re-opened and the plant's environmental limits reassessed. Further, it is possible that if Edwardsport were operated on natural gas for too long, its emission baseline for operating on coal could be lost and it could be challenging to restart the plant on coal again.

Mr. Gurganus noted that many have called for a ban on the practice of hydraulic fracturing which has led to low natural gas prices, which could cause natural gas prices to rise abruptly. Therefore, for all these reasons, in Mr. Gurganus' opinion it is too soon to give up Edwardsport's coal firing capabilities given these uncertainties.

Mr. Gurganus indicated that if a decision was made to operate Edwardsport primarily on natural gas mitigation efforts would need to be considered, such as hedging the natural gas commodity price by locking in a strip of gas (volume at a price), becoming obligated to consume the fuel, and subject to downside price risk, and increasing the amount of natural gas firm transportation capacity to Edwardsport.

Finally, Mr. Gurganus opined, since 2005, the Commission has been presented with a variety of arguments regarding nearly all aspects of the station's construction and operation. While

Duke Energy Indiana has reached settlement agreements resolving some of the more major disagreements between the parties over the years, the Company has not wavered in its support for Edwardsport and its commitment to customers and to the state of Indiana and its other stakeholders to prudently and reasonably operate Edwardsport, improving first its safety and reliability and second, its efficiency. Duke Energy Indiana will continue its efforts to maintain safety and reliability, while working every day to operate the station more efficiently from a cost perspective.

Mr. Gurganus explained that the past six years of operations have led to improvements in managing Edwardsport's operations, predicting maintenance needs and avoiding forced outage events. Edwardsport has been an important investment in a technology that allows for the cleaner utilization of coal. The station is an industry benchmark both domestically and internationally for those using and interested in using the gasification technology to reduce emissions in their own processes. Duke Energy Indiana has been a great corporate partner living up to and exceeding its commitments regarding investment in the station and its communities, employment and usage of coal. Customers continue to benefit from the tax incentives provided at the inception of Edwardsport to encourage the Company to make this investment.

Mr. Gurganus and the team will continue to work through our list of degraders and other systems requiring frequent maintenance to improve reliability, reduce forced outage events, and decrease the operational and maintenance expenses.

Company witness Mr. Park next addressed the criticism of the Company's IRP process and results, both generally and in particular in relation to generating units' lives. Mr. Park began by indicating that Ms. Sommer's IRP report mischaracterizes, is misleading, and contradicts itself. As to complaints regarding reserve margins, Mr. Park indicated Ms. Sommer's report argues that having a monthly reserve margin is not realistic. However, she confuses the short-term resource adequacy view of MISO with the long-term resource adequacy that needs to be considered in the IRP, wherein the reserves must be available in every month. Further, Ms. Sommer's report fails to consider is that if the economics of the industry drive more coal retirements and solar additions, the rest of MISO will also become winter peaking for planning purposes which means that the winter peak now becomes the primary reserve margin constraint. An overall philosophy of the IRP is that the utility will plan for meeting its own resource adequacy and take advantage of MISO purchase and sales to reduce costs.

Mr. Park next addressed the report's criticism of the high level of purchases, which he indicated ignores data when it doesn't support its claim. Specifically, the "high level" of purchases is only true for some scenarios in certain years. The preferred portfolio has relatively low market purchases over the next 10 years and in some years, this portfolio has net sales. The report also tries to make a point that the $2/MWh adder that was applied to market purchases in the Company's IRP is addressing a symptom of too many power purchases. Rather, the adder is merely a model adjustment that is made to better calibrate the model's behavior with that of the real world. The $2/MWhr adder attempts to replicate the real-world issues associated with dispatching generating stations. That is, it does not make sense to shut down a generating unit and make purchases from the market the minute there is a one cent difference in costs. This adjustment replicated the real world better by recognizing real world limits.

Regarding Ms. Sommer's criticisms related to generating unit retirements, Mr. Park indicated that the report uses historical data to address unit retirements where retirement analysis should be based on prospective data and the report uses a monthly average price which completely ignores the dispatchability of the units. Dispatchable units will operate when economic and those periods will have higher average prices than the average of all hours. The report only values the capacity that these units provide at the MISO auction clearing price – a short term market price. The auction clearing price is typically very erratic and tends to be quite low and does not reflect the true value of capacity in the market and is not close to the value for capacity in the bilateral market. Further, he opined the report is also missing the cost of the other generation that would be required to maintain resource adequacy.

Regarding Ms. Sommer's criticisms of renewable pricing in the IRP, Mr. Park indicated that again, the report selectively cites data that supports its claims. Duke Energy, as part of its normal, enterprise wide business practices, engages two industry leading consulting firms to provide cost data. Renewable data is provided by Navigant and traditional resources cost data is provided by Burns & McDonnell. Furthermore, the IRP included a low-cost solar sensitivity that featured a solar cost that was approximately 35% lower than the base forecast in 2019. The important lesson from this analysis is the impact on the resource plan when the model is presented with significantly lower solar costs. In the Reference scenario, solar additions accelerated 6 years and a coal retirement retired 4 years earlier. However, in the scenario without a carbon tax, solar investment increases only slightly toward the back of the planning period and the solar investment accelerates 3 years. The lesson here is that in an environment of low gas prices and no carbon regulation, solar does not become economic until the early to mid-30s.

In response to Mr. Comings' and Ms. Sommer's suggestions that Duke Energy should have done an all source RFP to obtain renewable pricing for the IRP, Mr. Park explained the cost information that it received from the respective consultants who survey the market for quality unit cost information results in the best and least biased data set. When an RFP is issued, bidders will bid a price that maximizes their likelihood of profit. In order to do that, bidders have been known to put in a low bid for an undefined project in order to advance to the short list or win the bid outright. Once that objective has been achieved, the bidder is in a position where it can then negotiate on terms and costs that benefit them. The bid price in an RFP and the final cost is not guaranteed to be the same number, and in fact often differs. Whereas, when the Company's consultants survey they market, they are looking for transactable prices across a range of projects. This results in a more robust and unbiased estimate of costs. Further, he explained at the time of the IRP analysis, no large-scale generation projects were envisioned in the near term. Once a new generation project is needed, part of that process will include competitive bidding which will be used in the CPCN process.

In response to Ms. Sommer's criticism regarding the $5 adder for solar included in the IRP analysis, Mr. Park indicated it was included to account for the fact that as solar penetration increases, there are greater demands and investments needed on the delivery system. The report takes issue with a model enhancement that was adopted and based on an actual industry study. The report also fails to realize that just because there might be little solar in the MISO footprint right now, that will not always be the case and the IRP model is a long-term model intended to look 20 years in the future. It is well understood, that as solar penetration increases, there are additional demands placed on the transmission and distribution system to accommodate the additional intermittency.

Regarding Ms. Sommer's complaints regarding access to copyright material, Mr. Park indicated that the Company rightfully objected to providing the manuals since they contain copyrighted information belonging to third parties and the Company then offered to make these manuals available at the utility's office – an offer no party accepted.

Mr. Park next addressed Ms. Sommer's complaint that stakeholders provided numerous suggestions on modeling improvements that Duke Energy Indiana did not agree with or said it would consider in the next IRP. While this is true, Joint Intervenors are making a leap that is not consistent with the rules for the public advisory process. 170 IAC 160 4-7-2.6(c) states that "the utility should solicit, consider and timely respond to relevant input relating to development of the IRP" and 170 IAC 160 4-7-2.6(d) states that "the utility retains sole responsibility for the content of its IRP." The Company considered and responded to each of the suggestions mentioned in the report and explained why the suggestion wasn't being adopted.

Mr. Park next addressed the report's claims that the Company did not comply with the Commission IRP rules. As one example, in Table 1, the report "finds" that the Company *partially* complied with the following: "The IRP process should be developed and carried out to include stakeholder participation". This is patently untrue as six, day-long stakeholder meetings were held in addition to numerous conference calls and discovery responses.

Mr. Park disagrees with the report's recommendation that the IRP should be modeled on an UCAP basis where the output of a generating unit is adjusted for historical outages, which is how MISO measures capacity for the one-year capacity auctions. MISO determines a UCAP reserve margin that ensures resource adequacy and typically this number is in the 7-8% range as it changes every year. To apply this methodology, the utility would not only need to estimate how the UCAP reserve margin requirement will change over time, it must also estimate future unplanned outages at each of the generating units. These difficulties with modeling and estimating are never addressed by Ms. Sommer's report. Rather, Mr. Park explained, Duke Energy Indiana has continued to model the IRP on an ICAP basis where generators are given their nameplate capacity. Resource adequacy is then assured by planning to a higher 15% level. Conceptually, ICAP and UCAP are measuring the same thing. One can reduce reserve margin and increase unplanned unit outages based on difficult assumptions or one can model a higher reserve margin (again to reflect such unplanned unit outages) which has been successful for many decades. The reserve margin used by Duke Energy Indiana is also well within the range of reserve margins of other utilities across the nation. Estimating additional variables with no apparent benefit is not a good planning practice.

Mr. Park next addresses Ms. Sommer's many criticisms of the IRP's handling related to energy efficiency ("EE") despite the utility going to considerable effort in modeling EE as a supply side resource. Ms. Sommer complains the costs used in the IRP for EE are higher than historical costs. However, she fails to recognize that the program costs for the IRP were directly provided by an independent third-party (Nexant) in a Market Potential Study reviewed by Duke Energy Indiana and EE stakeholders. Next, Mr. Park explains that Ms. Sommer's methodology to calculate the Levelized Program Costs for these historical bundles is incorrect and when calculated properly, the most recent actual levelized costs are very close to those used in the IRP. Mr. Park concluded that the Company agrees that the levelized costs for the bundles beginning in 2021 are in some cases higher than the historical levelized costs. However, the costs are not as divergent from the historic levels when they are compared to the proper calculations of levelized costs using the program (or bundle) specific measure life.

Mr. Park next took on Ms. Sommer's report's contention that the Company is incorrectly treating the cumulative effect of EE measures being adopted over time by use of the half-year convention. He explained that the Company has repeatedly attempted to explain in this IRP analysis and others, in order for the IRP process to correctly evaluate the impact on the system peak load, the impact associated with the adoption of EE measures cannot all be assumed to have been added on January 1 of a given year. To do so would significantly over estimate the amount of savings available from EE measures at the time of the summer peak (assumed to occur in July). The method employed by the Company is the same method that has been used in all past IRP proceedings and it has not been questioned by the Commission in the past. Mr. Park indicated that the report fails to understand that all of the savings from each bundle are correctly accounted for because each bundle is being treated as a discrete amount of cumulative savings, but the cumulative savings from all selected bundles are added together in the final analysis used in the IRP. Ms. Sommer fails to understand that the half year of "leftover" savings are already being included in the next year of the ongoing savings from *the original bundle* and therefore would be double counted if also included in the first year of the subsequent bundle.

Mr. Park next addressed criticisms of the load forecast. He concluded that using the limited historical data and ignoring the cyclical and structural changes in energy usage, the report still only shows a difference in the average growth rate of demand of 0.26% and on energy 1.1%. In relation to the Duke Energy Indiana system, this translates to only 15 MW in a year on a demand basis and approximately 370 GWh on an energy basis.

Regarding complaints that the IRP is deficient in how it considers paired solar with storage systems, Mr. Park indicated the IRP included this technology as an option and the model was free to select multiple units of the paired resource, but did not due to economics. This is not surprising because if solar is only economic under certain circumstances and storage is economic on only location specific niche applications, pairing the resources is an even less compelling proposition.

Mr. Park next addressed the report's claims that that there are four portfolios that are lower cost than the Moderate Transition portfolio that was selected as the preferred portfolio in the IRP. What the report fails to mention is that this only true in some of the scenarios that the IRP considered. For example, the Current Conditions, Slower Innovation and Reference, No Carbon portfolios are all more expensive than the Moderate Transition portfolio in the scenarios that include carbon regulation. The report then undermines itself by criticizing the preferred portfolio in the next paragraph for not moving fast enough with regard to carbon reduction, but then goes on to criticize the preferred portfolio based on cost in scenarios without a carbon tax. Since greater carbon reductions and costs are positively correlated, it is disingenuous to criticize the preferred portfolio for its carbon reduction in one scenario and its costs in materially different scenarios. Mr. Park indicated that the preferred portfolio accelerates coal retirements and renewable additions in an unprecedented fashion for the utility despite the current absence of meaningful carbon regulation.

Finally, regarding errors identified in the IRP as pointed out by Mr. Andrews, Mr. Park indicated that the Company has regrettably identified some minor errors in the execution of the 2018 IRP; however, no process is perfect. Further, the relative materiality of the identified errors is de minimis compared to the breadth of assumptions defining the five future modeling scenarios, be it fuel prices, energy prices, technology costs, carbon regulatory programs, and more. Taken out of context, implications of the word "error" can easily be blown out of proportion, as Mr. Andrews has attempted to do. However, for numerous reasons as discussed, our selected preferred portfolio remains robust and reasonable.

In response to Mr. Andrew's criticism that the remaining net book value of existing assets in an IRP was not included, Mr. Park indicated that this is standard practice and does not dissuade from the robustness of the preferred portfolio in any way. While Mr. Andrews is correct that accelerating generating unit retirements increases the present value of revenue requirements ("PVRR") of depreciation, he failed to consider the fact that at the same time, the PVRR of the return components (equity, debt, and tax gross up) are decreasing for every year the rate base is brought forward and reduced. These affects are largely offsetting, so that the total PVRR of existing net book value (of and on) is relatively insensitive to remaining asset life. Therefore, exclusion of it from an IRP has no material impact on portfolio PVRR, nor the selection of the preferred portfolio.

Finally, Mr. Park addressed retirement of generating assets in the IRP, finding the measured retirement schedule in the preferred portfolio as very reasonable for customers. Furthermore, when measured across five different scenarios on the basis of cost, CO2 emissions and market exposure, the Moderate Transition portfolio was selected as the preferred portfolio. This portfolio is the most aggressive in terms of coal retirements and renewable additions than any previous IRP. He also indicated that after the IRP had been developed, the Joint Owners of Gibson 5 Unit approached the Company about the possibility of retiring Gibson 5 sooner, as discussed in Mr. Pike's rebuttal testimony. The Company looked into the possibility of moving the retirement of Gibson 5 to 2026 and delaying the retirement of Gibson 4 to 2034. This change has minimal impact on the PVRR of the portfolio and results in a slight rate reduction to customers. Offsetting this benefit is that it does slow down carbon reductions of the portfolio as well as renewable additions.

Mr. Park concluded his rebuttal indicating that the IRP process and results remain reasonable and most importantly a robust choice given the potential for many different future scenarios.

(V) **Cross Answer Testimony.** Joint Intervenor witness Mr. Schlissel provided cross answer testimony regarding Edwardsport IGCC. Duke Energy Indiana objected to this testimony as inappropriate cross answer testimony and the Commission allowed the testimony, finding in a January 13, 2020 docket entry:

> While we do not encourage stepping outside the bounds of proper cross-answering testimony, we find that our ability to weigh the evidence and for the specific circumstances in this proceeding, do not place DEI in a position of being prejudiced nor do we unreasonably hinder the efficiency of our administrative process.

Mr. Schlissel summarized the recommendations of OUCC witness Alvarez, IG witness Gorman and Sierra Club witness Comings regarding Edwardsport. He indicated that although he appreciated the OUCC's effort to reduce the burden that Edwardsport presents for Duke Energy Indiana's ratepayers by reducing the recommended O&M costs, there is no evidence that continued operation of Edwardsport as an IGCC would be economic even if its recoverable fixed O&M expenses were capped at the amount recommended by Mr. Alvarez.

He went on to list other factors that would need to be considered include: Edwardsport's consistent failure to achieve its 618 MW net full capacity rating; Edwardsport's poor and unreliable operating performance, especially that of its gasification system; the plant's extremely high parasitic loads; the plant's extremely high heat rate; that the plant's production costs would remain extremely high even if capped in the manner and at the level recommended by Mr. Alvarez; the Company's projected high levels of additional capital investments that would be incurred if Edwardsport continues to operate; continued low natural gas prices; Continued competition from available, low cost end-use efficiency; increasing competition from renewable resources due to declining wind and solar power purchase agreement prices, especially, but not exclusively, when combined with storage strategically sited and sized.

Mr. Schlissel testified that Edwardsport's net capacity factors have been, and continue to be, significantly lower than Duke Energy Indiana projected they would be when it was seeking and obtaining Commission approval to build the plant. Its actual heat rate is also higher than anticipated when the plant was under construction. Additionally, the Equivalent Forced Outage Rate ("EFOR") between June 2013 and October 2019 was much worse than the average EFOR of the relevant industry comparison group. Next, Mr. Schlissel opined that the gasifier availability is not reliably at 85%. As to equivalent availability, Mr. Schlissel complained that the Company has only provided the equivalent availability for the entire plant, rather than just the gasification systems. He indicated that Company data shows that Edwardsport's availability for the period June 2013 through October 2019 averaged slightly above 93% while its equivalent availability averaged 71%. Mr. Schlissel concluded there are a number of factors that suggest that Edwardsport's operating performance, especially on syngas, should not be expected to improve significantly in the foreseeable future: 1. The plant continues to generate significantly less than its design 618 net MW of power in every hour of the year and far less than 595 MW in almost all hours, as well. 2. The plant continues to lose a significant portion of its potential generation due to gasifier equipment problems, leading to its poor operating performance, particularly on syngas during its first 77 months of operations. 3. Edwardsport's gasification systems continue to operate inconsistently and unreliably. 4. The plant continues to have extremely high parasitic loads and high equivalent forced outage rates. 5. The plant continues to have extremely high heat rates.

Mr. Schlissel went on to review natural gas market prices, indicating there has been a long period of low gas prices, which he expects to continue. Further, there has been a revolution in the development of renewable resources as declining prices and technological improvements have led to dramatic growth in the MW of installed wind and solar capacity and the MWh of generation from these resources. As a result, energy market prices have declined and generation from many coal-fired generators has been displaced. Additionally, Mr. Schlissel indicated that given Edwardsport's very high operating costs, there would undoubtedly be incremental end-use efficiency resources available at a lower cost. These incremental resources should be considered when evaluating whether the Company should continue to operate or retire Edwardsport. Finally, Mr. Schlissel concluded the Commission should consider the plant's carbon dioxide emissions when considering the future operation of the plant.

Mr. Schlissel concluded that the following options should be considered by the Commission: 1. Continued operation of Edwardsport as an IGCC with a cap on its operating expenses for ratemaking purposes; 2. "Mothballing" Edwardsport's coal gasification processes and equipment for the foreseeable future while continuing to operate the plant at reduced capacity on natural gas; and 3. Retiring Edwardsport in the near future and replacing its generation with renewable generation and end-use efficiency.

(VI) Commission Discussion and Findings. The estimated life of generating units does significantly impact the depreciation rates in this proceeding. Duke Energy Indiana's proposed depreciation rates use the retirements dates from what the Company refers to as a ~~the~~ "moderate transition portfolio," which was its resulting preferred portfolio coming out of the IRP stakeholder process. Sierra Club and Joint Intervenors took issue with the retirement dates of Edwardsport IGCC and other coal units, finding that Duke Energy Indiana should consider retirement of these units sooner. Taking Edwardsport first, we agree that the evidence supports an investigation into the potential retirement of Edwardsport and its gasification infrastructure, an analysis which Duke entirely failed to do here or in its most recent IRP. Multiple sets of evidence support Joint Intervenor and Sierra Club's contention that continued operation of Edwardsport is likely not in the best interest of ratepayers.

First, Duke testified that it self-schedules Edwardsport as must-run on coal whenever a gasifier is available. *See* Petitioner's Ex. 51, p. 22, lines 7–9; Tr. K-11, lines 10–18. The limited number of Profit & Loss Statements that the Company was willing to produce in discovery demonstrate that Duke self-schedules Edwardsport as must-run on coal even when the units are projected to lose a significant amount of money, and even when the Company projects that the plant would turn a profit operating on gas. JI CX 32-C, JI CX 34-C. These sustained market losses add up: Mr. Comings found that the self-commitment of Edwardsport as must-run led to market losses of $93 million from 2016 through 2018. Sierra Club Ex. 1, p. 4, lines 12-14 (loss totals based on variable costs alone, excluding fixed costs).

In addition to its losses related to uneconomic self-commitment, a host of other factors call into question whether Edwardsport's continued operation as an IGCC plant is in the economic interest of Duke's ratepayers. These include:

- Edwardsport's consistent failure to achieve its 618 MW net full capacity rating;
- Edwardsport's poor and unreliable operating performance, especially that of its gasification system;
- the plant's extremely high parasitic loads;
- the plant's extremely high heat rate;
- that the plant's production costs would remain extremely high even if capped;

- the Company's projected high levels of additional capital investments that would be incurred if Edwardsport continues to operate;

- continued low natural gas prices;

- continued competition from available, low cost end-use efficiency; and

- increasing competition from renewable resources due to declining wind and solar power purchase agreement ("PPA") prices, especially but not exclusively when combined with storage strategically sited and sized. JI Ex. 6, p. 3, lines 10-29; *see also id.* pp. 4–30.

Taken together, these factors show that Edwardsport is both failing to meet operational expectations and is not able to compete with the other types of generation resources that are presently producing lower cost electricity on the MISO market (and potential candidates for future replacement of Edwardsport's generation capacity).

In rebuttal to the concerns raised by Joint Intervenors and Sierra Club about Duke committing Edwardsport as must-run, the Company revealed that Edwardsport is an incredibly inflexible generation resource. In particular, Duke contends that must-running the unit on coal is necessary because of the long cycle time for the gasifiers, the adverse reliability and efficiency impacts of turning the gasifiers off, and operational difficulties and costs related to switching fuels at the plant. These claimed technical and engineering reasons for near constant self-scheduling of Edwardsport as must-run on coal bear further investigation and verification. If true, however, the reasons that Duke offers in defense of its self-scheduling Edwardsport as must-run indicate that Edwardsport's operators lack any ability to respond to even the strongest of market signals and to manage operation of the plant in the economic interests of its ratepayers.

Duke also attempts to justify self-scheduling Edwardsport as must-run on the basis of the potential for coal oversupply in the event that Edwardsport were decommitted or switched to running on gas. Duke witness Gurganus testified:

> Edwardsport receives coal under contract from a local mine. My understanding is that if Edwardsport were to switch to natural gas for any significant length of time, the Duke Energy Indiana system would be oversupplied with coal, potentially requiring the reinstitution of the decrement process. It certainly seems non-sensical to burn natural gas, only to end up having to decrement the coal units' costs so they will burn more coal.

Petitioner's Ex. 49, p. 9, lines 10–15. This is not a true technical constraint that prevents Edwardsport from being committed economically. Instead, as we found in Section 7.e above, ~~Rather~~ it is an indicator that Duke has practiced imprudent fuel procurement practices. Such imprudent practice cannot, of course, be used to justify uneconomic operation of Edwardsport.

Duke also argues that keeping Edwardsport, and specifically its gasifiers, around provides "long-term diversity benefits" in regards to fuel choice, as it will allow the utility to continue to burn coal into the year 2045. Petitioner's Ex. 49, p. 14, lines 6–9; see also, id. p. 12, line 8–p. 13, line 21. But maintaining long-term flexibility to burn coal comes at a high cost: it apparently requires Edwardsport to primarily burn the far more expensive of the two fuels (coal) today, while gas prices are certainly far lower, to offset a risk that gas prices might eventually exceed coal prices someday. Forcing Duke's ratepayers to continue to pay the elevated costs of Edwardsport's commitment today—which is uneconomic as compared to both running the unit on gas and simply decommitting it and purchasing an equivalent amount of energy from MISO—in order to preserve the opportunity to burn coal should it re-emerge as an economically competitive fuel source in the long term is not reasonable. And it is not an economic tradeoff that the Commission can reasonably allow Duke to require its ratepayers to continue to make.

In short, the record related to these inherent weaknesses of Edwardsport provide strong evidence that retirement of Edwardsport, or at least the gasifiers, would be the most reasonable and prudent outcome for Duke's ratepayers.

Thus, pursuant to Indiana Code § 8-1-2-51, we order a formal investigation into the future of Edwardsport and are hereby opening a subdocket investigation. In the meantime, Duke's IGCC-17 rates for Edwardsport collected through Rider 71 shall continue, subject to refund or additur, pending the outcome of a subdocket related solely to the future of Edwardsport. ~~we find that Mr. Gurganus' testimony persuasive. Edwardsport is the newest coal unit on the system and continues to be a valuable asset for the Company's diverse generating system, especially as the Company moves, as many utilities are, to retire older and less efficient coal plants. We also understand the many complexities and issues associated with primarily operating the plant on natural gas pointed out by Mr. Gurganus, not least of which is the requirement for new air permitting, elimination of tax incentives, and losing the optionality and diversity that operation primarily on coal provides. In contrast to cross answer testimony of Mr. Schlissel, based on the testimony provided by Mr. Gurganus, we find that Edwardsport has showed steadily increasing gasifier availability and capacity factor in line with expectations, and we note that the Company has invested in improvements at the plant, often at shareholder expense, to achieve these improvements, which Mr. Gurganus expects to continue.~~

As to the Company's other coal units, Sierra Club and Joint Intervenors criticize the Company's modeling that does not allow these units to retire prior to 2024. In fact, Duke does not propose to retire any of its coal units until 2026. We agree with these criticisms. The Company missed the opportunity to objectively evaluate the potential accelerated retirement of any of its units, raising a concern about the Company's ability to maintain maximum and reasonable optionality in the short-term. The Company should have more thoroughly reviewed unrestricted retirement of all coal-fired units, including Edwardsport, in the IRP. While retirement of Edwardsport will be evaluated in the subdocket that we ordered to be open above, we expect that the Company will provide a thorough and objective evaluation of the most economic retirement dates for its Cayuga and Gibson units in its next IRP. ~~However, we find Mr. Pike's testimony on this point persuasive. There are clearly practical constraints and considerations to retiring units that should not be ignored by IRP modeling, such as labor force, community impacts, transmission constraints, and not least of all rate impact to customers. Further, we note that if it were a meaningful constraint, we would expect mass retirements to appear in 2024 in the optimized portfolio results, which did not occur. We also agree with Mr. Pike and Wabash Valley witnesses that it is reasonable to swap the retirement dates of Gibson Units 4 and 5, to accommodate the wishes of the joint owners of Gibson 5 and save the expense associated with the planned flue gas work for the units. Overall, we find that the Duke Energy Indiana 2018 IRP preferred portfolio, as modified with the Gibson Unit 4-5 retirement date swap, misses an opportunity to seriously weigh the risks in its fleet and to maintain maximum flexibility. We agree with Joint Intervenors~~

~~that the IRP stakeholder process was not as effective or transparent as could have been the case, and thus we are concerned about relying on such for the basis of this decision. Therefore, spreads out the coal unit retirements in a prudent and reasonable and cost effective manner. We find that this moderate transition approach is reasonable and results in reasonable depreciation rates in this proceeding.~~

~~Regarding the other Joint Intervenors criticism of the IRP process, we find that the IRP is at issue in this proceeding only to the extent it helps support the proposed depreciation rates. Duke Energy Indiana has demonstrated that the stakeholder process was robust and that its moderate transition plan was a robust portfolio under a number of distinct future scenarios, in terms of rate impact, reliability, resiliency and risk. We find Mr. Park's response to the various IRP issues reasonable and thorough. Further, we agree with Mr. Pike that models only inform us and do not make reasoned recommendations or decisions. Rather, the Company does that through a review of various scenarios, sensitivities and portfolios.~~

~~In sum, we find that Duke Energy Indiana's proposed depreciation rates in the proceeding, as revised in its rebuttal testimony for the Gibson 4/5 retirement date switch, are reasonable, prudent and will result in fair and reasonable rates for customers who benefit from the Company's rate base.~~

iii. O&M Expenses (Other than Depreciation and Taxes).

(A) Production O&M Expense.

(I) Petitioner's Evidence. Petitioner's witness Mosley testified that Duke Energy Indiana's 2020 power production O&M forecast is $407 million, as follows:

Category	O&M ($ in millions)
Edwardsport IGCC	$139
Coal Combustion Products	$12
New Generation Resources	$0
Power Production	$229
Other Miscellaneous Power Production	$27
Total	**$407**

Mr. Mosley then testified in support of $229 million of the 2020 power production O&M for generating facilities other than Edwardsport. Mr. Mosley stated that power production O&M expense generally includes the cost associated with the operation, maintenance, administration and support of Duke Energy Indiana's generating units. Mr. Mosley provided the following table showing the components of the Company's proposed power production O&M for generating facilities other than Edwardsport for the 2020 test period, in addition to showing comparisons to 2018 actual and 2019 budget:

$ in Millions	2018 Actual	2019 Budget	2020 Forecast
Non-Outage O&M	$198	$182	$197
Increase / (Decrease)		($16)	$15
Outage O&M	$11	$27	$32
Increase / (Decrease)		$16	$5
Power Production O&M Total	$209	$209	$229

Mr. Mosley explained that non-outage O&M expenses are generally incurred on an ongoing basis, while outage-related O&M expenses generally are incurred only periodically based the maintenance cycle of the units. Mr. Mosley testified that each of the Company's generating stations has cyclical maintenance, which the Company attempts to schedule during off-peak times of the year with outages staggered to prevent the majority of units from being out for scheduled maintenance at the same time.

Petitioner's witness Gurganus supported the Company's proposed 2020 power production O&M expense of $139 million for the Edwardsport plant. As with Petitioner's other plants, Mr. Gurganus testified that the components of Edwardsport's O&M costs are: (i) basic generating station operations; and (ii) maintenance outages. Planned outage O&M expenses generally are incurred based on the maintenance outage cycle of the Edwardsport plant components. Mr. Gurganus testified that Duke Energy Indiana's 2020 Edwardsport O&M test period forecast includes $46.4 million in expenses associated with a major outage that occurs about once every seven years. He provided the following table showing the components of the Company's proposed power production O&M for Edwardsport for the 2020 test period, in addition to showing comparisons to 2018 actual and 2019 budget:

$ in Millions	2018 Actual	2019 Budget	2020 Forecast
Edwardsport O&M	$99	$96	$139
Increase / (Decrease)		($3)	$43
Less 2020 Major outage O&M			$46
Adjusted Increase / (Decrease)			($3)

Petitioner's witness Thiemann testified in support of the Company's proposed 2020 power production O&M expense of $12 million for coal combustion products. He explained these expenses were for the hauling of production ash to onsite landfills.

Petitioner's witness Landy testified that in Cause No. 44734, Duke Energy Indiana was granted a CPCN for the construction of a 17.25MW AC solar generation plant located at the NSA Crane base near Bloomington, Indiana. Mr. Landy stated that the Crane solar facility is commercially operational and provides clean, carbon free generation to the benefit of Duke Energy

Indiana customers. Mr. Landy stated that the Crane Microgrid Feasibility Study was completed to develop a project plan to support additional energy infrastructure at NSA Crane.

(II) OUCC's Evidence. OUCC witness Alvarez disagreed with the Company's proposal to include $229 million of power production O&M expenditures in the 2020 Test Year for generating facilities other than Edwardsport. Mr. Alvarez recommended using a seven-year average methodology to normalize O&M expenses, including the associated major outage costs, which he stated resulted in an $80 million reduction to Petitioner's proposed O&M costs. Mr. Alvarez stated that his proposal reduced the Company's generating facilities' forecasted Test Year O&M expenses to $149 million.

Mr. Alvarez explained that Duke Energy's proposed power production O&M cost for generating facilities other than Edwardsport includes $197 million of non-outage expense and $32 million of outage-related O&M expenses. Mr. Alvarez stated that the Company greatly overstated the $32 million annual outage-related O&M expenses requested. Mr. Alvarez stated that $32 million does not represent the typical year of power production and operation with cyclic major maintenance outages. Mr. Alvarez noted that since Duke Energy performed, or plans to perform, major outage work on all nine units in 2018-2020, there should be no scheduled major outages for 2021, 2022, 2023, and 2024 (based on a normal seven year cycle).

Mr. Alvarez recommended that Petitioner embed $149 million power production O&M expenses in base rates. Mr. Alvarez's proposal reflects a reduction in Duke Energy's proposed annual non-outage O&M expenses from $197 million to $129 million and a reduction in the Company's proposed annual outage-related O&M expenses from $32 million to $20 million.

Mr. Alvarez further recommended that the Commission require the Company to adopt a seven-year average methodology to normalize Edwardsport's overall O&M expenditures, major outage expenses, and miscellaneous administrative and general benefits costs. Mr. Alvarez recommended a decrease to the forecasted 2020 Test Year to an overall total of $61.87 million. Mr. Alvarez noted that this is an approximate $50.83 million reduction to the Company's proposal. Mr. Alvarez stated that the Company's recovery of Edwardsport's O&M expenses during the period 2016 through 2018 and projected in 2019 were subject to O&M caps under the provisions of the Settlements in prior proceedings related to the Edwardsport plant. Mr. Alvarez stated that in each year an O&M cap was in place, Edwardsport operations consistently exceeded the cap. Mr. Alvarez stated that Edwardsport operations have not achieved any significant expense reductions. Mr. Alvarez recommended that Duke Energy use an average of the forecasted Test Year 2020, and the forward-looking years through 2027 to determine Edwardsport O&M expenses.

(III) Industrial Group's Evidence. Industrial Group witness Gorman testified that operating Edwardsport on natural gas would allow it to produce electricity at a much lower cost than continuing to operate it as an IGCC. Mr. Gorman testified that if Edwardsport's dispatch costs are lower on natural gas, then all the fixed O&M costs associated with coal handling and operation of the coal to gas conversion facility can be avoided by shutting these facilities down or placing them in cold storage for use at a later time. Mr. Gorman stated that based on a comparison of Edwardsport to other similar vintage combined-cycle gas units ("CCGU"), it looks promising that Duke could avoid significant annual fixed O&M expense if it operated as a natural gas facility. Mr. Gorman testified that the workforce required to run

Edwardsport is much larger than what is required to run a comparable-sized natural gas facility. Mr. Gorman estimated that Edwardsport's O&M on natural gas for the forecasted test period is $20.4 million. Mr. Gorman concluded that using natural gas would result in a savings of $81.6 million over Duke's forecasted Edwardsport O&M costs in 2020 of $102.0 million.

Mr. Gorman concluded that costs that can be avoided by operating Edwardsport as a natural gas facility should not be included in rates in this proceeding. Therefore, Mr. Gorman recommended the Commission remove fixed costs needed for the operation of the coal gasification and coal handling facilities.

(IV) **Sierra Club's Evidence**. Sierra Club witness Comings recommended that Edwardsport costs should be denied and the Company should develop a plan for retiring the plant. Mr. Comings estimated that on a variable basis alone (*i.e.*, excluding fixed costs) the plant has cost ratepayers $93 million from 2016 through 2018. Mr. Comings stated that these losses are caused by: (i) Duke Energy operating most of the plant as "must run" instead of MISO economic dispatch; and (ii) Duke Energy bidding in the plant below its variable costs. Mr. Comings stated that put another way, if the plant had not operated from 2016 through 2018, ratepayers would have saved $93 million in energy costs.

Accordingly, Mr. Comings recommended the Commission deny the Company's request for Test Year capital, fuel, and O&M for Edwardsport because the Company cannot meet its burden to show that those costs are prudently incurred. Mr. Comings stated that the Commission should not allow the Company to charge ratepayers substantial fixed costs for a plant that is nearly always uneconomic to operate on a variable basis and would save ratepayers money if replaced. Mr. Comings stated that once the Company develops a plan for the plant's retirement, Duke Energy should be permitted recovery of fixed costs that have been adjusted to plan for imminent retirement. Mr. Comings testified that at the very least, the Company should be disallowed the $93 million in losses associated with the plant from the past three years because ratepayers were overcharged this amount for energy.

(V) **Petitioner's Rebuttal Evidence**. Petitioner's witness Mosley testified that OUCC witness Alvarez misinterpreted his direct testimony related to frequency and O&M costs associated with 2018 through 2020 planned outages for units other than Edwardsport. Mr. Mosley stated outages for these units are scheduled on an ongoing annual basis to help balance resource needs, cost, and optimized reliability. Mr. Mosley stated that the 2018 through 2019 outage expenses were lower than typical due to fewer maintenance outages being performed than normal. Mr. Mosley stated that the Company's $32 million request for 2020 is more representative of a typical year, and consistent with future year-to-year forecasts.

Petitioner's witness Pike testified that there were problems with Mr. Alvarez's seven-year average methodology to normalize O&M expenses based on Petitioner's IRP. Mr. Pike stated that Mr. Alvarez only included the fixed component of O&M cost as modeled in the IRP in his analysis – not variable costs. Mr. Pike testified that omission of the variable O&M component excludes significant real costs from the OUCC's analysis, including emission control reagents, coal and waste handling, and other outage and non-outage variable maintenance expenses as so-modeled. Mr. Pike testified that including variable costs results in a 2020-2024 average of the total O&M cost as-modeled in the IRP is $258 million, which is actually much higher than the $229 million proposed by the Company. Mr. Pike noted that removing property taxes and insurance costs results in an apples-to-apples comparison of $243 million, which is nearer yet still higher than the Company's request. Mr. Pike stated that de-escalating the future costs into constant year 2020 dollars, results in a 2020 to 2024 average of $232 million.

Mr. Pike stated that Mr. Alvarez's analysis and recommendations regarding Edwardsport's costs also is fundamentally flawed. Mr. Pike stated that including the Edwardsport variable O&M rate as well as a deduction for the 2020 planned outage cost, result in a nominal average of about $83 million, which compares to the Company's non-outage request of about $99 million from Mr. Gurganus' direct testimony. Mr. Pike testified that using as-modeled long-run O&M costs from an IRP is not an appropriate substitute for rigorously developed budgets at the functional level.

Petitioner's witness Gurganus testified that Duke Energy Indiana has been operating Edwardsport since before June 2013. Mr. Gurganus testified that the Company has improved plant performance every year through preventative maintenance and efficiently responding to emergent items. Mr. Gurganus stated that shutting the station down or even just shutting down or "mothballing" the gasification island, as the Industrial Group suggests, would both result in under-utilization of a significant investment. In Mr. Gurganus' opinion, making such a decision now is not the best course of action for Duke Energy Indiana and its customers. Mr. Gurganus stated that as the Company moves to retire its older coal-fired units, there is value in maintaining its youngest coal-fired unit, so that coal can continue to be a meaningful contributor to diversity for customers' benefit for years to come.

Mr. Gurganus further stated it is operationally difficult, time consuming, and costly to switch fuels in response to short-term natural gas price signals. Mr. Gurganus noted that Edwardsport receives coal under contract from a local mine and if it were to switch to natural gas for any significant length of time, the Duke Energy Indiana system would be oversupplied with coal. In addition, Mr. Gurganus noted that shutting down the gasifiers would entail loss of a highly trained and qualified workforce.

Mr. Gurganus noted that Mr. Alvarez does not appear to object to the Company's major planned outage expenses for Edwardsport. Mr. Gurganus stated that Mr. Alvarez made critical errors in his analysis of the 2018 IRP as modeled O&M costs for Edwardsport. Mr. Gurganus stated that the Commission should consider the Company's non-outage O&M expense request in this proceeding reasonable, necessary, and prudent for operation of the facility, and not color it with what was modeled in the IRP. Mr. Gurganus testified that he provided an opinion of potential ongoing O&M cost reductions to inform the IRP modeling, which resulted in the differences between the as-modeled IRP O&M costs ($82.8M per year average over twenty years) and the Company's request for the non-outage O&M expenses in this proceeding. Mr. Gurganus testified that he cannot guarantee the degree of savings that may be achieved and the Company's non-outage O&M expense request in this proceeding represents the currently known actual costs for Edwardsport.

(VI) **Commission Discussion and Findings**. The parties dispute Petitioner's power production O&M costs. The issues of contention are: (i) whether the Edwardsport plant should be shut down completely, run as a gas plant or continue to operate as an IGCC plant; (ii) the appropriate amount of O&M expenses for plants other than the Edwardsport station; and (iii) the appropriate amount of non-outage related O&M cost for the Edwardsport station. We examine each of these issues in turn below. We address Joint Intervenors' arguments for disallowance of past dispatch related costs for the past three years in the section on FAC issues later in this order.

(a) Continued Operation of the Edwardsport Plant. Consistent with Section 11(c)(ii)(C) above regarding the Commission Discussion and Findings related to Pro Forma Adjustments – Depreciation and the Estimated Useful Lives of Edwardsport, pursuant to Indiana Code § 8-1-2-51, we order a formal investigation into the future of Edwardsport and are hereby opening a subdocket investigation. In the meantime, Duke's IGCC-17 rates for Edwardsport collected through Rider 71 shall continue, subject to refund or additur, pending the outcome of a subdocket related solely to the future of Edwardsport. ~~The Sierra Club argues the entire Edwardsport station should be shut down immediately. The Industrial Group recommends the plant should be operated as a natural gas plant and that O&M costs associated with operating the plant as a coal plant should be disallowed. Duke Energy Indiana has been operating Edwardsport since approximately June 2013 (its in-service date), and Mr. Gurganus noted that a full maintenance cycle has yet to be completed. As noted above, we believe it is vastly premature and imprudent to make a decision to retire Edwardsport at this point in time. As Mr. Gurganus noted, the Edwardsport plant will provide diversity in the future as the Company moves to retire its older coal-fired units. We believe that, as Duke Energy Indiana and other Indiana utilities continue to retire thousands of megawatts of coal-fired baseload generation, the remaining baseload units -- such as Edwardsport -- will become more important from a grid reliability perspective. The Edwardsport IGCC is the Company's youngest and most advanced coal-fired unit. The plant has advanced emission controls that will allow coal to continue to be a meaningful contributor to diversity for customers' benefit for years to come.~~

~~We have consistently recognized the importance of generation resource diversity. For instance, in *Indiana & Michigan Power Company*, Cause No. 44511 (IURC; February 4, 2015), we noted that "Chapter 8.5 reflects an integrated resource process which seeks to utilize a diversified portfolio of supply side and demand resources (e.g., coal, gas, nuclear, wind, solar, energy efficiency, load management)." We have, in fact, emphasized the importance of fuel diversity in multiple proceedings. *See e.g., Verified Petition of Indianapolis Power & Light Company for Certificates of Public Convenience and Necessity*, Cause No. 44794 (IURC; April 26, 2017)("fleet fuel diversity mitigates risks'); *Joint Petition of PSI Energy, Inc. and CinCap VII for Issuance of Certificates of Public Convenience and Necessity*, Cause No. 42145 (IURC; Dec. 19, 2002)(the addition of gas-fired peaking capacity will benefit the system in terms of fuel diversity and mitigating future environmental regulation risk); *Wabash Valley Power Association for Issuance of* a *Certificate of Public Convenience and Necessity*, Cause No. 42321 (IURC; March 26, 2003) ("Landfill Units are an appropriate choice to meet Petitioner's need for additional generating capacity, which should enhance system integrity and reliability and provide Petitioner with increased fuel diversity.").~~

~~We also reject the Industrial Group's proposal to effectively convert the plant to a gas plant while the price of gas is low. The evidence indicates that such a conversion decision would have permanent repercussions, and would put the future use of the plant as a dual-fueled syngas/natural gas plant at risk. As noted above, we find persuasive Mr. Gurganus' testimony that it would be operationally difficult, time consuming, and costly to switch fuels in response to short-term natural~~

~~gas price signals in an attempt to capture benefits for customers. Among other things, the Company would lose the highly trained and qualified workforce, which Mr. Gurganus stated would be devastating to the future of restarting the plant on coal. Mr. Gurganus also noted that Edwardsport receives coal under contract from a local mine and the Company would be oversupplied with coal if it were to switch to natural gas for any length of time.~~

(b) **Non-Edwardsport O&M Cost**. The OUCC recommended using a seven-year average methodology to normalize O&M expenses for plants other than the Edwardsport station, resulting in a proposed $80 million reduction in O&M costs. Duke Energy witness Pike, however, testified that the OUCC's seven-year average analysis only included the fixed component of O&M cost in the derivation of the $80 million adjustment. In excluding variable O&M costs, the OUCC inadvertently omitted significant costs, including: emission control reagents, coal and waste handling, and other outage and non-outage variable maintenance expenses. Mr. Pike further testified that the OUCC's analysis also was in constant year 2017 dollars and thus did not include any inflation of costs to the appropriate year nominal dollars. Duke Energy witness Pike noted that if these issues were corrected, the resulting 2020-2024 average of the total O&M cost as-modeled in the IRP would be $258 million, which is higher than the $229 million proposed by Petitioner.

The OUCC's analysis also was based on a misunderstanding of Petitioner's maintenance schedule. Mr. Mosley testified that Duke Energy Indiana operates a fleet of forty-two units, with outages scheduled on an ongoing annual basis to help balance resource needs, cost, and optimized reliability. Mr. Mosley indicated that the Company's $32 million request for outage maintenance costs is representative of a typical year, and consistent with the Company's future year-to-year forecasts.

The evidence of record reflects that Petitioner's proposed O&M expense of $229 million is reflective of its ongoing needs for O&M expense for its generation units. "The theory underlying the use of any test year and of any adjustment method in the ratemaking process demands that the data used provide an accurate picture of the utility's operations during the period in which the proposed rates will be in effect." *See, e.g.*, *City of Evansville v. Southern Indiana Gas & Electric Co.*, 167 Ind. App. 472, 339 N.E.2d 562, 575. Because the evidence reflects that $229 million is an accurate reflection of the O&M needs of the Company's production facilities, aside from Edwardsport, we reject the OUCC's recommended adjustment.

(c) **Edwardsport O&M Cost**. The OUCC proposed $6.63 million per year, levelized, for major planned outage expenses at the Edwardsport Station, and $55.24 million per year for the balance of non-outage O&M expenses. The OUCC's $6.63 million per year is equivalent to the Company's requested $46.4 million amount for major planned outage expenses levelized over seven years ($46.4 million/7 years = $6.63 million/year). However, the OUCC's proposed non-outage O&M expense for the Edwardsport facility is significantly less than Petitioner's proposal.

Again, however, in determining the non-outage O&M costs for the Edwardsport plant the OUCC excluded the same variable O&M costs that it omitted with respect to Petitioner's other plants and neglected to factor in inflation. Accordingly, we find that the evidence reflects that

Petitioner's proposed non-outage O&M cost of $99.4 million is more reflective of Petitioner's ongoing needs than the OUCC's proposal.

Petitioner acknowledges that the ongoing O&M cost in the IRP modeling resulted in the differences between the as-modeled IRP O&M costs ($82.8 million per year average over twenty years) and the Company's request for non-outage O&M expenses in this proceeding ($99.4 million). However, Petitioner's proposal in this proceeding is more in line with its past experience. Petitioner's witness Gurganus indicated that he could not guarantee the savings set forth in the IRP. Accordingly, any reduction to Petitioner's proposed O&M expense based simply on goals set forth in its IRP is not "fixed, known, and measurable" – as such a reduction is not "known to occur."

We also decline Industrial Group's recommendation that only O&M costs associated with hypothetically running Edwardsport as a gas unit should be included in rates. We have found continued operations primarily on coal is reasonable for Edwardsport and as such, we are required to set a level of O&M in base rates based on such operation, which Duke Energy Indiana has adequately supported.

(B) Major Storm Damage Recovery Expenses.

(I) Petitioner's Evidence. Petitioner's witness Hart testified that the Company's actual major storm costs for 2018 were $21.4 million as compared to the 2020 forecast for major storm expense of $10 million. Ms. Hart provided a table showing that the average amount spent on major storm expenses over the last five years (2014-2018) was $12.7 million. Ms. Hart explained that a storm is classified as a Major Event Day ("MED") when a major reliability event causes a utility to shift into a crisis mode of operation in order to adequately respond. The Company will use MEDs to classify events as major storm events.

Petitioner's witness Sieferman testified that the Company proposed to embed $12.7 million in base rates for major storm expenses based on the five-year average. She indicated *pro forma* adjustments were made to increase O&M and payroll tax expenses in the 2020 forecasted test period to move from $10 million to the $12.7 million level. Ms. Sieferman stated that the Company would be defining major storms based on the MED classification described in Ms. Hart's testimony.

(II) OUCC's Evidence. OUCC witness Alvarez testified that there is no assurance that the utility incurred its historical major storm expenses from a prudent management of its storm expenses. Mr. Alvarez stated there is a need to create an incentive for the Company to manage its system and major storm expenses with prudence. To do this, he proposed that Petitioner be required to develop an operational plan to manage storm restoration activities that is coordinated with its vegetation management and TDSIC plans. Mr. Alvarez stated that such a plan would not throw off Petitioner's TDSIC schedule or burden its operational management of storm restorations.

Mr. Alvarez stated that if the Company agrees to develop an operational plan based on the goals prescribed, the OUCC does not oppose establishing a Major Storm Reserve in the amount of $6 million (see discussion on Major Storm Reserve later in the Order). Alternatively, Mr.

Alvarez testified that should the Commission deny the Company authority to establish a Major Storm Reserve mechanism, it should approve embedding $5 million in base rates to represent half of the Company's annual $10 million O&M budget for major storm expense (a reduction of $7.7 million from the Company's proposed normalized major storm expense amount).

(III) **Petitioner's Rebuttal Evidence**. Petitioner's witness Hart noted that Mr. Alvarez provided no evidence that the Company's storm response expense was imprudent. Ms. Hart testified that she has been involved with the Company's storm response efforts for seven years, and could attest that its efforts are robust, efficient, and proactive. Ms. Hart indicated that the Company uses an Incident Command System ("ICS"), which is utilized by other emergency response organizations such as FEMA, police, and fire departments. Ms. Hart stated that ICS is mandated by the Federal government for the public sector to be used during disasters. Ms. Hart testified that ICS allows for the integration of facilities, equipment, personnel, procedures, and communications operating within a common organizational structure. Ms. Hart stated that forcing the Company to merge major storm response, vegetation management, and TDSIC through a mandated operational plan would lead to inefficiencies, delays in restoration, and confusion.

Ms. Sieferman testified that the $12.7 million level proposed by Duke Energy Indiana is based on an average of actual historical costs, while Mr. Alvarez's recommendations appear to be arbitrary and not supported by any evidence. Ms. Sieferman stated that comparing the recommended level to both a three-year average of $16.6 million and a seven-year average of $11.1 million, illustrates that the $12.7 million level proposed is reasonable.

(IV) **Commission Discussion and Findings**. The issue we are faced with here is determining the appropriate amount to be built into the Company's base rates to fund the Major Storm Reserve. In making determinations regarding an appropriate level of operating expenses to be used in setting any component of a utility's rates, we are guided by the overall objective of achieving a level of expense that is representative of probable future experience. Indiana courts have emphasized the importance of viewing test year results and out of period adjustments in the context of estimating a representative ongoing level of utility expenses. *See, e.g.*, *City of Evansville v. Southern Indiana Gas & Electric Co.*, 167 Ind. App. 472, 339 N.E.2d 562, 575, in which the Court stated: "The theory underlying the use of any test year and of any adjustment method in the rate-making process demands that the data used provide an accurate picture of the utility's operations during the period in which the proposed rates will be in effect."

With the foregoing concept in mind, we note that Petitioner's proposal to embed $12.7 million in base rates for major storm expenses is based on a five-year average of the Company's actual major storm expense. The record shows that this five-year historical average of $12.7 million is representative of the Company's ongoing level of major storm restoration costs. Ms. Sieferman noted that the most recent three-year average of Petitioner's major storm restoration cost is $16.6 million, and the most recent seven-year average is $11.1 million. These averages illustrate that the $12.7 million level proposed by the Company is reasonably representative of probable future experience. On the other hand, Mr. Alvarez's alternative proposals of $5 million and $6 million are lower than the major storm restoration costs experienced in any of the last five years.

OUCC witness Alvarez justifies using a level of expense unsupported by the Company's past experience by arguing that "there is no assurance that the utility incurred its historical storm expenses from a prudent management of its storm expenses." (Public's Exh. 5 at 22.) Mr. Alvarez's argument misconstrues a utility's burden of proof in a rate proceeding. Petitioner was not required to provide evidence in its case-in-chief that each expense incurred during the test period (or prior periods) was prudently incurred. To the contrary, in *Re Indiana Michigan Power Company*, Cause No. 39314 (approved Nov. 12, 1993) at 5, this Commission held: "[i]n the absence of a showing of inefficiency or improvidence, either by direct or circumstantial evidence, actual historic or specifically identified future expenditures by a utility cannot be merely disregarded for ratemaking purposes." We explained:

> In sum, while I&M has a burden of proof to present evidence of its ordinary and necessary level of business expenses, I&M is not required to overcome any presumption that its expenditures are "unnecessary and wasteful" until proven otherwise, On the contrary, at least a rebuttable presumption exists that such expenditures are legitimate. *West Ohio Gas Co. v. Public Utilities Commission of Ohio* (No. 1) (1934), 294 U.S. 63, 72; see also *Southwestern Bell Telephone Co. v. Public Service Commission of Missouri* (1923), 262 U.S. 276, 288, 289.

Id. at 5.

In this case, there is no evidence of "inefficiency or improvidence." To the contrary, Petitioner's witness Hart provided substantial evidence that Petitioner's major storm restoration expense has been prudently incurred. Ms. Hart noted that every employee has responsibilities during major storm events. Moreover, the Company uses an ICS, which is utilized by other emergency response organizations such as FEMA, police, and fire departments. Ms. Hart further noted that the Company received recognition for its storm restoration activities in 2018 and 2019. Specifically, Ms. Hart testified that in both 2018 and 2019, Duke Energy was honored with the Emergency Recovery Award, which is given to recognize extraordinary efforts to restore power to customers following service disruptions caused by severe weather conditions or natural events. Based on the substantial evidence of record, we reject Mr. Alvarez's recommended major storm outage expense adjustment, as well as his recommended changes to the Company's procedures.

(C) Vegetation Management.

(I) Petitioner's Evidence. Petitioner's witness Christie testified that the Company is increasing routine distribution vegetation management work over the next three years to move to an average five-year tree trimming cycle with an expected ongoing O&M cost of $49.4 million annually. Mr. Christie believes $49.4 million is necessary to sustain a five-year maintenance trim cycle while maintaining safe and reliable service to customers. To support Petitioner's request, Mr. Christie stated that Duke Energy Indiana commissioned Environmental Consultants, Inc. ("ECI") to perform a regrowth analysis of tree-to-conductor contact by cycle length for the Duke Energy Indiana service territory, which found that a five-year trim cycle is appropriate for Duke Energy Indiana's distribution system.

Petitioner's witness Graft testified sponsored Schedule OM17 which shows an increase in Test Period operating expenses of $10,479,000 so that the amount of distribution vegetation management costs recovered through base rates reflects the expected ongoing annual level of $49.4 million.

Petitioner's witness Abbott testified that the Company's transmission vegetation management plan is designed to eliminate vegetation on right-of-way caused outages on circuits with voltages of 200 kV and above, in compliance with NERC Reliability Standard FAC-003. Mr. Abbott stated that the O&M for transmission vegetation management in 2018 was $5.62 million, the projected 2019 O&M is $7.65 million, and the projected 2020 O&M is $7.61 million.

(II) OUCC's Evidence. OUCC witness Hand did not oppose the test period O&M for transmission vegetation management of $7.6 million. However, the OUCC opposed the Company's proposed revenue requirement for vegetation management of its distribution system. Mr. Hand proposed a *pro forma* revenue requirement for routine vegetation management O&M of the distribution system be set at $32 million and that any amount not spent on such routine maintenance in a given year be returned ratepayers.

Mr. Hand stated that none of Duke Energy's witnesses explained with any degree of specificity why its forecasted test year vegetation management spend (O&M and capital) should be $90 million. Mr. Hand further stated that, Duke Energy's proposed vegetation management initiatives are not well defined or well supported. Moreover, Mr. Hand stated that there is no evidence the Company has ever achieved a five-year trim cycle or that it will be able to do so. Mr. Hand noted that the Company has not explained in its case what it would do over the next three years to achieve an average five-year trim cycle.

(III) Petitioner's Rebuttal Evidence. Petitioner's witness Christie stated that the Company is well positioned to meet a five-year trim cycle. Mr. Christie also disagreed with Mr. Hand's testimony asserting that the Company will not be able to achieve a five-year trim cycle. Mr. Christie stated that past performance and miles trimmed prior to substantial contractor cost increases demonstrated the Company's ability to prune over 3,000 miles on an annual basis in 2014 and 2015.

Mr. Christie stated that any expectation that the Company will spend the exact amount of vegetation management O&M included in its base rates each and every year fails to recognize the nature of vegetation management. Mr. Christie stated that vegetation management activities are highly sensitive to weather, both on a localized basis and on a regional basis. Accordingly, Mr. Christie testified that the Company disagreed with Mr. Hand's proposed credit of unspent funds.

Petitioner's witness Graft further addressed Mr. Hand's proposal to credit customers for the unspent portion, if any, of vegetation management O&M in base rates. Ms. Graft stated it is unreasonable and inappropriate to effectively track vegetation management O&M expenses that are lower than the amount in base rates in a given year without giving consideration to other transmission and distribution expenses that may have increased during that same time period. Ms. Graft stated that a more balanced and appropriate alternative to Mr. Hand's proposal would be to utilize a cumulative reserve accounting approach under which the Company would record a regulatory liability for the amount by which its cumulative vegetation management O&M for the time period between base rate cases is less than the amount being recovered through base rates.

(IV) Commission Discussion and Findings. Petitioner's proposal is to implement a proactive five-year trim cycle. In general, a more frequent trim cycle reduces the amount of outages caused by vegetation. Trees account for a significant percentage of unplanned outages and consistent vegetation management can mitigate their impact on the system and customers. Trimming and removal also facilitates more timely service restoration. Accordingly, we have previously approved trim cycles more frequent than Duke Energy's proposed five-year cycle. For instance, in I&M's last rate case, I&M "committed to achieving a four-year trim cycle." *Indiana Michigan Power Co.*, Cause No. 44967, 28 (IURC 5/30/2018).

In this case, Petitioner presented substantial evidence in support of its proposed five-year tree trimming cycle. The Company commissioned ECI to perform a regrowth analysis of tree-to-conductor contact by cycle length for the Duke Energy Indiana service territory. After the initial report, the Company requested a data validation to account for specific regrowth of species found in Duke Energy Indiana's service territory, which was completed on October 17, 2014. This study concluded: "The new data projections suggest that a five-year routine maintenance cycle (with a minimum 10-foot clearance specification at the time of pruning) is appropriate for the Duke Indiana distribution system when included as part of the overall IVM (integrated vegetation management) program." (Pet. Exh. 27-A at 21.)

Based on the foregoing evidence, we find the Company's proposal to move to a five-year tree trimming cycle is supported and in the public interest. The OUCC's main objection to Petitioner's proposal is its concern that Petitioner will be unable to move to a five-year cycle and thus will have unspent funds. However, the evidence reflects that before the labor shortage, Duke Energy Indiana was able to prune over 3,000 miles on an annual basis – which is consistent with its proposal to move to a five-year cycle.

Vegetation management is inherently impacted by weather. Accordingly, there may be years Duke Energy Indiana will not be able to trim the amount of miles it anticipates. However, there also will be years where Duke Energy Indiana may be able to trim more miles than anticipated. This is the nature of any number of expenses incurred in the operation of a utility. Accordingly, the Commission's objective in any rate case is to estimate "a representative ongoing level of utility expense." See *Re PSI Energy*, Cause No. 42359 (approved May 18, 2004), 2004 WL 1493966 (Ind. U.R.C.), 234 P.U.R.4th 1, 54.

We decline the OUCC's proposal to create a tracker to return to customers any unspent vegetation management funds. As noted by Ms. Graft, there are many reasons why a specific expenditure may not occur in one year, such as resource constraints due to major storms, and having such funds available for future years enables flexibility. However, we are persuaded by Duke Energy Indiana's rebuttal testimony, which indicated that a better mechanism to ensure vegetation management related revenues are spent on vegetation management related costs, is to utilize a cumulative reserve accounting approach under which the Company would record a regulatory liability for the amount by which its cumulative vegetation management O&M for the time period between base rate cases is less than the amount being recovered through base rates. To the extent the entire amount in base rates is not spent in a given year, the Company will have the unspent amount set aside in the reserve account for vegetation management O&M costs incurred in the following years. Any balance remaining in the reserve account would then be addressed in the Company's next retail base rate case. As such, we accept this more balanced accounting approach discussed by Duke Energy Indiana.

(D) Incentive Compensation.

(I) Petitioner's Evidence. Petitioner's witness Metzler testified the benefits and compensation opportunities provided to Duke Energy Indiana's employees are reasonable, customary, prudent and market-competitive. Her testimony illustrated Duke Energy Indiana's benefit programs and compensation opportunities, which she said are critical for attracting, engaging, retaining and directing the efforts of employees with the skills and experience necessary to efficiently and effectively provide electric services to customers. Ms. Metzler indicated Duke Energy Indiana's compensation, benefits and career development opportunities directly affect its ability to attract and retain qualified employees.

Ms. Metzler explained the Company's compensation philosophy. First, she said compensation should be market-based, meaning competitive to the external market of similar companies, allowing Duke Energy Indiana to remain attractive against competition and attract and retain qualified employees.

Second, Ms. Metzler indicated the Company's compensation package links compensation to performance to set high expectations for employees and reward results. Finally, she testified the Company's compensation policies and pay administration guidelines ensure employees are paid consistently and fairly.

Ms. Metzler explained the compensation package for executives consists of a combination of fixed and variable pay using base salary, short-term incentives and long-term incentives, which in the aggregate, are targeted to deliver total compensation that is competitive with the applicable peer group and consistent with performance. She said Duke Energy adopted this executive compensation strategy in order to attract, retain and motivate the executive talent required to deliver superior performance. She indicated this strategy emphasizes performance-based compensation that balances rewards for both short-term and long-term results and aligns the executives' interests with the long-term success of Duke Energy, including Duke Energy Indiana.

To achieve the objective of providing competitive pay, Ms. Metzler explained the components of the Company's Total Rewards compensation program, which include: (1) a fair market value for all jobs; (2) annual merit increases to recognize individual performance, (3) annual short-term cash incentive ("STI") awards that reward eligible employees with cash bonuses when pre-established goals are achieved; (4) long-term incentive ("LTI") opportunities to attract and retain high-performing leaders; and (5) recognition awards given when employees make significant contributions to business operations due to exceptional personal initiative, dedication, perseverance or a uniquely effective approach to work. According to Ms. Metzler, the goal of having a LTI component as part of certain employees' total compensation package is to attract and retain high-caliber leaders and align their interests with the long-term strategy of Duke Energy, including Duke Energy Indiana, through equity-based compensation.

Ms. Metzler noted Duke Energy has two LTI programs. One is the Executive Incentive Plan ("EIP"), which is reserved for members of the Executive Leadership Team ("ELT") and

Senior Management Committee to drive an ownership mindset and ensure accountability for making short- and long-term strategic decisions.

She said EIP participants must generally continue their employment with the Companies for a three-year period to earn a payout and the number of performance shares that participants ultimately earn is tied to Duke Energy's long-term performance. The other 30 percent of EIP participants' target LTI opportunity is awarded as Restricted Stock Units ("RSUs"). Vesting of RSUs is solely tied to the participants' continued employment through vesting dates over a three-year vesting period and is not dependent upon the performance of the Companies.

A different LTI program is available to other strategic leaders below the ELT level who are responsible for the most critical roles/responsibilities in each business group (population generally ranges between 2-3 percent of the total Duke Energy employee population). These employees participate in the RSU program and receive their LTI value in the form of RSUs that vest equally over three years, thereby encouraging retention of high-quality employees. The reward of these RSUs is purely aimed at continuing employment and is in no way tied to actual company performance. These employees' base salary is set at such a level, that, when factoring in the retention-driven RSUs, the total package results in a market-competitive package.

Ms. Metzler testified Duke Energy Indiana seeks to recover in rates the incentive pay expenses that are directly assigned or allocated to Duke Energy Indiana assuming goal achievement at the target level. That means for top executives, approximately 10% of their incentive pay would be allocated to Duke Energy Indiana in a typical year. She noted that all of the various performance measures included in the Companies' incentive plans were designed to benefit customers, which is why Duke Energy Indiana proposed to recover the entire amount of incentive compensation costs, allocated to Indiana, in its revenue requirement calculation.

(II) **<u>OUCC's Evidence</u>**. OUCC witness Kollen described Duke Energy Indiana's request for recovery of incentive compensation expense tied to financial performance metrics. He indicated the Company included $28.655 million in total incentive compensation expense, consisting of $12.401 million tied to achievement of financial performance metrics by Duke Energy, Inc. and DEBS, and $16.254 million tied to the achievement of other performance metrics.

In Mr. Kollen's opinion, incentive compensation expense tied to Duke Energy's financial performance should not be included in the Company's revenue requirement. He testified the fundamental ratemaking issue is not whether Duke Energy Indiana incurs incentive compensation expense tied to its parent company's financial performance, but whether Duke Energy Indiana's customers should reimburse the Company for this portion of incentive compensation through their rates. He indicated this determination depends on whether the incentive compensation expense ultimately is incurred to incentivize performance that benefits the Company's customers, not harms them, or whether it is incurred to incentivize performance that benefits Duke Energy's shareholders.

Mr. Kollen stated the achievement of Duke Energy Earnings Per Share ("EPS") and Total Shareholder Return ("TSR") financial performance metrics exclusively benefit Duke Energy shareholders and not Duke Energy Indiana customers. In Mr. Kollen's view, incentive compensation incurred to incentivize Duke Energy financial performance provides the Company's executives, managers, and employees a direct incentive to seek greater rate increases, in order to improve its parent company's EPS and TSR. He said incentive compensation expenses tied to financial performance metrics should be allocated to Duke Energy shareholders, not Duke Energy Indiana's customers.

As a result, Mr. Kollen recommended a $12.309 million reduction in the Company's revenue requirement for incentive compensation.

(III) Industrial Group's Evidence. IG witness Gorman testified Duke Energy Indiana included $24.8 million of incentive compensation in its revenue requirement. He acknowledged it is appropriate to include incentive compensation costs in the Company's ratemaking cost of service but noted incentive compensation programs designed to align the interests of executives with shareholders should be paid by shareholders. In Mr. Gorman's opinion, incentive compensation programs that reflect customer direct goals, such as service reliability, can be incurred by ratepayers, depending on whether the performance metrics are met.

Mr. Gorman observed that including incentive compensation related to financial goals in the cost of service exposes customers to the risk of paying incentive compensation costs, without assurance that the financial targets will be achieved or have any benefit to customers. He said this risk would not be faced by investors if the financial compensation rewards are excluded from cost of service because shareholders can pay for the costs out of higher earnings if the financial goals are achieved.

After reviewing the Commission's findings regarding the recovery of incentive compensation in Duke Energy Indiana's last rate case, Cause No. 42359, Mr. Gorman concluded the Company has not demonstrated in this case that shareholders are allocated part of the cost of the incentive compensation programs. Mr. Gorman then recommended removal of the portion of the cost of incentive compensation that relates to financial performance, which he determined to be $13.3 million. He stated the cost of incentive compensation designed to align the interests of employees with shareholders should be paid by shareholders and excluded from cost of service. He added that it is inappropriate to include in rates incentive compensation that is tied to financial performance and therefore may or may not be paid out.

(IV) Petitioner's Rebuttal Evidence. Duke Energy Indiana witness Metzler submitted rebuttal to the testimony of OUCC witness Kollen and IG witness Gorman both of whom stated the Company's incentive compensation expense should be adjusted to remove the portions of STI and LTI compensation tied to financial measures and achievement, as they believe these goals only benefit shareholders. Mr. Gorman also claimed the RSU component of the LTI plan should be removed as he contends it aligns the interest of employees with shareholders only.

Ms. Metzler testified the Commission should reject the proposed adjustments because they are based on a false premise and contrary to long held and well-established Commission determinations that incentive plan costs are recoverable in rates when: (1) the incentive compensation plan is not a pure profit-sharing plan, but rather incorporates operational as well as financial performance goals; (2) the incentive compensation plan does not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) customers and shareholders are allocated part of the cost of the incentive compensation programs. She indicated the Company satisfied each of the foregoing factors by proving that (a) the Company's incentive compensation plans are not pure profit sharing plans but include other metrics; (b) the Company's incentive compensation plans do not result in excessive pay levels beyond what is reasonably necessary for the Company to attract a talented workforce; and (c) the cost of the incentive plans are allocated to both customers and shareholders, as shareholders would cover any amounts above the target levels proposed to be included in the Company's rates.

With respect to Mr. Gorman's contentions regarding the proposed removal of the RSU component of the LTI Plan, Ms. Metzler stated it is factually incorrect to say that the magnitude of the expense for RSU payments is only aligned to shareholder interest simply because the award is in stock and not cash. She added these costs are a defined benefit amount that is primarily tied to the retention of high-performing employees and unlike all other incentives, the expense for RSU payments to eligible employees is unaffected by Company performance. She concluded her rebuttal on the RSU issue by noting the Company has a legitimate interest in attracting and retaining a high-performing leadership team which directly benefits customers through the accumulation of experience and knowledge.

Ms. Metzler recommended the Commission reject the OUCC's and Industrial Group's proposed adjustments to incentive compensation and permit Duke Energy Indiana to recover all incentive compensation expense in rates consistent with well-established criteria. She asserted the energy industry is a knowledge-intensive and experience-intensive industry where the tenure of employees matters, which means Duke Energy Indiana needs to attract, develop and retain—over the long term—the engineering professionals that design, help build and operate its plants at a reasonable cost. In Ms. Metzler's opinion, incenting a focus on financial performance via EPS and TSR provides a benefit to customers, as a financially strong Company will have greater access to capital at a lower cost, which in turn benefits customers through a lower cost structure. In addition, she observed the introduction of stock as a component of overall compensation ensures the Company's leadership is focused on the long term, and not overly focused on the short term.

(V) **<u>Commission Discussion and Findings</u>**. In Duke Energy Indiana's last general rate case (Cause No. 42359, Order dated May 18, 2004), we noted it is commonly accepted that incentive compensation plans may be necessary in order for utilities to attract and retain highly qualified individuals. Ms. Metzler provided evidence in her direct and rebuttal testimony to support this proposition. In that same Order, we also indicated our approval for the recovery of incentive compensation costs through rates where: (1) the incentive compensation plans are not pure profit-sharing plans, but rather incorporate operational as well as financial performance goals; (2) the incentive compensation plans do not result in excessive pay levels beyond what is reasonably necessary to attract a talented workforce; and (3) shareholders are allocated part of the cost of the incentive compensation programs. Order in Cause No. 42359 at 89.

OUCC witness Kollen and IG witness Gorman do not dispute the above-stated general proposition that incentive compensation plans may be necessary to attract and retain highly qualified employees. Nor do they dispute Duke Energy Indiana's evidence of record showing the Company's incentive compensation plans are not pure profit sharing plans or raise any issues with respect to the levels of Duke Energy Indiana's executive pay. Rather, the OUCC and IG contend that incentive compensation tied to Duke Energy's financial performance should not be included in the Company's revenue requirement because shareholders have not been allocated part of the cost of the incentive programs.

Based upon our review of Duke Energy Indiana's compensation programs and supporting evidence in this proceeding, we find that Duke Energy Indiana has satisfied the first two requirements for the recovery of incentive compensation in its cost of service. We further find from the evidence that shareholders are allocated part of the cost of the Company's incentive compensation in that the Company only proposed to include its target compensation amount in base rates, whereas the Company's incentive plans regularly pay-out at above target amounts. Accordingly, we find that Mr. Kollen's and Mr. Gorman's proposed adjustments to the level of the Company's incentive compensation should be rejected.

(E) Fee Free Payment Option.

(I) Petitioner's Evidence. Petitioner's witness Quick provided testimony regarding Duke Energy Indiana's proposal to offer a fee-free program option for residential customers who use credit cards, debit cards and electronic checks to pay their electric bills (the "fee-free payment option"). Ms. Quick explained that the Company currently offers residential customers the ability to pay by credit card, debit card or electronic check via the Company's website, mobile site, phone or IVR, and residential customers making payments by those means are subject to a $1.50 convenience fee, the entirety of which is paid directly to a third-party vendor, Speedpay. In order to offer the fee-free payment option, Ms. Quick explained the Company proposes to eliminate the convenience fees associated with these forms of customer payments and instead recover these costs as part of its cost of service.

Ms. Quick testified Duke Energy Indiana is proposing the fee-free payment option now because industry studies have demonstrated customers continue to move toward card transactions and away from checks, and that the number of payments made by credit and debit cards continue to grow as a preferred method of payment by many customers. Ms. Quick described that the current requirement to pay a transaction fee when making a payment by credit card, debit card or electronic check is one of the largest frustrations that customers experience, and customers have voiced such frustrations to the Company. Ms. Quick stated the fee-free payment option would lead to greater satisfaction for all customers who primarily pay for goods and services with a credit card, debit card, or electronic check.

Ms. Quick testified it would be reasonable for the Company to include the cost of the fee-free payment option in the cost of service that is paid by all residential customers, similar to how other payment options are handled. Ms. Quick stated the more convenient the Company can make the bill paying process for customers to pay bills, the more all customers will benefit and more customers will be satisfied. Ms. Quick pointed out that giving customers options to pay by the method of their choice without incurring additional fees will lead to more satisfied customers and, ultimately, customer savings.

Ms. Quick provided data regarding the 2020 forecasted cost of the fee-free payment program to Company witness Graft for use in calculating a *pro forma* adjustment of $4,528,000 to add to the cost of service. Ms. Quick explained that the forecasted amount included a reasonable projection of 34% growth of the use of credit and debit cards in the test period by residential customers. Ms. Quick testified that the growth projections were based on historical and current payment transaction data from 2016 through 2018, as well as benchmarking the growth projections against both industry data and a similarly-situated electric utility that offers fee-free credit card usage. Ms. Quick also stated her understanding that Indiana Michigan Power Company ("I&M") currently has a fee-free credit and debit card program.

(II) **OUCC's Evidence**. Lauren M. Aguilar testified on behalf of the OUCC with regard to the fee-free payment program. Ms. Aguilar noted that Duke Energy Indiana is unable to state with particularity the extent of customer savings related to the fee-free payment program. Ms. Aguilar took issue with Duke Energy Indiana's reference to the fee-free payment program approved by the Commission in Cause No. 44967, stating that the approval was part of a settlement agreement and should not be given precedential value.

Ms. Aguilar stated the OUCC's recommendation that Duke Energy Indiana's proposal to recover credit card fees through inclusion of $4,528,000 in base rates should be denied, because not all of the Company's residential customers should be required to pay for benefits used by a subset of customers. Ms. Aguilar noted that Duke Energy Indiana is free to offer the fee-free payment program, but the costs should not be permitted to be placed into base rates, and that any savings the Company has yet to quantify can cover the costs of the program.

(III) **Petitioner's Rebuttal Evidence**. Ms. Quick provided rebuttal testimony for the Company. She first explained the OUCC's position that residential customers should not be required to pay for benefits used by a subset of customers is not consistent with many other programs offered by utilities generally and Duke Energy Indiana specifically. Ms. Quick testified that the Company currently offers many programs that are used by a subset of customers, but which are paid for by customers generally and recovered in base rates. She stated the costs of billing and payment channels, such as the costs to produce and mail a paper bill, are spread across all residential customers.

Ms. Quick also addressed the OUCC's assertion that customer savings should cover the costs of the fee-free payment program, stating that the proposal conflates two issues. Ms. Quick reiterated that the proposed fee-free payment option is a means to increase customer satisfaction, not to create customer savings, and that it would be inappropriate to evaluate the success of the program on the amount of customer savings. Ms. Quick testified that there will be no direct cost savings associated with the program, as the fees to Speedpay will remain at the current $1.50 per transaction price. Rather, the program is meant to increase customer satisfaction, much like many other customer service programs offered by the Company, and the associated cost of service should be spread over all customers.

Finally, with regard to I&M's similar fee-free program, Ms. Quick acknowledged that the Commission's approval in Cause No. 44967 was in conjunction with a Settlement Agreement. However, Ms. Quick explained that the Settlement Agreement provided that any matters not addressed by the Settlement Agreement will be adopted as proposed by I&M in its direct and rebuttal case. Further, Ms. Quick explained that the extent of evidence provided by Duke Energy

Indiana in this proceeding was far more comprehensive than that put forward by I&M, and that the OUCC did not provide any testimony opposing I&M's proposal.

(IV) Commission Discussion and Findings. Duke Energy Indiana is proposing to offer the fee-free payment option, in order to eliminate the $1.50 convenience fee associated with customer payments by credit card, debit card, and electronic checks, and instead recover these costs as part of its cost of service. The Company proposes a *pro forma* adjustment of $4,528,000 to add to the cost of service. Duke Energy Indiana provided evidence to support its assertion that credit and debit cards continue to grow as a preferred method of payment by many customers, and that spreading these costs across its residential customer base as a cost of service is similar to how other billing and payment options are handled.

The OUCC expressed concern with spreading these costs across the residential customer base. However, we believe the costs associated with offering the fee-free payment option is a reasonable and prudent cost of providing service, similar to other payment channels offered by Duke Energy Indiana. Offering this program will also increase customer satisfaction, as it will allow customers the flexibility to make utility payments in accordance with their customer expectations, and consistent with trends of service providers generally and other utilities specifically. We conclude the fee-free payment option is reasonable and prudent, authorize the program's offering, and approve of the inclusion of the *pro forma* adjustment of $4,528,000.

iv. Tax Expenses.

(A) Federal and State Corporate Income Tax

(I) Petitioner's Evidence. Company witness Mr. Panizza testified that the Company's income tax calculations were made under the provisions of the Internal Revenue Code ("IRC") of 1986, as amended, including for the impacts of the TCJA, which reduced federal income taxes effective January 1, 2018, and the Indiana Administrative Code. He stated that the Company used the statutory federal corporate income tax rate of 21% for both the base period and forecasted period and that the Company used the composite statutory Indiana corporate income tax rate of 5.88% for current tax and 4.9% for deferred tax for the base period. He also explained that the Company used the composite statutory Indiana corporate income tax rate of 5.375% for current tax and 4.9% for deferred tax for the forecast period, 2020, explaining that the Indiana corporate tax rate is being reduced each year until it reaches 4.9% in 2022. Mr. Panizza also discussed the federal tax normalization rules, the Company's tax sharing agreement, the Company's investment tax credits, and explained the Company's calculation of forecasted property tax expense. He explained that the Company's current forecast reflects full usage of the credits associated with the Edwardsport ITC and the Company's renewable projects during tax years 2022 and 2023, but this will depend on the actual taxable income of the Consolidated Duke Corporation tax entity. He also discussed the TCJA Settlement provisions and how the Company complied with them.

Diana L. Douglas, Director Rates and Regulatory Planning for Duke Energy Indiana explained and supported several accounting, revenue requirements and ratemaking aspects of the Company's case, including the effective tax rate for the historical reference period and for the test period (Petitioner's Exhibit 4-H (DLD)). Ms. Douglas also supported the adjusted test period income tax expense calculation and *pro forma* adjustments that are attached as supporting schedules to Petitioner's Exhibit 4-H (DLD), which included:

- the federal and state current and deferred income tax impacts of other *pro forma* adjustments;
- the Company's synchronized interest deduction;
- the Company's parent interest deduction ("Muncie Remand deduction"); and,
- the removal of certain ITC and Excess Deferred Income Taxes ("EDIT") amortization credits which will not be included in the cost of service for base rates, but rather be included in the Company's Standard Contract Rider 67 – Tax and Merger Credits Adjustment ("Rider 67" or "Credits Rider").

Ms. Douglas sponsored Schedules TX1 and TX2 of Petitioner's Exhibit 4-H (DLD). Schedule TX1 summarizes the amounts of the forecast adjustments to remove non-utility current income taxes and the total *pro forma* adjustments made to Total Company Test Period federal and state income tax expense. In addition, she said Schedule TX1 shows the retail jurisdictional amounts at present rates, the taxes associated with the increase in pre-tax operating income due to the proposed revenue requirements increase, and the final Test Period income tax amounts at proposed rates. From the current and deferred federal and state income tax and ITC amount included in the 2020 forecast Mr. Jacobi provided, Ms. Douglas noted that $230,000 of non-utility tax was removed to get to the adjusted 2020 forecast.

Next she indicated the Company removed $12,718,000 in *pro forma* adjustments. Duke Energy Indiana witness Ms. Diaz used the resulting Total Company Test Period amount as the starting point for the jurisdictional separation study, and she provided the retail jurisdictional present rate amounts. Then the income tax amount associated with the proposed increase in revenue requirements was calculated for inclusion in the cost of service study by Ms. Diaz. The adjustment to income taxes for the proposed increase in revenue requirements was an increase of $99,206,000 in retail jurisdictional income tax expense.

Ms. Douglas testified Schedule TX2 shows the computation of current federal and state income tax expense at the Total Company level, as well as at the retail jurisdictional level for present and proposed rates. Column D shows the *pro forma* adjustments for each of the pre-tax book income items used in the current income tax calculation. Ms. Douglas indicated Schedule TX2 shows the computation of current federal and state income tax expense at the Total Company level, as well as at the retail jurisdictional level for present and proposed rates using the 21% statutory rate in computing federal current income tax expense and the 5.375% average annual statutory rate for Indiana for 2020 for computation of current state income tax expense.

Ms. Douglas explained the deduction for "parent interest" and the application of the Muncie Remand concept, which resulted in an additional interest expense deduction, for ratemaking purposes only, in calculating current federal and state income taxes due to the Company's participation in a Duke Energy Corporation Consolidated tax return. She stated this adjustment reduced test period income taxes by allocating a portion of Duke Energy Indiana's parent company's interest deduction to Duke Energy Indiana for purposes of computing income tax expense, thereby providing a tax benefit to customers. With respect to the income tax rates used to calculate deferred income taxes, she testified the Company used the 21% statutory rate in computing federal deferred income tax expense and 4.90% (the final statutory income tax rate under current Indiana law that will take effect July 1, 2021, after the currently scheduled annual tax rate reductions end).

(II) OUCC's Evidence. Witness Lane Kollen testified regarding several of the Company's tax issues. First, he described Duke Energy Indiana's use of the 4.90% income tax rate for the calculation of deferred income tax expense and said it was consistent with the Indiana income tax rate that will go into effect on July 1, 2021. Mr. Kollen indicated he disagreed with the Company's use of the 5.375% income tax rate for the calculation of current income tax expense and the gross revenue conversion factor.

Mr. Kollen testified the Commission could set base rates using an Indiana state income tax rate of 4.90% in this proceeding and in the gross revenue conversion factor, and then allow the Company to temporarily recover the differential as the income tax rate phases down through the Credits Rider (as an offset to the credits in the 1 rider) from the date new base rates go into effect in 2020 through June 30, 2021. He recommended this approach because the 5.375% Indiana state income tax rate is only temporary and the Company's base rates may be in effect for an extended period of time before they are again reset.

He noted this approach will allow a "permanent" reduction in the base revenue requirement and require only a "temporary" increase in rates through the Credits Rider. Mr. Kollen said the effect of his offset recommendation is a $2.026 million reduction in the retail base revenue requirement, which initially will be offset by an equivalent increase in the Credits Rider revenue requirement. He added that increase in the Credits Rider revenue requirement will phase out completely in July 2021, effectively implementing a $2.026 million rate reduction at that time.

Wes Blakley, Senior Utility Analyst in the OUCC's Electric Division testified regarding the OUCC's proposed alternative treatment for the Company's Excess Accumulated Deferred Federal Income Tax ("EADFIT") credit. He noted Duke Energy Indiana proposed to pass back the 2018 and 2019 protected EADFIT deferrals using ARAM, which is estimated to be over twenty years. Mr. Blakley stated there is no requirement that the 2018 and 2019 protected EADFIT amortizations be returned using ARAM. He said that without the TCJA Settlement Agreement, Duke Energy Indiana's customers would have been entitled to receive immediate refunds of the 2018 and 2019 protected EADFIT amortizations. He noted that instead, the TCJA Settlement Agreement states the amortization of Duke Energy Indiana's 2018 and 2019 protected EADFIT will be addressed in its next rate case. Considering the delay that has already occurred, Mr. Blakley argued it would be unreasonable to extend the refund of those monies to Duke Energy Indiana's customers over a period of more than twenty years. As a result, he testified the OUCC recommends the 2018 and 2019 protected EADFIT regulatory liability be passed back to customers over the life of the rates set in this Cause, which is three years. Subject to the final balance, Mr. Blakley stated using a three-year period results in a $10 million refund to customers.

Mr. Blakley also testified regarding Indiana State Excess Accumulated Deferred Income Taxes ("EADIT") and recommended the EADIT refund be passed back to Duke Energy Indiana ratepayers over eight years, which is the period of the current state corporate tax reduction. Since 2012, according to Mr. Blakley, the Indiana corporate income tax rate has been reduced almost every year - from 8.5% in 2012 to 5.25% in 2020.

Mr. Blakley added that even though the Company's actual state income tax expense was reduced during this period, because it has not filed a base rate case in over ten years, Duke Energy Indiana customers have continued to pay utility rates that reflect an outdated 8.5% corporate income tax rate since the May 18, 2004 Final Order in Cause No. 42539.

Mr. Blakley stated Duke Energy Indiana customers are owed a refund based on the difference between the Company's actual corporate income tax expense and the corporate income tax expense revenue requirement included in its base rates during the period between rate cases. Unlike federal excess deferred taxes, which result from a utility's election of accelerated tax depreciation, Mr. Blakley contended the Company's state corporate excess deferred taxes are not related to depreciation and, therefore, are not categorized as either protected or unprotected for purposes of IRS normalization rules. Mr. Blakley said the Company's total accumulated Indiana corporate EADIT as of December 31, 2020, including gross-up, is $38,074,638. Mr. Blakley recommended this amount be passed back to customers, through Duke Energy Indiana's Rider 67 Credits Rider, over the period of the current state corporate income tax reduction of eight years.

OUCC witness Kollen also addressed the amortization of the DEBS EADIT as a one-time credit in the credits Rider. He testified that DEBS should have refunded the EADIT to the Company and other regulated utility affiliate companies even if it had not charged them for income tax expense at the 35% federal income tax rate. He continued the Company recovers charges from DEBS in the same manner as if the Company had incurred the costs itself. DEBS acquired assets and depreciated those assets for book and income tax purposes. DEBS used bonus and MACRS accelerated depreciation for income tax purposes, which created temporary differences and the resulting ADIT for the bonus and accelerated tax depreciation in excess of straight line depreciation. DEBS charged the Company and other affiliate companies for the depreciation expense on these assets and is entitled to any tax benefits, including the EADIT. As a result of the foregoing assertions, Mr. Kollen recommended the DEBS EADIT be allocated to the Company in the same manner that DEBS depreciation expense is allocated to the Company and then refunded to the Company's customers as a one-time $2.910 million credit through the Credits Rider.

(III) **Industrial Group's Evidence.** IG witness Gorman provided testimony regarding Duke Energy Indiana's proposal for its Indiana EDIT. Mr. Gorman proposed (1) the Indiana EDIT be included in cost of service, (2) the $19.5 million balance for the pre-2011 rate changes be immediately netted against the $48.1 million credit for post-2011 rate to result in a net balance of $28.6 million; and (3) the amortization period be accelerated and the net balance be amortized over a period of three years, or $9.5 million per year. Mr. Gorman indicated that grossing up his EDIT adjustment for income taxes results in a revenue requirement impact of $12.7 million.

Like the Indiana EDIT, Mr. Gorman noted the 2018 and 2019 Federal EDIT amounts can be amortized in accordance with the Commission's discretion. He proposed that the $30.152 million 2018 and 2019 Federal EDIT be amortized over three years, or $10.1 million per year.

After grossing up that adjustment for income taxes, Mr. Gorman stated his Federal EDIT adjustment has a revenue requirement impact of $12.56 million.

The next tax topic Mr. Gorman covered was the Rider 67 allocation of TCJA credits. Mr. Gorman stated Duke Energy Indiana is using Rider 67 to pass back refunds to customers of protected and unprotected Federal EDIT that were approved in Cause No. 45032 S2 in the same manner in which the rates were collected from customers using a 12 coincident peak ("CP") allocation methodology.

Mr. Gorman indicated that when Duke Energy Indiana amended its case on September 9, 2019, it modified the allocation for revenues remaining in riders using the 4CP methodology, the impact of which change on the HLF class was a loss of $2.1 million in credits. As a result, and to avoid punishing the HLF class, Mr. Gorman recommended that Duke Energy Indiana should continue to allocate the TCJA credit using the 12CP allocation that was used when customers paid for the plant, equipment and property.

(IV) <u>Petitioner's Rebuttal Evidence</u>. Duke Energy Indiana witness Jeffrey R. Setser testified in rebuttal to OUCC witness Kollen's proposal to refund the EDIT to the Company and other affiliates. Mr. Setser stated the current income tax expense is a result of the return on DEB's assets for which the jurisdictions have a corresponding current deduction. He stated that deferred income tax assets or liabilities are considered temporary differences and have always been maintained at DEBS and any adjustments to deferred income taxes through the income statement should remain on DEBS. The depreciation for DEBS assets that is charged out to the utilities is based on straight-line book depreciation. Bonus and MACRS depreciation is a tax adjustment resulting in deferred tax liabilities that are not allocated out to the jurisdictions. Prior to the Duke Energy Share Services ("DESS") (Duke Energy entity for the former, Cinergy Services, Inc. service company that supported the Duke Energy Indiana predecessor company, PSI Energy, Inc., and other Cinergy companies) being merged with DEBS on July 1, 2008, the DESS service company (and Cinergy Services, Inc. service company before it) did allocate out income tax expense. At the point that DESS merged into DEBS, the DESS company had a deferred tax asset of $109 million. The jurisdictions received the benefit of this, but the reversal of this asset stayed on DEBS. The jurisdictions have not been charged for this tax expense and we currently are not seeking reimbursement. The return on rate base Mr. Kollen refers to is a calculation based on an apportionment of DEBS assets to Duke Energy Indiana and the equity return is grossed up for taxes to arrive at a pre-tax amount. This calculation results in a monthly journal entry that creates current taxable income on DEBS and a current deductible expense for the jurisdiction. In 2018 the gross-up was adjusted for the federal change in tax rates from 36% to 21%. Therefore, there is no deferred taxes that need to be adjusted or distributed as part of this process.

Ms. Douglas disagreed with OUCC witness Kollen regarding the use of the state income rate. She stated the test period is calendar year 2020 and 5.375% is the appropriate calculated (blended) Indiana statutory income tax rate for a 2020 calendar year tax payer. She noted that her position was supported by the Commission's approval of a blended state income rate for IPL in Cause No. 45029, and the use of a blended income tax rate by I&M and NIPSCO in their respective recent rate cases (Cause Nos. 45235 and 45159).

Ms. Douglas also disagreed with Witness Kollen's recommendation that Duke Energy Indiana track the future reductions in the state income rate down to the final 4.9% rate using Rider 67. She reiterated that the state income tax rate used in the Company's case-in-chief is appropriate given the test period and consistent with other rate cases. She indicated the Company manages tax expense between base rate cases, with earned return and net operating income, subject to check in the FAC return and expense tests. Ms. Douglas said Mr. Kollen's proposal is not consistent with traditional Indiana practice.

The next subject Ms. Douglas addressed in her rebuttal was the amortization of deferred federal protected excess ADIT. She indicated the protected portion of Excess ADIT is required to be returned to customers in a prescribed way using ARAM. Ms. Douglas testified she agreed with OUCC witness Blakley and IG witness Gorman that there is no requirement that the 2018 and 2019 protected Excess ADIT be returned to customers using ARAM because once the protected Excess ADIT is deferred, it takes on the same nature as unprotected Excess ADIT, which can be returned to customers more quickly than under the prescribed ARAM methodology. While she said the Company agrees as a rate mitigation measure to shorten its amortization period, it believes a more appropriate period would be the remaining amortization period for refunding unprotected Excess ADIT to customers under the terms of the TCJA Settlement. She then noted a reasonable compromise position from ARAM to eight years for amortization results in an annual amortization amount on a grossed-up basis of $5.9 million per year and an incremental refund to customers via Rider 67 of approximately $4.9 million per year over the Company's case-in-chief position.

In rebuttal to IG witness Gorman, Ms. Douglas testified there is not a requirement for certain prescribed method for Indiana state Excess ADIT amortization, and the Company agrees to net the pre-2011 regulatory asset and post-2010 regulatory liability and use the same amortization period going forward for both pieces. She stated the Company also agrees to include the netted amortization amount in its cost of service for purposes of setting the rate base in this proceeding.

As an additional rate mitigation measure, Ms. Douglas testified the Company agrees to accelerate the amortization from what was proposed in the case-in-chief to eight years consistent with Mr. Blakley's 8-year recommendation. However, rather than using Rider 67, she stated that the amount would be refunded via base rates as Mr. Gorman proposed.

Ms. Douglas also responded to Mr.Gorman's recommendation regarding the use of the 12 CP allocation to allocate the federal excess ADIT credit from the TCJA in Rider 67. She explained that the Company had used the 4 CP allocation consistent with the Company's agreement in the Duke Energy Merger case to fully support the use of the 4 CP method in its next base rate proceeding. The Duke Industrial Group was a party to the Settlement Agreement in that proceeding. In addition, she stated that updating of allocation factors in riders upon approval of new base rates is an accepted or expected Indiana precedent. She explained that the TCJA Settlement Agreement in Cause No. 45032 S2 provides that the allocations factors for the excess ADIT credits resulting from the TCJA will use the Retail Original Cost Depreciated Rate Bas as updated in the next general base rate case proceeding. For these reasons, Mrs. Douglas stated that the use of Retail Original Cost Depreciated Rate Base developed in the Company's cost of service study in this proceeding using a 4CP allocation for production plant is the most appropriate allocation to use for Rider 67 TCJA credits considering both Settlement Agreements. Company witness Brian Davey also testified in rebuttal and agreed with the approach set forth in Ms. Douglass' rebuttal testimony regarding the treatment of federal excess ADIT and state excess ADIT. His testimony included Table 1 showing the proposed adjustments to retail revenue as a result of a variety of different rate making issues.

(V) **Commission Discussion and Findings**. Duke Energy Indiana provided evidence discussing their calculation of federal and state income taxes used in the calculation of proposed operating income, which included the state and federal income tax rates used for calculation of current and deferred income taxes, the impact of other *pro forma* adjustments on income tax expense, the Company's synchronized interest deduction, the Company's parent interest deduction calculated in accordance with the Muncie Remand, and the removal of certain Investment Tax Credit and Excess Deferred Income Tax amortization credits which have been proposed to be included in the Company's Rider 67. The OUCC took exception with several issues related to income tax expense, including: 1) the state statutory rate used in the income tax calculation; 2) the amount of excess federal ADIT to be allocated to customers, specifically recommending that a portion of excess ADIT from the Company's DEBS service company should have been allocated to Duke Energy Indiana; 3) the amortization period used for state excess ADIT; and 4) the amortization period used for deferred federal protected excess ADIT. The Industrial Group also took exception to the amortization period used for the amortization period used for state EDIT and for deferred federal protected EDIT. In addition, the Industrial Group took exception with the Company's proposed allocation of federal EDIT to customers in Rider 67. Other than these issues, no party took exception to the Company's calculation of state and federal income taxes, including the *pro forma* adjustments, calculation of synchronized interest and the Company's parent interest deduction. We therefore find that except for the disputed issues, which we will next address, that the Company's income tax calculation is reasonable. We next address each of these disputed issues.

We first address the issue of the state income tax rate. Duke Energy Indiana used the annual state statutory blended rate of 5.375% for the 2020 test period to calculate current income taxes and in its revenue conversion factor calculation, and the final step of state income tax reductions which will become effective July 1, 2021, under current law for calculation of deferred income taxes. The OUCC did not disagree that 5.375% was the appropriate annual rate for 2020. Instead, they proposed the 4.9% rate that will go into effect July 1, 2021, would be the more appropriate rate to use for current income tax and the revenue requirement conversion factor because the 5.375% rate is only temporary. They proposed that rates should be set using the lower 4.9% rate, but that Rider 67 be used to step into that rate to allow the Company to temporarily recover the differential as the income tax rate phases down. The Company disagreed, noting that this Commission has previously approved use of the annual blended rate appropriate for the test period in other recent rate cases during the period of the stepped reductions in state income tax and that state income tax expense is an operating income item that is generally managed by the Company between rate cases, subject to check in the FAC return and expense. Consistent with our finding regarding changes in O&M expense for Gallagher Units 2 and 4 that will be retired in the near future but outside the test period, we believe the statutory rate for state income taxes that will be effective in 2020 is the appropriate rate to use for state income taxes and we so find. This is consistent with our approvals of state income tax rates used in other recent rate cases for Indiana electrical utilities. We also note that customers are benefitting from the Company's use of the final 4.9% rate for calculation of deferred income tax expense.

We next address the issue of DEBS excess ADIT. The OUCC recommended that a portion of the excess ADIT recorded on the books of the Company's service company affiliate DEBS should have been allocated to Duke Energy Indiana in the same manner that DEBS depreciation expense is allocated and then passed back to customers as a one-time credit in Rider 67. However, the Company provided evidence in Rebuttal that income taxes are maintained on the books of DEBS and not allocated out to utilities and that any deferred income taxes on DEBS' books are temporary differences and have always been maintained at DEBS, and any adjustments to deferred income taxes through the income statement, such as occurred for the federal income tax reduction, should remain on DEBS. We are unpersuaded by the OUCC's argument and are not inclined to require the Company to make an adjustment for ratemaking for this excess federal ADIT issue that would result in inconsistency with the Company's accounting for income taxes and service company allocations. Further, the DEBS credits to income tax expense that the OUCC proposes be refunded to Duke Energy Indiana customers were incurred in 2018 as a result of the 2017 Federal Tax Cuts and Jobs Act, for which we established a generic proceeding and subdocket for Duke Energy Indiana in Cause No. 45032 S2, and we find that this issue would have better been addressed by the OUCC in that proceeding. Therefore we find that no allocation of past DEBS income tax credits resulting from the federal income tax reduction are required by the Company.

We now address the amortization periods for the federal and state excess ADIT. Regarding state excess ADIT, we note that the Company agreed with the OUCC's recommendation to pass such benefits back to customers over an 8 year period . We believe eight years is a reasonable time period as it aligns with the period over which state corporate taxes have been reduced. Further, Ms. Douglas concluded that this pass-back could be included in base rates as proposed by Mr. Gorman. We agree that approach is a reasonable balance of the parties' positions on the issue.

Regarding federal excess ADIT, we note that the Company's initial proposal was to pass back these credits over the life of the assets that gave rise to them. However, because the 2018 and 2019 protected excess ADIT has now become unprotected, there is no requirement under the law to do so. As such, we find persuasive arguments to pass these benefits back to customers earlier. OUCC and Industrial Group both proposed three-year amortization periods. Duke Energy Indiana proposed to pass them back over eight years. We acknowledge that eight years is consistent with the treatment of rest of the unprotected excess ADIT in the Company's federal income tax act settlement. We believe synching up the amortization period for unprotected excess ADIT to the eight remaining years is a reasonable and fair outcome.

Finally, we address the allocation method to be used for the pass back of the excess federal ADIT using Rider 67. Industrial Group witness Gorman recommended the funds be returned to customers in the same manner in which the rates were collected from customers using a 12 coincident peak ("CP") allocation methodology, even though he supports moving to a 4 CP allocation method going forward for base rates and riders. Duke Energy Indiana disagrees with singling out this one credit item to continue to use the 12 CP allocation factor. Rather, the Company proposes the updated 4 CP allocation factors in Credit Rider 67 be used. We agree that going forward base rates and riders should all be updated to use the same allocation factors approved in this proceeding based on the 4 CP methodology, to do otherwise for one credit item would unnecessarily complicates the rider filing and provide for inconsistency between costs and credit allocations.

(B) Utility Receipts Tax.

(I) Petitioner's Evidence. Petitioner's witness Graft testified in support of Petitioner's Exhibit 6-E (CLG), Schedule OTX2, which removed all Indiana URT expense from the Company's test period operating expenses. She testified that currently, the 1.4% URT is embedded in base rates or rider rates as part of the revenue conversion factor and is included in the Company's cost of service. Ms. Graft stated the Company is proposing to present URT as a separate line item on customer bills as an addition to the cost of utility services similar to sales tax, which eliminates the need for the Company to include a provision for the URT in the revenue conversion factor and the need for the Company to include URT in its cost of service. In his revised direct testimony, Company witness Mr. Davey discussed that the Company did not initially include URT in its customer bill impact analysis and clarified the impact of URT on the proposed rate increase.

Company witness Mr. Panizza stated that Ms. Graft's proposal to separately state URT as a line item on customer bills comports with Indiana Code 6-2.3-3-4(a), which outlines the requirements for the URT.

(II) Industrial Group's Evidence. With respect to the presentation of the Indiana URT, Mr. Gorman contended the Company's September 9, 2019 testimony only partially resolved the URT issue. He added that continued citation to the base rate increase of 15.43% even after the URT error was caught was misleading, because it is inappropriate to calculate an increase by including taxes in the "before" figure while failing to include taxes in the "after" figure. Mr. Gorman noted that Company witness Davey identified the correct Company-wide increase of 17% but left out the correct dollar figure for the Company's requested rate increase. Mr. Gorman testified the correct amount of Duke Energy Indiana's requested rate increase is $434.3 million, which includes $41.2 million of URT.

(III) Petitioner's Rebuttal Evidence. Company witness Davey provided testimony in rebuttal to IG witness Gorman's testimony related to the URT impacts on the Company's rate increase request. In the Company's July 2019 filing, Mr. Davey indicated the proposed rate increase for total retail customers was 15%. The Company's September 9, 2019 filing clarified the proposed rate increase for total retail was 17% and not 15% when the URT is considered. Mr. Davey stated the proposed rate-making change for URT provides the flexibility that if the tax is decreased in the future, customers will receive the benefit immediately without waiting for the next base rate case.

Mr. Davey stated Mr. Gorman agrees the proposed rate increase with URT is 17%, but he claims the Company did not fully correct a perceived problem with the dollar figure for Duke Energy Indiana's requested increase. However, the Company's proposed base rate revenue requirement and its proposed base rates in this proceeding are properly reflected without the URT, as the URT will not be included in base rate revenue requirements under the Company's proposal, but rather will be included as a separate line item on the customer's bill. Mr. Davey noted that Tables 1 through 4 in his rebuttal testimony address Mr. Gorman's point of concern.

(IV) Commission Discussion and Findings. Regarding Petitioner's proposal to present URT as a separate line item on customer bills, we find this to be reasonable and approve this request. As it relates to the Industrial Group's concern regarding the communication of the impact of URT on a customer bill, we find that the Company has adequately addressed those concerns.

12. **Conclusion Regarding Petitioner's *Pro Forma* Jurisdictional Electric Net Operating Income.** On the basis of the foregoing, we find that Petitioner's *pro forma* jurisdictional electric net operating income under present rates excluding revenue remaining in riders, adjusted to a level which fairly represents its forecasted operations is $342,359,000, summarized as follows:

$ in Millions under current rates	2020
Total Operating Revenues	2,518
Operating Expenses	
Fuel & Purchased Power Expense	780
Operation and Maintenance	576
Depreciation and Amortization	694
Property and other Taxes	69
Income Taxes	57
Total Operating Expenses	2,176
Operating Income	342

When applied to the original cost (also in this case, fair value) rate base determined for Petitioner above, this operating income produces a return of only 3.35%, which is outside the range established in our above findings. Accordingly, on the basis of the evidence and the foregoing determinations, we find that the electric operating income to Petitioner, under its present rates for the electric utility service rendered and to be rendered by it, is not sufficient to provide Petitioner a fair return upon the fair value of its electric properties used and useful for the convenience of the public for the forecasted test period and beyond. Therefore, Petitioner's current rates are unjust and unreasonable.

13. **Rate Level to be Authorized**. We find that a net jurisdictional operating income, excluding revenue remaining in riders, of $611,712,000 is hereby found to be a fair return upon the fair value of Petitioner's electric property used and useful and reasonably necessary for the convenience of the public. This provides a fair rate of return of approximately 6.00% which is within the range of reasonableness established in our previous findings. In order to provide such utility operating income, an increase in Petitioner's gross annual retail electric operating revenues to $361,790,000 (excluding items remaining in riders and the utility receipts tax) is required, The increase in revenues will give rise to increased tax expense and as a result, total operating expenses will be $2,268,030,000 On that basis, we find that Petitioner's *pro forma* operating results will be:

$ in Millions under current rates	2020
Total Operating Revenues	2,880
Operating Expenses	
Fuel & Purchased Power Expense	780
Operation and Maintenance	577
Depreciation and Amortization	694
Property and other Taxes	69
Income Taxes	148
Total Operating Expenses	2,268
Operating Income	612

14. Cost Allocation.

a. Jurisdictional Separation Study.

i. **Petitioner's Evidence.** Company witness Diaz supported and explained the Company's jurisdictional separation study. She explained that the financial forecast was the starting point for the study, followed by the segregation of the Company's customers into three main categories: one high-pressure steam customer, wholesale electric customers that purchase firm power from the Company and resell it, and retail electric customers that purchase power from the Company as ultimate customers.

Ms. Diaz testified that a steam study was performed to allocate Cayuga Station rate base items, O&M expenses, administrative and general expenses, depreciation, amortization, and taxes to the steam customer. Next, she explained, demand and energy allocators were developed for the Company's non-jurisdictional customers, and production costs and related production expenses were allocated to firm native load wholesale customers -- not including the one wholesale 100 MW contract that is considered a short-term bundled non-native contract. The Company developed the system peak demand (and usage) and the applicable wholesale customers' share of the system peak (and usage), with the remainder being the retail portion of Duke Energy Indiana's total system demand (and usage), which represents the retail customers' portion of the maximum electricity load and usage imposed on Duke Energy Indiana's electric system. She observed that the wholesale demands and usage for the forecasted 2020 period approximated 8%, which approximates the same percentage from the last base rate case.

She stated that forecasted revenues related to local facilities (distribution) and MISO (transmission) were assigned 100% to retail as the forecasted costs to supply the wholesale distribution and transmission services were assigned 100% to retail. She testified that both Duke Energy Indiana's forecasted Joint Transmission System costs and revenues were assigned 100% to retail.

She testified that forecasted net plant in-service and associated O&M expenses, as well as revenues, related to Wabash Valley's and IMPA's shares for Gibson Unit 5 and Wabash Valley's share of Vermillion station were excluded from the development of retail rates, as were costs associated with a 50 MW wholesale contract associated with Henry County Generating Station.

She noted that these non-jurisdictional customers (including the steam customer) and associated costs were treated as non-jurisdictional for purposes of this proceeding, while the retail electric customers and other retail assignments are the jurisdictional customers and activity for purposes of this proceeding.

ii. Industrial Group's Evidence. Industrial Group witness Dauphinais contended that the short-term 100 MW bundled capacity and energy contract should be allocated to the wholesale jurisdiction in the jurisdictional separation study, in the same manner as are traditional wholesale firm native load sales contracts. Additionally, Mr. Dauphinais argued that the Commission should impute as long-term wholesale sales for jurisdictional study purposes, the amount of historical long-term wholesale sales that have terminated since 2013 that have not been replaced with new long-term wholesale contracts.

iii. Petitioner's Rebuttal Evidence. In rebuttal testimony, Company witness Davey testified that the Company disagrees with treating short-term bundled non-native sales as if they are traditional wholesale native-load sales in the jurisdiction separation study. Mr. Davey testified that the Company's net revenue-sharing proposal is much-more reasonable for these types of contracts, recognizing the difference between these short-term contracts and long-term traditional native-load contracts. Further, Mr. Davey testified that imputing a nonexistent wholesale sale in the jurisdiction separation study is unprecedented and would be a clear departure from traditional ratemaking. Further, it would be unreasonable in this instance, he emphasized, as retail customers are already being allocated a lower percentage of the production demand costs than they were at the time of the last base rate case. He also testified that the Company makes no long-term planning decisions based on this contract, further differentiating it from traditional wholesale native load sales.

iv. Commission Discussion and Findings. We agree with Petitioner that it would be unprecedented and unreasonable to impute a level of hypothetical wholesale sales and allocate costs to such non-existent sales for ratemaking purposes. We decline to set rates based upon a hypothetical situation (i.e., imputed wholesale sales). The Indiana Supreme Court has held that a utility, "cannot be charged in a rate hearing for failure to engage in a large scale financial operation that has never taken place. . . . The statute does not permit the fixing of rates on a hypothesis or a situation never in existence." *See Public Service Comm'n v. City of Indianapolis* (1956) 131 N.E.2d 308, 316-317. Although we are dealing with a forecasted rather than a historical test period here, the use of a future test period is not a license to engage in speculative and hypothetical ratemaking. There is a world of difference between a forecast, supported by evidence of a robust forecasting process, and a purely hypothetical situation based simply on a desire for a lower rate. We also note that Petitioner's evidence shows that the market for traditionally-priced wholesale sales has changed dramatically, and there is no evidence that Petitioner is not making good faith efforts to replace terminating traditional wholesale contracts with new contracts. Indeed, the Company's new strategy of pursuing short-term bundled sales is evidence of its efforts to do just that. We also note that Ms. Diaz testified that the level of sales allocated to wholesale in the jurisdictional separation study is approximately the same as it was in the Company's last rate case several years ago, and Mr. Davey testified that in this case, retail customers are being allocated a lower percentage of production demand costs than they were in the last base rate case. For these reasons, we reject Mr. Dauphinais' proposed adjustment to the separation study allocation.

We also reject Mr. Dauphinais' proposal to allocate the one existing short-term bundled sales contract to the wholesale jurisdiction in the separation study. The testimony of Mr. Swez and Mr. Davey make clear that this contract differs markedly from traditional long-term wholesale native load contracts that are allocated to wholesale in the jurisdictional separation study process. The evidence shows this new contract strategy is an attempt to opportunistically create value for the Company and its retail customers, by creating sales revenues that would otherwise not exist in the current power market. Additionally, and significantly, the short-term nature of these contracts militates against Mr. Dauphinais' proposal. In particular, this specific 100 MW contract expires in 2021, mere months following our decision in this Cause. To the extent possible, rates should be established that are representative of a utility's ongoing operations while those rates will be in effect. The evidence indicates that the existence of this contract is not representative of ongoing Company operations in this case. And significantly, the evidence shows that the Company does not plan or build for this contract, in contrast to traditional wholesale native load customers. For these reasons, we reject the proposal to allocate costs to this short-term bundled contract in the jurisdictional separation study.

b. Class Cost of Service Study.

i. Petitioner's Evidence. Petitioner's witness Diaz presented the Company's class cost-of-service study, which allocates total Indiana retail jurisdictional rate base, revenues and expenses to each rate schedule. She explained that the Company used a 3rd party application, PowerPlan regulatory suite, to support this base rate case proceeding. She further explained that PowerPlan assigned data into function (Production, Transmission, Distribution, and Customer) and sub-functions. The function data then populates the *Separation* step, wherein the data is separated between a Steam Customer and all other Electric customers. The electric data feeds and populates the *Jurisdiction Separation* step, wherein the data is separated between Indiana Retail and Wholesale. Ms. Diaz testified that the Indiana Retail data feeds and populates the *Retail Rate Codes*, wherein the data is separated by each rate schedule and grouped into customer classes for rate design processing.

Ms. Diaz noted that in its retail cost of service study, the Company performed allocations for production plant using both a 4-CP and 12-CP methodology to its rate schedules based on the Commission's directive that it do so in Cause No. 42873. Ms. Diaz testified that the 4-CP demands used were the average of the maximum retail demands for the historical twelve-month period ended June 30, 2018. The 4-CP peak period average included the months of August 2017, September 2017, January 2018, and June 2018. Ms. Diaz stated that the Company elected to apply 5.1% as the subsidy/excess reduction in lieu of a larger subsidy/excess reduction that would have increased proposed residential rates more but lowered the rate impacts to other classes.

ii. OUCC's Evidence. Messrs. Eckert, Watkins, expressed displeasure at the Company's use of third-party software, which required an on-site visit to review the Company's Cost of Service Study. OUCC witness Watkins testified that while it is his opinion that the 4-CP method does not reasonably reflect cost causation, the OUCC previously agreed not to oppose the 4-CP method in Cause No. 42873. Mr. Watkins testified that settlements involve give and take and Mr. Watson stated that he was not privy to why that was part of the settlement. Nonetheless, Mr. Watkins stated that the agreement not to oppose does not change the flaws in the 4-CP methodology. Mr. Watkins stated that cost allocation methods that only consider peak loads (demands) such as the 1-CP and 4-CP do not reasonably reflect cost causation for electric utilities because these methods totally ignore the type and level of investments made to provide generation service.

iii. Industrial Group's Evidence. Industrial Group witness Phillips recommended that the Company allocate its production plant and transmission plant on a 4-CP method. Mr. Phillips stated that the average of the 12 monthly coincident peak demand method ("12-CP") is no longer reflective of Duke's current or projected loads, or those used by MISO to determine Duke's reserve margin and capacity requirements. Mr. Phillips further testified that Duke's proposed method of distributing its requested rate increase to classes reduces existing interclass subsidies by only 5% and results in rates that continue to contain massive subsidies and are not reflective of cost. Mr. Phillips stated that a much greater level of subsidy reduction is necessary and appropriate. In cross-answering testimony, Mr. Phillips testified that attempting to classify the majority (70%) of Duke's production investment as being energy-related is flawed and inconsistent with prior Commission findings. Also, in his cross-answering testimony, Mr. Phillips contended that the OUCC's argument to not reduce the subsidy is contrary to the policy of the Commission.

iv. Joint Intervenors' Evidence. Joint Intervenors witness Wallach, Schlissel, and Howat repeated allegations that were included in the Motion to Amend Procedural Schedule regarding Petitioner's Cost of Service Study. Mr. Wallach testified that the Company's cost of service study over-allocates production plant costs to classes with low load factors by inappropriately classifying all such costs as demand-related. Mr. Wallach asserted it would be proper to reclassify the Company's production plant costs using the Equivalent Peaker method. Mr. Wallach testified that the cost of service study compounds this error by allocating demand-related plant costs based on each class's contribution to system peak in the four months of the year with the highest system peak demands ("4-CP allocator"), rather than based on the contribution to system peak throughout the year ("12-CP allocator"). In addition, Mr. Wallach testified that the Company's cost of service study over-allocates distribution plant costs to low-coincidence classes by allocating demand-related distribution plant costs on the basis of customer maximum demand, rather than based on customer demand coincident with class peaks. In cross-answering testimony, Mr. Wallach reiterated his opinion that the 4-CP allocator does not reasonably reflect the fact that system peak demands in all months of the year contribute to the Company's reserve requirements and need for reserve capacity.

v. Petitioner's Rebuttal. Messrs. Pinegar and Davey addressed concerns with the Cost of Service Study. Mr. Pinegar explained that the Company sought to be transparent in addressing concerns with the Cost of Service Study. He testified that, although Petitioner complied with the rules, Company personnel created an Excel-based replica of its cost of service model for the use of the parties and agreed to run modeling changes at their request. Mr. Davey testified that using the PowerPlan proprietary model for the cost of service study has benefits in terms of accuracy of data, consistency across jurisdictions, and efficiency because it has direct input feeds from the Company's forecasting tool and accounting tools minimize the chance of error.

Ms. Diaz testified that she did not agree with OUCC witness Watkins' testimony that the 4-CP methodology does not reasonably reflect cost causation. Ms. Diaz noted the selection of a 4-CP or 12-CP is at the Commission's discretion. However, Ms. Diaz stated that a company with a relatively flat load profile throughout the year would typically allocate demand costs on a 12-CP basis because a 12-CP methodology allocates demand costs based on an assumption that capacity is built to meet the demand season-to-season, month-to-month and not just the maximum load on the system at any one given time or any one segment of the year. In contrast, Ms. Diaz stated that a peaking utility would allocate demand costs more typically on a multiple-month basis, which assumes that the load profile has a pronounced peak during those peak usage months.

Ms. Diaz stated that if the cost allocation for production plant were allocated 70% energy/30% demand as proposed by Mr. Wallach, it would shift the design of rates by increasing energy charges more than what is already being proposed as part of this proceeding. Ms. Diaz stated that historically, this Commission has not accepted an electric cost of service study that classifies a portion of production plant as energy-related and has consistently rejected the use of this methodology and there is no reason to depart from this practice. Ms. Diaz noted that utilizing a blend of demand and energy to allocate production investment contradicts the argument that there are peaks on the Duke Energy Indiana electric system.

Ms. Diaz also disagreed with Mr. Wallach's recommendation that distribution plant costs be allocated based on diversified class demand instead of non-coincident peak and that costs of primary poles and conductors be allocated on diversified class demand exclusively. Ms. Diaz noted that Duke Energy Indiana's practice for allocation of secondary poles, conductors, and line transformers, which uses NCP demand that is the average of the 12 individual customer level peaks has been in place since 1994, when it was approved in Cause No. 40003. Ms. Diaz stated there have not been substantive changes in how customers connect to the distribution system from prior retail cases which would warrant a change in cost assignment in this proceeding.

Ms. Diaz stated that the Company elected to apply a modest 5.1% as the subsidy/excess reduction in lieu of a larger subsidy/excess reduction that would have increased proposed residential rates more while lowering the rate impacts to other classes. Ms. Diaz stated the decision as to which subsidy/excess percentage to apply was a result of the overall strategic decision described by Duke Energy Indiana to keep residential customers at a proposed increase of lower than 20% (exclusive of taxes separately shown on a customer's bill) while also considering the proposed rate of increase across the rest of the retail classes.

vi. Kroger's Cross-Answering Testimony. Kroger witness Bieber recommended the Commission reject Mr. Wallach's utilization of the Equivalent Peaker method to classify production costs. He also testified the Commission should accept Mr. Philips' recommendation to use the minimum distribution system method to classify certain distribution plant costs as customer-related.

vii. Commission Discussion and Findings.

As a threshold matter, many parties argued throughout this case that Duke's petition and case-in-chief filed on July 2, 2019, were incomplete, poorly documented, and internally inconsistent. Duke's case-in-chief is not contemplated or governed by the existing MSFR rule inasmuch as the Duke case involves a future test year presented in an incredibly voluminous and complex filing which was incomplete and otherwise deficient in manifold respects at the time of its filing. The existing MSFR rule at 170 IAC 1-5-1 et seq. was written at a time when forward-looking test years were not permitted and when many of these filings were done on paper (filed October 28, 1998, and subsequently readopted in later years). The MSFR rule must be read in conjunction with the later issued General Administrative Order ("GAO") 2013-5. GAO 2013-5 II.A.2(b) states, "While recognizing the MSFR contemplates a historic test period, Indiana Code §8-1-2-42.7 allows a utility to file within 270 days of the close of the historic test period." It goes onto say that, "If the utility proposes a forward-looking or hybrid test year as authorized by Ind. Code §8-1-2-42.7, the MSFR should still serve as guidance as to the categories of information that are appropriate for inclusion as working papers." The GAO elaborates on what is needed in addition to the MSFRs when a forward-looking test year is used at GAO 2013-5 II.A.2: "(c) If the utility chooses a forward-looking test period, the utility should also provide supporting documentation, including any supporting calculations, for any changes between the historic base period and the test period chosen. Each change to the historic base period should be reflected as an individual adjustment in the revenue requirements schedules and explained in testimony. (d) To the extent a forward-looking test year employs a model, that model must be completely transparent, the assumptions fully explicit, and the results fully replicable by any party and by Commission staff."

The OUCC and other intervening parties first contacted Duke on September 6, 2019, regarding major deficiencies in the Company's petition, particularly the lack of underlying formulas in Duke's cost of service study, making it impossible for these parties to see how Duke was classifying, allocating, and functionalizing costs. Prior to the non-Duke parties' case-in-chief due date, CAC, the OUCC, and other intervenors devoted much time and resources attempting to remedy these flaws through multiple conference calls with Duke and informal data requests. JI Ex. 1, pp. 2-3. Per these parties' request, Duke ultimately filed an Excel based replica of its Cost of Service Study with the Commission on October 11, 2019.

Additional issues were noted by the OUCC and other intervenors in their Joint Motion to Amend Procedural Schedule, for Appropriate Relief, and for Expedited Briefing and subsequent Reply, flagging other errors and deficiencies in Duke's case-in-chief. For example, on Monday, October 21, at 9:20 pm, Duke provided certain revenue proofs, just 9 days before the current OUCC and intervenors' testimony due date. These spreadsheets contained tie outs of Duke's base rate revenues at present rates, a fundamental part of any rate case, yet the spreadsheets did not contain a proof of tracker revenues at current rates. Duke Witness Douglas indicates in her testimony total present tracker revenue of $380,011,185 ($17,683,380 remaining in trackers and $362,327,805 moving to base rates), while Duke Witness Bailey's rate design uses tracker revenues at current rates of $374,062,533. This put much strain on the non-Duke parties and made it difficult for them to put together an analysis to determine how the revenues were calculated as the spreadsheets were still missing underlying formulae as of the date of these parties' Reply in support of the Joint Motion.

Despite this Commission not granting the relief requested by the OUCC and other intervenors at that time, we do agree that the data production delays and other glaring deficiencies in Duke's filing further compounded the voluminous and complex character of Duke's case-in-chief filing. It was Duke's responsibility to file complete and transparent documentation to allow a thorough review by Commission staff and other parties of the Company's forecasting methodology, data sources, and assumptions. Duke claims it filed the required information, but it did not insofar as it did not provide it in a transparent format which would allow parties or the Commission to determine step-by-step how that information for the 2020 future test year had been derived and adjusted from the 2018 base year. It is the plain and manifest intent of the Commission in both the MSFRs and GAO 2013-5 that parties should have access to transparent information from the utility that allows them to understand and verify the forecasted and adjusted data. Only then can parties assert their positions and can the Commission rule on the validity of Duke's forecasted and adjusted data in setting new rates.

We note that Duke's conduct and presentation of evidence in this regard is at play in our decisions in this case. In particular, a cost of service study is a critical document underlying any general rate case, without which parties and the Commission could not adequately perform their analyses and present their evidence.

The Company is requesting that electric retail base rates be increased on average by 15.7% in order to recover an expected revenue deficiency of about $394.6 million in the 2020 test year.[32] Of the total $394.6 million requested base revenue increase, DEI proposes to allocate about $191.7 million to residential customers. This amount represents a 19.4% increase over residential test-year revenues under current rates.

According to DEI witness Maria T. Diaz, the Company's COSS served as the basis for its revenue allocation proposal. Specifically, the Company's COSS indicates that residential base revenues would have to be increased by about $283.7 million, or about 28.7%, to achieve the requested rate of return.[33] Of that total increase, the Company's COSS indicates that about $96.9 million represents the increase required to achieve the system average rate of return under current rates.[34] In other words, the Company's COSS indicates that the residential class is currently under-earning relative to the system average achieved rate of return and that the current "subsidy" amounts to $96.9 million. According to Ms. Diaz, DEI proposes to increase residential base revenues to eliminate 5.1% of this current subsidy.

The primary purpose of a cost of service study is to allocate a utility's total revenue requirements to individual customers or rate classes in a manner that reasonably reflects each class's responsibility for such revenue requirements. In other words, the primary purpose of a cost of service study is to attribute costs to customer classes based on how those classes cause such costs to be incurred. In order to allocate costs to customer classes, the COSS first separates total costs into production, transmission, distribution, and customer functions. Costs in each function

[32] MSFR Workpaper COSS24-MTD. The $394.6 million amount is net of utility receipts tax revenue, which DEI proposes to recover through a separate surcharge on customers' bills.
[33] Calculated based on data provided in MSFR Workpaper COSS24-MTD and COSS20-MTD.
[34] MSFR Workpaper COSS20-MTD.

are then classified as energy-, demand-, or customer-related based on whether costs are considered to be "caused" by energy sales, peak demand, or the number of customers, respectively. Finally, costs classified as either energy-, demand-, or customer-related are allocated to customer classes in proportion to each class's contribution to total-system energy sales, peak demand, or number of customers, respectively.

Based on the evidence and arguments provided in this proceeding, as described below, this Commission is concerned that the Company's COSS does not allocate costs to customer classes in a manner that reasonably reflects each class's responsibility for such costs. The Company's proposal for allocating the requested revenue deficiency among the customer classes relies solely on the results of a cost-of-service study that does not allocate costs to customer classes in a manner that reasonably reflects each class's responsibility for such costs. Correcting just for these misallocations in the Company's COSS would reduce the allocation of the requested revenue requirement to the residential class by about $104 million.

(1) Whether Duke Misallocated Production Plant Costs

The Company's COSS over-allocates production plant costs to classes with low load factors by inappropriately classifying all such costs as demand-related.[35] The Company's COSS classifies production plant costs as if such costs were incurred solely for the purposes of meeting system reliability requirements, and not at all for the purposes of minimizing the cost of meeting energy requirements. However, under typical generation expansion planning practices, plant investment choices are driven by both reliability and energy requirements. As explained in NARUC's *Electric Utility Cost Allocation Manual*:

> Cost causation is a phrase referring to an attempt to determine what, or who, is causing costs to be incurred by the utility. For the generation function, cost causation attempts to determine what influences a utility's production plant investment decisions. Cost causation considers: (1) that utilities add capacity to meet critical system planning reliability criteria such as loss of load probability, loss of load hours, reserve margin, or expected unserved energy; and (2) that the utility's energy load or load duration curve is a major indicator of the type of plant needed. The type of plant installed determines the cost of the additional capacity. This approach is well represented among the energy weighting methods of cost allocation.[36]

From a cost-causation perspective, investments in peaking plant are appropriately classified as demand-related, since peaking units typically would be the least-cost generation option for meeting an increase in peak demand and planning reserve requirements. On the other hand, baseload or intermediate plant costs *in excess of peaking plant costs* (so-called "capitalized energy" costs) should be classified as energy-related, since these incremental costs are incurred to minimize the total cost of meeting an increase in energy requirements. The Company's COSS misclassifies these capitalized energy costs as demand-related. As a result, the Company's COSS

[35] Load factor is defined as the ratio of average demand to peak demand, where average demand is annual energy requirements divided by 8760 (i.e., the number of hours in a year).
[36] National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual*, 38–39 (January, 1992) (JI Ex. 1, Attachment JFW-4)[hereinafter "*NARUC Manual*"].

over-allocates capitalized energy costs to the residential class and under-allocates such costs to the industrial classes since the residential class has a lower load factor than the industrial classes.[37]

It is inappropriate to classify all production plant costs as demand-related because it is inconsistent with cost-causation. There are other classification methods that would classify the Company's production plant costs in a manner that reasonably reflects cost causation. For example, the Equivalent Peaker classification method classifies production plant costs in a manner that reasonably reflects investment decision-making under typical generation expansion planning practices, as described above. According to the NARUC *Electric Utility Cost Allocation Manual*:

> Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. . . . The premises of this and other peaker methods are: (1) that increases in peak demand require the addition of peaking capacity only; and (2) that utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study.[38]

JI Witness Wallach reclassified Duke's production plant costs using the Equivalent Peaker method. He estimated the demand- and energy-related portions of the Company's production plant costs based on data reported in the Company's FERC Form 1 report for 2018, calculating the demand-related portion of total plant costs for the Company's generation portfolio as the product of: (1) total plant capacity of the Company's generation portfolio; and (2) the average plant cost per kilowatt of plant capacity for the Company's gas turbines. In other words, the demand-related portion of total plant costs is what plant costs would have amounted to if the Company's generation capacity were priced at the average cost per kilowatt for its gas turbines. The energy-related (or capitalized energy) portion is then the excess of total plant costs over the demand-related portion of total plant costs. Using this approach, Mr. Wallach estimated that 30% of the Company's production plant costs are demand-related and about 70% are energy-related, which we find to be more appropriate and reasonable.

(2) Whether Duke Misallocated Demand-Related Production Plant Costs.

The COSS then compounds the above error by allocating demand-related plant costs based on each class's contribution to system peak in the four months of the year with the highest system peak demands ("4CP allocator"), rather than based on the contribution to system peak throughout the year ("12CP allocator"). The Company's COSS uses a proposed 4CP allocator, which allocates such costs in proportion to each class's contribution to system peak demand in the four

[37] A customer class with a low load factor (relative to other classes) will be allocated a greater percentage of demand-related costs than energy-related costs because that class's percentage contribution to total system demand is larger than its contribution to total system energy requirement.
[38] *NARUC Manual*, at pp. 52–53.

months of the year with the highest system peaks. Specifically, with the 4CP allocator, each class's percentage share of total demand-related production plant costs is calculated as the ratio of: (1) the average of the class's demand at time of system peak in the months of January, June, August, and September; and (2) the average of system peak demands in those same four months.

According to DEI witness Diaz, the Company's long-standing practice prior to this proceeding has been to allocate demand-related production plant costs in proportion to each class's contribution to the average of the 12 monthly system peaks. In fact, according to Ms. Diaz, the Company's use of the 12CP allocator "was approved at least 13 times since 1971 in the Company's retail rate case proceedings." Revised Petitioner's Ex. 7, p. 6, lines 11–12. DEI abandoned such a long-standing practice in this proceeding as part of a 2005 settlement agreement in Cause No. 42873, where DEI agreed to employ a 4CP allocator in the next rate case that followed that Cause. This current proceeding is the first DEI rate case since the Commission approved the settlement agreement in Cause No. 42873.

However, the Commission did not approve the use of the 4CP allocator as part of its approval of the settlement agreement in Cause No. 42873. To the contrary, the Commission explicitly declined to rule on the reasonableness of the 4CP allocator: "While the Settlement Agreement sets forth an agreed upon framework under which certain parties intend to address rate design issues in PSI's next rate case, we agree with Mr. Fagan that as the issue is sufficiently unrelated to the matter presented to us for approval in this Cause it is not necessary or appropriate for the Commission to affirm this understanding and approach as part of this proceeding." IURC Final Order, Cause No. 42873, 19 (March 15, 2006).

Between the two allocators, 4CP or 12CP, the 12CP allocator more reasonably reflects the drivers of the Company's investments in demand-related production costs and therefore allocates such costs more consistently with cost-causation principles. The 4CP allocator allocates demand-related production plant costs on the basis of each class's contribution to system peaks in the four months of the year with the highest system peak demands. As discussed above, demand-related production plant costs are incurred for the purposes of meeting reserve requirements. Thus, the 4CP allocator allocates demand-related production plant costs consistent with the notion that the Company's planning reserve requirements are driven solely by the four highest monthly system peaks in the year. In contrast, the 12CP allocator allocates demand-related production plant costs on the basis of each class's contribution to the twelve monthly system peaks. Thus, the 12CP allocator allocates demand-related production plant costs as if the Company's planning reserve requirements are driven by system peaks in all months of the year.

In reality, the Midcontinent Independent System Operator ("MISO") determines the Company's annual reserve requirements based on demand throughout the year, not just on peak demand in the four months with the highest peak demands. Specifically, MISO determines the amount of capacity required for planning reserve based on the results of a loss of load probability ("LOLP") analysis that considers the daily contribution of the Company's demand to annual loss of load expectation ("LOLE"). Although lower than demands in the peak demand months, demands in non-peak months can also contribute to annual LOLE and thus to system reserve requirements at times when margins between available capacity and demand are tight. For example, the scheduling of plant maintenance during low-demand shoulder months can reduce capacity margins during peak periods in those shoulder months and thus increase annual LOLE and reserve requirements.

Thus, the Company's investments in capacity to meet reserve requirements are driven by demand in every month, not just by the demands in peak months. Consequently, a 12CP allocator is a more reasonable measure of each class's contribution to the need for new reserve capacity than a 4CP allocator, and thus this Commission rejects the Company's proposed 4CP allocator.

(3) Whether Duke Misallocated Distribution Plant Costs

The Company's COSS also over-allocates distribution plant costs to low-coincidence classes by allocating demand-related distribution plant costs on the basis of customer maximum demand, rather than based on customer demand coincident with class peaks.[39] The Company's COSS allocates the costs of secondary poles, conductors, and transformers on the basis of each class's non-coincident peak demand ("NCP"). Class non-coincident peak demand in any month is derived by summing individual customers' maximum demand during the month. The NCP allocator derives each class's percentage share of secondary distribution plant costs calculated as the ratio of: (1) the average of the class's monthly NCPs over the year; and (2) the average over the year of the sum of all classes' NCPs in each month.

The Company's COSS allocates the costs of primary poles and conductors based on a weighted average of each class's NCP and diversified peak demand. Class-diversified peak demand in any month is derived by summing individual customers' demand at the time of the class peak during that month. In other words, class diversified peak demand is simply the maximum demand for the class as a whole.

The NCP allocator does not account for the effect of load diversity on distribution equipment loading and thus does not reasonably reflect the drivers of the Company's distribution plant investment. By failing to account for load diversity, the NCP allocator likely overstates the residential class's contribution to distribution costs and thus over-allocates such costs to the residential class.

Residential customers reach their individual maximum demands on different days and in different hours of the day. This diversity of demand among a group of residential customers served by a piece of distribution equipment results in a group peak demand that is lower than the sum of customers' individual maximum demands. As is typical for electric utilities, DEI sizes distribution plant to meet the group peak, not to meet the sum of customers' individual maximum demands. *See*, e.g., DEI Response to CAC Data Request 12-4(d) (JI Ex. 1, Attachment JFW-5).

The NCP allocator over-allocates costs to the residential class because it does not account for the effect of load diversity on equipment sizing and thus on equipment cost. Specifically, the NCP allocator does not account for the fact that distribution equipment serving many small residential customers can be smaller (and less expensive) than equipment that serves fewer large

[39] Coincidence is defined as the ratio of the sum of individual customer demands at the time of (i.e., coincident with) the class maximum demand to the sum of the individual customer maximum demands (regardless of when such customer maximum demands occur).

industrial customers, even when the sum of the residential maximum demands is equal to the sum of industrial maximum demands. As the number of customers served by distribution equipment increases, so too does the diversity of maximum hourly demands among those customers. And as the diversity of maximum demands increases, so too does the variance between the sum of individual customers' maximum hourly demands (i.e., group NCP) and the maximum demand for the group as a whole (i.e., group diversified demand.) By not accounting for load diversity, the NCP allocator allocates cost to classes as if the sizing and cost of distribution equipment is driven by each class's NCP rather than by the class's diversified demand on the equipment.

In order to reasonably account for the effect of load diversity, distribution plant costs should be allocated on the basis of each class's diversified peak demand ("DIV"). Specifically, each class's allocated share of distribution plant costs should be derived as the ratio of: (1) the average of the class's monthly DIVs over the year; and (2) the average over the year of the sum of all classes' DIVs in each month.

(4) Conclusion

In conclusion, we reject the Company's proposal for allocating the requested revenue deficiency because it relies solely on the results of a cost-of-service study that does not allocate costs to customer classes in a manner that reasonably reflects each class's responsibility for such costs. Correcting just for these misallocations in the Company's COSS would reduce the allocation of the requested revenue requirement to the residential class by about $104 million. Furthermore, we are concerned about the Company's proposal for reducing the current "subsidy" to the residential class. After so many years without a rate case, residential customers are facing overwhelming rate shock even without the increase necessary to reduce the alleged current "subsidy." Now is simply not the time to try to remedy the subsidies of the past. We order the Company to submit a compliance filing consistent with the findings in this section. Other parties will have 30 days to respond to Duke's compliance filing for the Commission's consideration.

~~Throughout this proceeding, various parties have raised issue regarding Duke Energy Indiana's use of a third-party proprietary software model for its cost of service study. We find that Duke Energy Indiana's case-in-chief, MSFRs, and workpapers fully complied with all applicable statutes and rules as it applies to the Cost of Service Study. Specifically, 170 IAC 1-5-15(e), (f) and (g), provide with respect to cost of service studies that: (1) such information shall be confidential and protected from disclosure, and (2) if it is impossible or impractical for the electing utility to provide such information electronically, the electing utility shall make such information available to the Commission staff and any other party (subject to a nondisclosure agreement) during normal business hours, on the electing utility's premises, a computer and all software used to create and store such information. On November 21, 2019, Commission staff made an onsite visit to review the software and several intervenors were present or available by telephone. We find that Duke Energy Indiana's Cost of Service Study fully complied with the Commission rules.~~

~~In this proceeding, we have been presented with a variety of proposals with respect to the allocation of costs to the various rate classes. For the reasons set forth below, we find that the~~

~~methodology used by Ms. Diaz, including the allocation of production cost using the 4-CP methodology, represents a sound middle-ground approach for the allocation of costs in this proceeding. We also find that the Company's proposed level of subsidy/excess reduction should be approved. We discuss the major issues raised by the parties below.~~

~~**(A) Allocation of Production Related Costs; 4-CP versus 12-CP.** In compliance with our Order in Cause No. 42873, Petitioner presented a cost of service study that allocated production plant costs using both the 4-CP and 12-CP methodologies. Industrial Group witness Phillips supported use of the 4-CP methodology. Joint Intervenors' witness Wallach recommended the Commission approve 12-CP as the allocation methodology. OUCC witness Watkins testified that even though the OUCC had agreed not to oppose the 4-CP methodology, in his opinion the 4-CP method does not reasonably reflect cost causation.~~

~~Using the 4-CP methodology represents a change in the manner in which production-related costs have been allocated in the Company's prior rate cases. In *PSI Energy, Inc.*, we held that a change in cost allocation methodology can have significant impacts on customer classes and, thus, such a change should not be lightly undertaken, especially where so much of the plant was in service at the time of the utility's last rate case, and costs were assigned on the same basis in that case. Cause No. 42359, p. 102, 2004 WL 1493966 (IURC 5/18/2004).~~

~~The evidence of record reflects that significant operational changes have taken place since Petitioner's last rate case. The Company's last rate case filed by PSI was Cause No. 42359, which was filed at the end of 2002 and was decided by Commission Order dated May 18, 2004. At that time, MISO had only recently been formed and approved by FERC as an RTO, and it was still years away from operating energy markets within its footprint. Currently, MISO establishes capacity requirements for its member utilities based on peak demand and reserve criteria. Consequently, Duke Energy Indiana's capacity needs are now determined by its contribution to the MISO system's peak, which occurs consistently in the summer period. Given the foregoing changes, we find the use a 4-CP methodology as presented by Petitioner is more reflective of cost causation.~~

~~**(B) Demand/Energy Allocators**. Petitioner proposed to classify electric generation production plant as 100% demand related. The energy-weighted demand allocation methodologies proposed by Joint Intervenors do not recognize the fact that production plant costs are fixed in nature and exist regardless of how much energy customers consume. Because production plant capacity is required to meet peak demand requirements, plant capacity costs are appropriately allocated to customers based on their contribution to peak demands, since there is a direct relationship to the demand that customers place on the system. We have consistently rejected proposals to allocate production cost based on energy consumption and we decline to do so in this proceeding.~~

~~**(C) Allocation of Distribution Plant Costs**. Joint Intervenors proposed an alternative methodology of allocating distribution plant. Joint Intervenors' proposed allocation of distribution plant fails to recognize that Duke Energy Indiana's practice for allocation of secondary poles, conductors, and line transformers, which uses NCP demand that is the average of the 12 individual customer level peaks has been in place since 1994, when it was approved in Cause No. 40003. This standard practice recognizes that as the distribution equipment used to~~

~~deliver power gets closer in proximity to the customer, the equipment varies based on the size of the customer. As such, the individual customer's load is what gives rise to the amount of costs incurred and determines the cost assignment. Nothing has changed in this regard. Accordingly, we approve the Company's allocation methodology for distribution plant.~~

~~**Subsidy/Excess Adjustment.** We find the Company's proposed method of distributing the rate increase approved herein in a manner to reduce current interclass subsidies by 5.1% is a reasonable step toward cost-based rates and strikes the appropriate balance between progress toward eliminating interclass subsidies and a recognition of the rate impacts on the various tariff classes. While the 5.1% subsidy/excess level only makes minor movement towards aligning revenues allocation with cost allocation; there is movement. This movement is guided by the concept of gradualism. The Industrial Group's proposed 50% subsidy/excess reduction would yield an approximate 25% revenue increase to the residential class. Therefore, we approve Petitioner's proposal~~ .

15. Rate Design.

a. HLF and LLF.

i. Petitioner's Evidence. Petitioner's witness Bailey supported the design of Rate LLF - Schedule for Low Load Factor Service ("Rate LLF"); and Rate HLF - Schedule for High Load Factor Service ("Rate HLF"). Mr. Bailey testified that the Company's rate design objectives for those rate schedules had not changed. Mr. Bailey described the customer charges and rate blocks for both rates. Mr. Bailey explained that the rates are designed to unbundle costs to provide more accurate price signals and reduce the inter-voltage subsidy and excess revenues.

Mr. Bailey testified that there are no proposed structural changes to Rate HLF or Rate LLF. However, the Company proposed changes to the Time of Use ("TOU") Riders, including changing the On-Peak and winter periods and eliminating the Rate Equalization Adjustment. Mr. Bailey stated that to the extent customers reduce their bills under the TOU Riders relative to their former standard bill, Duke Energy Indiana proposes to include the shifts to these rates in a migration adjustment. Mr. Bailey also testified that the Company also was proposing an Experimental Market Pricing Program and an Experimental Demand Management and Stability Program applicable to Rate LLF and Rate HLF.

ii. OUCC's Evidence. With respect to the Experimental Market Pricing Program and an Experimental Demand Management and Stability Program, OUCC witness Boerger recommended that the Company collect data on customers' behavior and study the effect of any behavioral changes on its costs of providing service, and be required to present this information and analysis at the time a request is made to extend or expand the programs.

iii. Intervenors' Evidence. Industrial Group witness Phillips recommended grandfathering customers on the existing TOU rate to avoid harsh impacts associated with the new rate design. Mr. Phillips further recommended expansion of the Market Pricing Program to allow up to 100 MW of load above what is known as the Customer Baseline Load. Mr. Phillips also suggested interruptions under the Demand Management and Stability Program allow for 24-hour notice.

Walmart witness Chriss recommended the Commission require Duke Energy Indiana to recover 100% of demand-related costs on the demand charge for the HLF rate schedules. Mr. Chriss testified that this recommendation is consistent with the stated purpose of HLF to serve high load factor customers and consistent with cost of service-based ratemaking.

Kroger witness Bieber likewise testified that the Company's rate design for Rate HLF secondary understates the demand charge while overstating the energy charge relative to the underlying cost components. Mr. Bieber stated that the Company's proposed Rate HLF secondary rate is designed to only recover 75% of demand-related fixed costs, while the energy charge would recover 155% of energy-related costs. Mr. Bieber recommended a rate design that will increase the demand-related charges while reducing the energy charges by a corresponding amount to recover Duke Energy Indiana's total proposed revenues for the Rate HLF schedule.

Mr. Bieber recommended that the Company's proposed migration adjustment should be allocated to the Rate LLF secondary schedule. Mr. Bieber stated that Rate LLF secondary already is a subsidized rate that shields customers from the impacts of demand charges, while Rate HLF secondary is a large subsidy provider.

iv. **Petitioner's Rebuttal Evidence**. Mr. Bailey disagreed with the recommendation of witnesses Chriss and Bieber that all demand related charges should be in the demand charge and energy costs in the energy charge. Mr. Bailey stated that rate design is a much more complex process. He stated that both witnesses, while supportive of cost based rate design, miss an important translation between cost of service and rate design. This occurs, he stated, by failing to recognize that all demands are not created equal. This failure to recognize differences in demand can result in a distortion of prices of a rate schedule. He explained that all demand elements from the cost allocation process are incorporated into rate design on a noncoincident basis. He noted that noncoincident demands for Rate HLF are approximately 25% higher than coincident demand, and about 19% higher than the class diversified demands. Accordingly, using noncoincident demands as a "common denominator" dilutes the other demand elements. He testified that the result of such dilution is that high load factor customers, who have higher coincidence with the system peak as load factor increases, can drive their costs below the actual cost of providing service. Given the practical need to design rates using such a "common denominator," he stated the rate designer's task is to design a rate that best mimics the cost of serving customers across a range of usage without all cost elements strictly defined by the rate structure. He explained that a common method to address the fact that noncoincident demands for HLF are relatively higher is to use what is called "tilting" – including some portion of demand costs in the energy charge. He testified that with this type of design, the higher load factor customers, as coincidence increases, are assigned some additional fixed costs that they are in fact imposing on the system through their consumption of energy. Mr. Bailey provided illustrative examples to demonstrate these concepts, including an illustration of the relationship between load factor and coincidence factor (a "Bary Curve") using actual load research from the Company's secondary Rate HLF customers. This evidence, he stated, shows that as load factor increases, system coincidence increases as well; and further, that if rates are not tilted, all customers would pay the same level of fixed costs irrespective of their coincident peak demands which cause the most expensive part of the system, (i.e., production and transmission). Such a non-tilted rate design, he stated, produces subsidies for the highest load factor customers, while the lowest load factor customers pay more than the cost to serve. He testified that a tilted rate, in contrast, minimizes the subsidies within the class, by shifting some of the demand costs to the energy portion of the rate. He summarized his testimony on this point by concluding that the intervenors' arguments are flawed, and a tilted rate structure is reasonable and appropriate. Mr. Bailey recommended that the Company's proposed structure, as modified by the Commission's final determination of revenue requirement, be approved.

Mr. Bailey did not oppose Mr. Bieber's proposal that the migration adjustment be allocated to the Rate LLF secondary schedule. Mr. Bailey noted that the class impacts of this recommendation are relatively small. Mr. Bailey stated that while Mr. Bieber's recommendation may precipitate additional migrations away from Rate LLF, he would expect this to be relatively small. Therefore, Mr. Bailey stated that the Company has no major objection to Mr. Bieber's recommendation.

Mr. Bailey disagreed with Mr. Phillips proposed expansion of the Market Pricing Program to allow up to 100 MW of load above the Customer Baseline Load, as well as his recommended 24-hour notice for the interruptible provisions of the Demand Management and Stability Program. Mr. Bailey indicated that Petitioner would agree to Dr. Boerger's recommendation that the Company collect data on customers' behavior and study the effect of any behavioral changes on costs of providing service, as well as be required to present this information and analysis at the time a request is made to extend or expand the programs.

Mr. Bailey also agreed with Mr. Phillips' recommendation to grandfather customers on the existing TOU rate. Mr. Bailey stated that Mr. Phillip's recommendation is reasonable. Mr. Bailey stated that these TOU rates are distinct line items in cost of service, and will be allocated their proportionate increase pursuant to final determination of the revenue requirement.

v. Commission Discussion and Findings.

(A) Design of Rates HLF and LLF. No party opposed Petitioner's proposed connection charges for Rates HLF and LLF or the declining block structure. However, both Walmart witness Chriss and Kroger witness Bieber recommended the Commission require Duke Energy Indiana to recover 100% of demand-related costs from the demand charge for the HLF rate schedules.

We are not persuaded that the change in rate design proposed by Walmart and Kroger is in the public interest. In particular, we are concerned about the impact this proposal will have on members of the rate class that have lower load factors. Mr. Bailey testified that making the changes proposed by Walmart and Kroger could actually drive the costs of high load factor customers below the cost of providing service.

Petitioner's proposed methodology for allocating demand avoids the potential for a disproportionate amount of cost being borne by low load factor customers, by taking into account the difference between "coincident" and "noncoincident" peak demand. "Coincident peak demand" is the demand of a customer (or a class of customers) at the time of the supplier's system peak demand. "Noncoincident demands" refers to a customer's (or a class of customers') peak demands regardless of when they occur. Noncoincident demands for Rate HLF are approximately 25% higher than coincident demand, and about 19% higher than the class diversified demands.

Treating coincident and noncoincident demand the same as proposed by Walmart and Kroger would result in more costs being unjustifiably borne by the lower load factor customers in the class. Accordingly, we find that Company's proposed structure for Rates HLF and LLF should be approved.

(B) HLF and LLF Experimental Rates. No parties opposed the experimental programs the Company proposed. However, Mr. Phillips suggested that they be modified. We find that Mr. Phillips' recommendation to modify the programs should be rejected. Mr. Phillips' recommendation that the Market Pricing Program be expanded to allow up to 100 MW of load above the Customer Baseline Load would shift additional financial risk to the Company. Mr. Phillips' recommendation that the Demand Management and Stability Program allow for 24-hour notice would not allow the Company to include load under as a curtailable resource under MISO requirements. Accordingly, we find that the Experimental Market Pricing Program and Experimental Demand Management and Stability Program should be approved as proposed.

Consistent with Dr. Boerger's recommendation and Petitioner's agreement thereto, we further find the Company should collect data on customers' behavior and study the effect of any behavioral changes on its costs of providing service. Petitioner shall present this information and analysis at the time a request is made to extend or expand the programs.

(C) Time of Use Rates. The Company proposed to modify the TOU Riders applicable to Rates HLF and LLF. The Company proposed to: (i) include the month of March in the Winter season because it presents similar characteristics as the traditional Winter month of December; and (ii) change the Winter On-Peak period to 6 a.m. to 2 p.m. and 6 p.m. to 9 p.m. Eastern Standard Time. In response to Industrial Group witness Phillips' concerns about the potential for harsh impacts associated with the new rate design on existing customers, the Company agreed to grandfather customers on the existing TOU rate. Subject to the foregoing agreement regarding existing customers, we find that Petitioner's changes to the TOU Riders applicable to Rates HLF and LLF, including grandfathering of existing TOU customers, should be approved.

(D) Rate Migrations. No party opposed Petitioner's proposed migration adjustment for expected the migration between the Rate HLF and Rate LLF secondary rate schedules. However, Kroger witness Bieber recommended that the migration adjustment be allocated to the Rate LLF secondary schedule. Mr. Bieber noted that Rate LLF secondary is already a subsidized rate that shields customers from the impacts of demand charges, while Rate HLF secondary is a large subsidy provider. Petitioner's witness Bailey agreed to Mr. Bieber's recommendation. Accordingly, we approve the proposed migration adjustment but direct Duke Energy Indiana to allocate the entire migration adjustment to the Rate LLF secondary schedule.

b. RS and CS.

i. Petitioner's Evidence. Petitioner's witness Bailey supported the design of Rate RS - Schedule for Residential and Farm Service ("Rate RS") and Rate CS - Schedule for Commercial Service ("Rate CS"). Mr. Bailey testified that Duke is proposing two rate design options relating to Rate RS and Rate CS. The Company's first, and preferred option, would apply if the Company were allowed to implement decoupling; its second option is without decoupling. Mr. Bailey stated that for the development of the two residential structures, the Connection Charges are $9.80 (with decoupling) and $10.54 (without decoupling), respectively, compared to the current charge of $9.01 per month. Mr. Bailey stated that for Rate CS, the Connection Charges are $9.27 (with decoupling) and $10.70 (without decoupling), respectively, compared to the current charge of $9.01 per month. Mr. Bailey also described the declining block structures for Rate RS and Rate CS. Finally, Mr. Bailey described three dynamic pricing pilot rates for both rate schedules.

ii. OUCC's Evidence. OUCC witness Watkins testified that a direct customer cost analysis approach is the proper methodology to be used to design customer charges. Under this approach, Mr. Watkins stated there is no provision to include corporate overhead expenses or any other indirect costs in the customer charge. Mr. Watkins stated that the Residential direct customer cost is calculated to be between $8.59 and $8.87 per month. Mr. Watkins explained that the lower cost of $8.59 is based on a 9.0% return on equity as recommended by OUCC witness David Garrett, while the higher cost of $8.87 is based on the Company's requested return on equity of 10.40%. Mr. Watkins stated that although his customer cost analysis indicates a customer charge of no more than $8.59 is warranted, he recommend the current Residential monthly customer charges of $9.01 for both Rate RS-General and Rate RS-High Efficiency be maintained.

Mr. Watkins noted that Mr. Bailey recommend reducing the discount in the second and third usage blocks under both of his rate design options (with and without decoupling). Mr. Watkins stated that in his opinion, this is a step in the right direction.

Mr. Watkins did not object to the proposed pilot rates. However, Mr. Watkins stated that if the pilots were approved, the Company should keep and maintain specific records on a customer by customer basis that compares each customer's actual bills (and billing determinants) to those that would have resulted under Rate RS. Furthermore, Mr. Watkins stated the Company should be required to submit detailed reports, data, and workpapers to the Commission, OUCC, and other interested parties on at least an annual basis concerning customer impacts and changes and in energy usage and peak load as a result of the critical peak pricing structure.

iii. Joint Intervenors' Evidence. Joint Intervenors witness Wallach testified that the Commission should reject the Company's proposal for the residential connection charge. Mr. Wallach stated that a $9.80 residential connection charge would recover $0.76, or about 8%, more than the actual cost to connect a residential customer. Mr. Wallach further testified that by the Company's own admission, a $10.54 residential connection charge would exceed the Company's (overstated) estimate of the cost to serve. Consequently, the Company's proposal for a $10.54 residential connection charge runs contrary to long-standing principles for designing cost based rates since it would inappropriately shift recovery of demand-related costs from the volumetric energy rate to the fixed connection charge. Mr. Wallach stated that a monthly connection charge of $9.01 would provide for the recovery of the cost of meters, service drops, and customer services required to connect a residential customer.

Mr. Wallach further stated that Company lacks a reasonable basis for continuing to employ a declining-block rate structure for residential energy rates. Mr. Wallach stated that the Company's declining-block rate structure would recover demand-related costs at a higher rate in the first energy block than in the second and third blocks, and thereby would further dampen energy price signals and promote inefficient customer behavior. In his cross-answering testimony, Mr. Wallach also recommended the Commission reject the Company's proposed block rate structure in either the with-RDM or without-RDM rate structure.

iv. Petitioner's Rebuttal Evidence. Mr. Bailey testified that the Company's declining rate block structure, is reasonable, appropriate and supported. Mr. Bailey stated that the design of Rate RS is supported by modeling. Mr. Bailey noted that the Company's proposal, without decoupling, represents an approximate across-the-board increase to the residential rates.

With respect to the dynamic pricing pilot programs, Mr. Bailey agreed Mr. Watkins' recommendation to "keep and maintain records on a customer by customer basis" is reasonable. However, Mr. Bailey noted that the current billing system does not support "shadow billing", which is billing under a rate other than the customer's selected rate. Mr. Bailey indicated that the Company can commit to tracking load impacts during pricing events and filing those with the Commission annually and on a schedule which would allow for the analysis of the data collected for a year of pricing events. Mr. Bailey stated that a three to six-month lag is appropriate to perform this type of analysis.

Petitioner's witness Diaz testified that the Company is also cognizant that retail customers do not want an increased fixed customer charge. Therefore, Ms. Diaz stated that the Company has stayed consistent with its most recent retail rate case of including meters and customer accounts in the fixed connection charge, and not expanding that charge to potentially include every distribution component necessary to provide service such as substations, wires, poles, etc. Ms. Diaz testified that the proposed fixed connection charge is cost-based and reflects fully embedded costs that include direct costs, overheads and uncollectible account costs, which represent the totality of costs to connect our customers to our system as defined by the Company in this proceeding.

v. Commission Discussion and Findings.

(A) Residential Connection Charges.

The Company proposes two different connection charges, or a fixed fee charged to each customer on their monthly bill regardless of the customer's energy usage during that month, depending on whether the Commission approves the Company's proposed Revenue Decoupling Mechanism ("RDM"). Specifically, in the event that the Commission approves the proposed RDM, DEI proposes to increase the residential connection charge from $9.01 to $9.80 per residential bill, representing a 9% increase over the current connection charge. Petitioner's Ex. 8, p. 7. However, if the Commission rejects the RDM proposal, DEI proposes to set the residential connection charge at $10.54 per residential bill, representing a 17% increase over the current connection charge of $9.01. *Id.*

For the with-RDM residential connection charge, according to Company Witness Bailey, DEI set it to recover costs classified as customer-related and allocated to the residential class in the Company's COSS. These costs include the costs for meters, service drops, metering and billing, other customer services, and bad debt. *Id.* at 6.

For the without-RDM residential connection charge, the Company has not explained how it derived this proposed rate, besides noting it is higher if the Company does not get its requested Revenue Decoupling Mechanism. However, because the without-RDM connection charge would be set at a higher rate than the with-RDM connection charge, the proposed without-RDM residential connection charge would recover costs that are classified as demand-related in the Company's COSS.

(1) Whether DEI's Proposals for the Residential Connection Charge Violates Principles of Cost-Based Rate Design

As the Commission recognized in IURC Cause No. 44576, the primary challenge in rate design is to reflect the costs that customers impose on the system, both to encourage them to use utility resources responsibly and to share costs fairly: "Cost recovery design alignment with cost causation principles sends efficient price signals to customers, allowing customers to make informed decisions regarding their consumption of the service being provided." IURC Final Order, Cause No. 44576, 72 (March 16, 2016). Accordingly, fixed connection charges should reflect the fact that each customer contributes equally to certain types of costs (e.g., meter costs) regardless of that customer's energy usage. Volumetric energy rates, on the other hand, recognize that customers of different sizes and load profiles contribute to other types of costs (e.g., generation plant costs) at different levels. According to the National Association of Regulatory Utility Commissioners ("NARUC"), if usage-driven costs are inappropriately collected through fixed connection charges, then customers will have reduced incentives to control their bills through conservation or investments in energy efficiency or distributed renewable generation. NARUC, *Distributed Energy Resources Rate Design and Compensation*, 118 (November 2016), available at https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0 (excerpt included as JI Ex. 1, Attachment JFW-6).

In order to provide efficient price signals, the Commission notes that volumetric energy rates should be set at levels that recover those categories of costs that tend to increase with customer usage over the long run, including plant, fuel, and O&M costs for the production, transmission, and distribution functions, along with certain customer-service costs that tend to vary with usage such as uncollectible costs (meaning the billed amounts not recovered from customers as a result of those customers' non-payment of all or a portion of their monthly bills). In other words, volumetric energy rates should reflect long-run marginal costs.

As James Bonbright explains in his seminal text Principles of Public Utility Rates:

> In view of the above-noted importance attached to existing utility rates as indicators of rates to be charged over a somewhat extended period in the future, one may argue with much force that the cost relationships to which rates should be adjusted are not those highly volatile relationships reflected by short-run marginal costs but rather those relatively stable relationships represented by long-run marginal costs. The advantages of the relatively stable and predictable rates in permitting consumers to make more rational long-run provisions for the use of utility services may well more than offset the admitted advantages of the more flexible rates that would be required in order to promote the best available use of the existing capacity of a utility plant…

> I conclude this chapter with the opinion, which would probably represent the majority position among economists, that, as setting a general basis of minimum public utility rates and of rate relationships, the more significant marginal or incremental costs are those of a relatively long-run variety – of a variety which treats even capital costs or "capacity costs" as variable costs.

James C. Bonbright, *Principles of Public Utility Rates*. Columbia University Press, 334, 336 (1961), available at media.terry.uga.edu/documents/exec_ed/bonbright/ principles_of_public_utility_rates.pdf (excerpts included as JI Ex. 1, Attachment JFW-7).

Almost three decades later, Alfred Kahn affirmed Bonbright's opinion in his text, The Economics of Regulation: ". . . the practically achievable benchmark for efficient pricing is more likely to be a type of average long-run incremental cost, computed for a large, expected incremental block of sales, instead of SRMC [short-run marginal cost]. . . ." Alfred E. Kahn, *The Economics of Regulation*, The MIT Press, 85 (1988) (excerpt included as JI Ex. 1, Attachment JFW-8).

In their text, *Public Utility Economics*, economists Paul Garfield and Wallace Lovejoy also describe which costs are truly customer-related and therefore appropriately recovered through the fixed connection charge:

> The purpose of both the connection charge and the minimum charge is to cover at least some of the costs incurred by the utility whether or not the customer uses energy in a particular month. For small customers under the block meter-rate schedule, a charge of this kind is intended to cover the expenses relating to meter service and maintenance, meter reading, accounting and collecting, return on the investment in meters and the service lines connecting the customer's premises to the distribution system, and others. Such expenses as these represent as a minimum the "readiness-to-serve" expenses incurred by the utility on behalf of each customer.

Paul J. Garfield and Wallace F. Lovejoy, *Public Utility Economics*, Prentice-Hall, Inc., 155-156 (1964) (excerpt included as JI Ex. 1, Attachment JFW-9).

Contrary to these principles, DEI proposes to recover through the with-RDM fixed connection charge not just customer connection costs—i.e., the costs for meters, service drops, and customer services—but also uncollectible costs. For the without-RDM residential connection charge, DEI proposes to recover both uncollectible costs and a portion of the costs classified as demand-related and allocated to the residential class under the Company's COSS in addition to minimum connection costs. We find that the Company's proposal to recover uncollectible costs through the residential connection charge is inconsistent with cost-based rate design, because uncollectible costs tend to vary with revenues and thus with usage. Thus, as discussed above, such costs are appropriately recovered through the volumetric energy rate.

We find it is also unreasonable for the Company to propose to recover demand-related cost through the fixed connection charge, as is the case in the without-RDM residential connection charge proposal. As discussed below, the Company's proposal to recover more than customer connection cost through the residential connection charge would give rise to cost subsidization within the residential class and would dampen energy price signals to consumers for controlling their bills through conservation or investments in energy efficiency or distributed renewable generation.

JI Witness Wallach estimated a residential cost of connection of $9.04 per residential per bill by simply removing the uncollectible costs from the Company's COSS allocation to the residential class of about $88.4 million in customer-related costs, then dividing the net amount of $81.06 million by the number of residential bills yields a connection cost of $9.04 per residential bill. JI Ex. 1, pp. 26–27; *see also* JI Ex. 1, Attachments JFW-10, and Petitioner's Exhibit 7-H (MTD), Schedule 1.

$0.76 of the $1.50 difference between JI Witness Wallach's $9.04 customer connection cost and the $10.54 without-RDM connection charge proposed by DEI represents the load-varying uncollectible costs that should be recovered through volumetric energy rates. The remaining $0.74 difference represents costs classified as demand-related in the Company's COSS that would be recovered through the fixed connection charge under the Company's without-RDM proposal. As discussed below, this shift in recovery of load-varying and demand-related costs from the volumetric energy rate to the fixed connection charge would give rise to cost subsidization within the residential class and would dampen energy price signals to consumers for controlling their bills through conservation or investments in energy efficiency or distributed renewable generation.

(2) Whether DEI's Proposal for the Residential Connection Charge Would Lead to Intra-Class Cost Subsidization

As discussed above, DEI's proposal to increase the residential connection charge in the without-RDM scenario would shift recovery of both load-varying and demand-related costs from the volumetric energy rate to the fixed connection charge. Such load-varying or demand-related costs are driven by residential load and are therefore appropriately recovered from residential customers in proportion to their contribution to total load. To the extent that load-varying or demand-related costs are recovered at a fixed rate through the residential connection charge rather than at a volumetric rate through the energy charge, residential customers with below-average usage would bear a disproportionate share of demand-related costs and consequently subsidize customers with above-average usage. In this case, a residential customer with below-average usage will pay more, and a residential customer with above-average usage will pay less, than their fair share of such costs.

As explained above, the $1.50 difference between customer connection cost and the without-RDM residential connection charge proposed by DEI represents load-varying or demand-related costs that would be inappropriately recovered from each residential customer every month through a fixed charge on the customer's bill. DEI estimates about 9.0 million residential bills in the test year. This means that about $13.5 million of load-varying or demand-related costs would be recovered annually through the residential fixed connection charge under the Company's proposal for the without-RDM scenario.[40]

[40] The $13.5 million result is derived by taking the product of the annual number of residential bills (9.0 million) and the amount of load-varying or demand-related costs that would be recovered through the proposed without-RDM residential connection charge ($1.50 per bill).

If the load-varying and demand-related costs recovered through the residential fixed connection charge under the Company's proposal for the without-RDM scenario were instead recovered through the volumetric energy rate as proposed by Joint Intervenors, each residential customer would contribute to recovery of these costs in proportion to their usage. The Company estimates residential sales in the test year of about 8.7 million megawatt-hours. Petitioner's Exhibit 7-H (MTD), Schedule 1. Therefore, if the $13.5 million of load-varying or demand-related costs continued to be recovered through the volumetric energy rate rather than through the fixed connection charge, they would be charged at a rate of 0.16 cents per kilowatt-hour ("¢/kWh").[41] In this case, a residential customer with below-average monthly usage of 500 kWh would contribute about $9 per year toward recovery of the $13.5 million of load-varying or demand-related costs while a customer with above-average monthly usage of 1,500 kWh would contribute about $28 per year.[42] Thus, under Joint Intervenors' proposal, the 1,500 kWh customer would contribute three times more than the 500 kWh customer, in direct proportion to their usage and consistent with accepted principles of cost-causation.

In contrast, under the Company's proposal to recover $13.5 million of load-varying and demand-related costs through the fixed connection charge, each residential customer would contribute $18 per year toward recovery of such costs regardless of that customer's usage. A below-average 500 kWh customer would therefore pay almost double their fair share of these load-varying and demand-related costs under the Company's proposal while an above-average 1,500 kWh customer would pay less than two-thirds of their fair share. We find the Company's proposal in this regard to be unjust and unreasonable.

(3) Whether DEI's Proposal for the Residential Connection Charge Would Dampen Energy Price Signals

DEI proposes to set the without-RDM residential connection charge at a rate that greatly exceeds the cost to connect a residential customer. The amount in excess of the customer connection cost represents usage-related costs that are more appropriately recovered in the volumetric energy rate. However, under the Company's proposal, this excess over the customer connection cost would instead be inappropriately recovered through the fixed connection charge. This shift in the recovery of usage-related costs from the volumetric energy rate to the fixed connection charge would dampen price signals and discourage economically efficient behavior by residential customers.

With a fixed amount of revenue requirements to be recovered from the residential class, the higher the residential fixed connection charge, the lower the volumetric energy rate, and vice versa. With the residential fixed connection charge set at $10.54 in the without-RDM proposal, DEI proposes an average volumetric energy rate (average across the three proposed energy blocks) of 12.51¢/kWh in order to recover the proposed allocation of test year revenue requirements to residential customers. See data provided in Duke's 1-5-16(a)(2) Workpaper 2_RS Rate Design Summary.XLSM'. If, instead, the fixed connection charge were set at the cost-based rate of $9.04,

[41] The 0.16¢/kWh result is derived by dividing $13.5 million by residential sales of 8.7 million megawatt-hours.
[42] Based on data provided in Schedule 1 of Petitioner's Exhibit 7-H (MTD), estimated monthly usage is about 960 kWh for an average residential customer.

JI Witness Wallach estimates that the average volumetric energy rate would have to be increased to 12.67¢/kWh to recover the same allocated revenue requirement.

In other words, DEI is proposing an average residential energy rate for the without-RDM scenario that is 0.16¢/kWh, or about 1.2%, less than what the volumetric rate would be if the residential fixed connection charge were set at the cost-based rate of \$9.04. Thus, the Company's proposal for the without-RDM residential connection charge would dampen the price signal provided by the volumetric energy rate by about 1.2%.[43]

Since the volumetric energy rate under the Company's proposals for the residential connection charge would be lower than the volumetric energy rate with a cost-based fixed connection charge of \$9.04, we would expect residential customers to consume more energy with the Company's proposed connection charges than they would with a cost-based connection charge, which is unacceptable. The magnitude of the increase in energy consumption would depend on: (1) the extent to which the volumetric energy rate with the Company's proposed residential connection charge is lower than the volumetric energy rate with a cost-based connection charge, and (2) the price elasticity of electricity demand.

It is true that residential customers respond to the price incentives created by the electrical rate structure. Those responses are generally measured as price elasticities, i.e., the ratio of the percentage change in consumption to the percentage change in price. Price elasticities are generally low in the short term and rise over several years, because customers have more options for increasing or reducing energy usage in the medium to long term. For example, a review by Espey and Espey (2004) of 36 articles on residential electricity demand published between 1971 and 2000 reports short-run elasticity estimates of about −0.35 on average across studies and long-run elasticity estimates of about −0.85 on average across studies. JI Ex. 1, Attachment JFW-11. In other words, on average across these studies, consumption decreased by 0.35% in the short term and by 0.85% in the long term for every 1% increase in price.

JI Witness Wallach provided a summary of marginal-price elasticities over the last forty years, which typically examine the change in usage as a function of changes in the marginal rate paid by the customer. Based off that survey of studies, JI Witness Wallach found that –0.3 would be a reasonable mid-range estimate of the impact over a few years. If the residential connection charge were increased as proposed by DEI for the without-RDM scenario, the volumetric energy rate would be about 1.2% less than what the volumetric energy rate would be if the residential connection charge were set at the cost-based rate of \$9.04. Assuming an elasticity of –0.3, this 1.2% reduction in the volumetric energy rate would result in an increase in energy consumption of about 0.4% for the average residential customer. This means that all else equal, residential load after a few years with a residential connection charge as proposed by DEI under the without-RDM scenario would be expected to be about 0.4% higher than it would have been if the residential connection charge had been set at the cost-based rate of \$9.04.

[43] To be precise, the Company's proposal for the residential connection charge would dampen price signals by about 1.2% if DEI were proposing a flat energy rate. The Company's proposal to maintain a declining-block rate structure would even further dampen price signals.

(4) Conclusion

The Commission rejects both of the Company's proposals for setting the residential connection charge. A $9.80 residential connection charge would recover $0.76, or about 8%, more than the actual cost to connect a residential customer. In other words, the Company's estimate of residential connection cost overstates the actual cost to serve by about 8%. On the other hand, by the Company's own admission, a $10.54 residential connection charge would exceed the Company's (overstated) estimate of the cost to serve. Consequently, the Company's proposal for a $10.54 residential connection charge runs contrary to long-standing principles for designing cost-based rates since it would inappropriately shift recovery of load-related costs from the volumetric energy rate to the fixed connection charge. The Company's proposal to recover load-related costs through the residential connection charge would dampen price signals to consumers for reducing energy usage, disproportionately and inequitably increase bills for the Company's smallest residential customers, and result in subsidization of larger residential customers' costs by customers with below-average usage.

Instead, the Commission finds that the residential connection charge should be maintained at the current rate of $9.01 per residential bill, reflecting the actual cost to connect a residential customer. Consistent with long-standing cost-causation and rate-design principles, a monthly connection charge of $9.01 provides for the recovery of the cost of meters, service drops, and customer services required to connect a residential customer. ~~Both Joint Intervenors and OUCC opposed Petitioner's proposed increase to the customer charge from $9.01 to $9.80 (with decoupling) and $10.70 (without decoupling). In reviewing the reasonableness of Petitioner's proposed residential connection charge, it is important to examine connection/customer charges approved for other electric utilities in the State. In *Re Indianapolis Power & Light Co* ("IPL 2016 Rate Order"), we approved increases in IPL's customer charges from $6.70 to $11.25 (for less than 325 kWh/month) and $11.00 to $17.00 (for greater than 325 kWh/month). Cause No. 44576, 2016 WL 1118795, at *76 (IURC March 16, 2016) *order corrected*, 2016 WL 1179961 (IURC March 23, 2016). In the IPL 2016 Rate Order, we noted the increase in the customer charge was a "move toward a more fixed and variable rate design consistent with traditional cost causation principles," while being "demonstrably short of SFV rates." The Court of Appeals affirmed the IPL 2016 Rate Order in *Citizens Action Coalition of Indiana, Inc. v. Indianapolis Power & Light Company*, 74 N.E.3d 554, 555 (Ind. Ct. App. 2017).~~

~~Subsequent to issuing the IPL 2016 Rate Order, we approved a settlement in NIPSCO's base rate case ("NIPSCO 2016 Rate Order") which increased the monthly customer charge from $11.00 to $14.00 for NIPSCO's residential customers. In approving the customer charge increase included in the settlement in that case, we again noted "the increase to the customer charge was a move toward a more fixed variable design consistent with traditional cost causation principles, while being demonstrably short of straight fixed variable rates." (NIPSCO 2016 Rate Order at 88). Again, Joint Intervenors appealed the Order and challenged the increase in fixed monthly charges, but the Court of Appeals affirmed the approval of the NIPSCO settlement in all respects. *See Citizens Action Coalition v. Northern Indiana Public Service Co.*, 2017 WL 1399850 (Ind. App. 2017).~~

~~Against this backdrop, we decline to find that Petitioner's modest increase in the residential connection charge would inappropriately shift recovery of demand-related costs from the volumetric energy rate to the fixed connection charge as suggested by the Joint Intervenors. To the contrary, the evidence of record reflects that the proposed fixed connection charges are cost-based and reflect embedded costs of connecting customers to Petitioner's system. Accordingly, we approve Petitioner's proposed increase to the fixed charges. Because we approve Petitioner's decoupling proposal as discussed below, we find that the fixed connection charges for Rate RS and Rate CS should be $9.80 and $9.27, respectively~~ .

(B) Residential Declining Block Rates.

The Company's residential energy rates currently employ a "declining-block" rate structure. Under a declining-block rate structure, a customer pays a higher volumetric rate for usage up to a certain threshold amount (i.e., a "block" of usage) than for usage that exceeds that threshold. The Company's current residential energy rate uses three energy blocks: (1) for monthly usage up to 300 kWh; (2) for monthly usage between 301 and 1,000 kWh; and (3) for monthly usage in excess of 1,000 kWh. Residential customers currently pay a rate of: (1) 8.91¢/kWh for monthly usage up to 300 kWh; (2) 5.19¢/kWh (a 42% discount from the first-block rate) for monthly usage in excess of 300kWh but up to 1,000 kWh; and (3) 4.26¢/kWh (an 18% discount from the second-block rate and a 48% discount from the first-block rate) for monthly usage in excess of 1,000 kWh.[44]

The Company proposes two different declining-block rate structures for residential energy rates depending on whether the Commission approves the proposed Revenue Decoupling Mechanism ("RDM"). In both cases, DEI proposes to continue employing three energy blocks. For the without-RDM block energy rates, DEI proposes to reduce the discounts between the first and second block rates and between the second and third block rates compared to the current block rate discounts. For the with-RDM block energy rates, the Company proposes to narrow the spread between block rates even further.

Current and DEI Proposed Residential Energy Rates

	Current (¢/kWh)	Discount from First Block	Proposed without RDM (¢/kWh)	Discount from First Block	Proposed with RDM (¢/kWh)	Discount from First Block
Up to 300 kWh	8.91		16.09		15.09	
301-1,000 kWh	5.19	41.7%	11.71	27.2%	12.23	18.9%
Over 1,000 kWh	4.26	52.2%	10.61	34.0%	11.03	26.9%

According to DEI Witness Bailey, the Company is proposing a major revision to the current rate design because the current design no longer reflects the Company's cost structure: "The current structure of Rate RS includes a significant declining block structure that by itself would be difficult to justify today." Petitioner's Revised Ex. 8, p. 4, lines 18–20. According to Mr. Bailey,

[44] For residential customers taking service under Contract Rider No. 6.3 (Optional High Efficiency Residential Service), the third-block rate of 4.26¢/kWh applies solely in the months July through October. For all other months, the third-block rate is 3.62¢/kWh.

the block rate structure proposed for the with-RDM scenario was designed to reflect the Company's average embedded cost curves. Specifically, the proposed block discounts for the with-RDM energy rates are set to mimic the Company's estimate of the decline in residential non-customer-related test-year revenue requirement per kWh as usage increases. In contrast, DEI did not design the proposed without-RDM block rate structure based on its average embedded cost curves. Instead, the without-RDM block rate structure was designed to provide a "modest reduction in risk to the Company" relative to the proposed with-RDM block rate structure. *Id.* at 5, lines 16–17.

The Commission rejects the Company's proposal for without-RDM rates. Regardless of whether the Commission would have approved the Company's RDM proposal, it would not be appropriate to deviate from cost in the design of residential energy rates solely for the purpose of providing a "modest reduction in risk to the Company."

The Commission also rejects the Company's proposed with-RDM rate structure for residential energy rates. Whether viewed from a long-run price efficiency perspective or short-run cost-causation price perspective, the Company's proposed with-RDM rate structure is not cost-based. From a long-run price efficiency perspective, the with-RDM rate structure should be designed to reflect marginal, not average, embedded costs. A marginal cost design would likely support a flat, if not inclining, rate structure for the Company's residential energy rates. Even from a short-run cost-causation perspective, the proposed with-RDM rate structure is not cost-based because the Company's average embedded cost curves, which serve as the basis for the proposed rate structure, are derived from a flawed cost of service study that misallocates costs to the residential class. JI Witness Wallach developed an average cost-based block rate structure for residential energy rates based on his re-estimation of the Company's average cost curves. JI Ex. 5 at 17, lines 4–6. In response to JIs' discovery, DEI modified its cost of service study to correct for the misallocations JI Witness Wallach had identified, which he then used the results of this corrected COSS to re-estimate the Company's average cost curves. See JI Ex. 5, Attachments JFW-1 and -2; see also JI Ex. 5 Public Workpapers 2 (Attachment CAC 12.8-A) and 3 (Corrected Attachment CAC 12.8-A). Using his re-estimation of the Company's average cost curves, Mr. Wallach mimicked the Company's procedures for developing a block rate structure based on the average cost curves by modifying the spreadsheet relied on by DEI to develop its proposed with-RDM rate structure, as provided in DEI Response to CAC Data Request 12.13 and corresponding Attachment CAC 12.13-A (Attachment JFW-3). See JI Ex. 5 Public Workpapers 1 and 4 (Corrected Attachment 12.13). As indicated in the following table, an average cost-based block rate structure is substantially flatter than that proposed by DEI for the with-RDM scenario.

DEI Proposed and Average Cost-Based Block Rate Structure

	Discount from First Block	
	DEI Proposed	**Average Cost-Based**
Second Block	18.9%	6.7%
Third Block	26.9%	9.9%

As DEI acknowledges, the residential energy rate structure must be substantially modified to bring it in line with the Company's cost structure. The Company's proposal for the with-RDM declining-block rate structure represents a move in the right direction. However, it does not go far enough. Accordingly, we reject both the with-RDM and without-RDM rate structures proposed by DEI regardless of the Commission's ruling on the proposed RDM. The declining-block rate structures proposed by DEI in either the with-RDM or without RDM scenarios would inappropriately recover more costs in the first energy block (and less costs in the second and third blocks) than is justified either on a long-run marginal or short-run average embedded cost basis, and thereby would dampen energy price signals and promote inefficient customer behavior.

Instead, the Commission orders that the Company should aim to eliminate the declining-block rate structure in order to more reasonably reflect long-run marginal costs and to remove incentives for increased usage. However, in the interests of gradualism, we order that DEI set the block energy rates at a level that, in combination with the $9.01 fixed connection charge that: (1) recovers the Commission-authorized allocation of base revenues to the residential class; and (2) provides no more than a 15% price discount from the first block to the third block energy rate. We order the Company to submit a compliance filing consistent with the findings in this section. Other parties will have 30 days to respond to Duke's compliance filing for the Commission's consideration.

~~OUCC witness Watkins testified that Petitioner's declining block rate structure is a step in the right direction and recommended it be approved. Joint Intervenor witness Wallach, however, testified that Company lacks a reasonable basis for continuing to employ a declining-block rate structure for residential energy rates and supports a flat volumetric energy charge~~.

~~The record shows the Company's proposal is more cost-justified than one that collects demand-related costs through a flat volumetric energy charge. Mr. Bailey testified that the design of Rate RS is supported by modeling, which was provided to the parties in this Cause. We further note that in the IPL 2016 Rate Order, we found that replacing declining block energy rates with inclining block rates could result in harm to customers that use an above average amount of energy. *Re Indianapolis Power & Light Co.*, Cause No. 44576, at 72. We find Petitioner's proposed continuation of the declining block rates should be approved. Additionally, because we approve the Company's decoupling proposal as discussed below, we also approve the Company's rate design associated with it, which provides for less steeply declining block rates~~ .

~~(A)~~(C) **Dynamic Pricing Pilots.** The Company proposed three unique rate designs for each of Rates RS and CS: (i) Schedule CPP: Critical Peak Pricing; (ii) Schedule VPP: Variable Peak Pricing; and (iii) Schedule VPP-D: Variable Peak Pricing with Demand. No party opposed any of the three optional rate designs. The OUCC, however, proposed certain reporting and record keeping requirements which the Company agreed to comply with. Based on the evidence presented by Petitioner in support of the dynamic pricing rate designs we find that they should be approved subject to Petitioner's complying with the recordkeeping and reporting requirements in the manner described by Mr. Bailey.

c. Revenue Decoupling Mechanism.

i. Petitioner's Direct Evidence. Petitioner's witness Hansen supported Petitioner's proposed five-year revenue decoupling mechanism ("RDM") proposal. Mr. Hansen stated that the RDM is intended to complement Duke Energy Indiana's proposed dynamic pricing pilots, potential retail rate design changes, energy efficiency programs, the Company's current volt/VAR optimization project, and address other external changes contributing to reductions in electricity usage by residential and small commercial customers. Mr. Hansen stated that for residential and small commercial customers, the RDM would make the Company indifferent to the effects of customer response to dynamic pricing pilots, modifications to the current default rate designs, implementation of volt/VAR optimization, and successful implementation of energy efficiency programs.

Mr. Hansen stated the RDM would include a deferral tracking account in which the difference between allowed and actual revenue toward fixed cost recovery would be recorded. Mr. Hansen stated that over-recovery of allowed fixed-cost revenue (when RDM allowed fixed-cost revenue is lower than actual fixed-cost revenue) would result in a rate decrease in a future period. Conversely, Mr. Hansen testified that under-recovery of allowed fixed-cost revenue (when RDM allowed fixed-cost revenue is higher than actual fixed-cost revenue) would result in a rate increase in a future period. Mr. Hansen noted that the RDM would completely replace the recovery of lost revenues in the Company's EE Rider for residential and small commercial customers.

ii. <u>OUCC's Evidence</u>. OUCC witness Dr. David E. Dismukes, PhD testified that the Company's RDM proposal should be rejected for a number of reasons. First, Dr. Dismukes stated that the Company's proposed RDM is inconsistent with the Commission's past policies regarding decoupling mechanisms for electric utilities and the Sales Reconciliation Component ("SRC") approved for natural gas utilities.

In addition, Dr. Dismukes testified that the Company did not show that its efficiency activities or proposed rate design changes have, or will have, a negative financial impact on its ability to earn its allowed rate of return. Dr. Dismukes noted that on a historical basis, the Company's past efficiency efforts have not significantly impacted its ability to earn its allowed return on equity ("ROE"), particularly because the Company already has a mechanism in place that allows it to recover lost revenues associated with these activities. Dr. Dismukes stated that the Company has not provided any projections that quantify any specific future earnings challenges, raising questions about its validity and whether or not the Company will, in fact, see financial impacts that differ significantly from those experienced over the past five years.

Lastly, Dr. Dismukes stated that the Indiana Code already provides that lost revenues associated with energy efficiency ("EE") and demand side management ("DSM") activities can be recovered through a lost revenue adjustment mechanism ("LRAM"). Dr. Dismukes testified that the Company has taken advantage of this opportunity and, as a result, does not have any disincentive to promote EE or DSM measures. Dr. Dismukes stated that the Company does not expect revenue losses from its dynamic pricing pilot programs to be significant and, in regard to its volt/VAR optimization program, its cost benefit analysis showed the overall program resulted in a net benefit. Therefore, Dr. Dismukes concluded that the Company's proposed RDM is not needed to address the Company's purported concerns.

iii. <u>Petitioner's Rebuttal Evidence</u>. Mr. Hansen testified that Company's proposed RDM is consistent with decoupling mechanisms the Commission has previously approved. Mr. Hansen stated that the only electric-utility-specific concern expressed by the Commission in its rejection of Vectren South Electric's decoupling mechanism was based on a misunderstanding of how decoupling affects individual customers. In addition, Mr. Hansen noted that the Vectren South Electric Order specifically acknowledged that the introduction of "creative rate designs" (in the manner the Company has proposed) could affect how the Commission views decoupling for an electric utility. Mr. Hansen testified that the RDM is a better and more comprehensive mechanism than the LRAM and will allow the Company to improve its customers' incentives and ability to manage their usage and bills.

Mr. Hansen further testified that implementing the RDM would put the Company in a position to plan more significant changes to rates in the future without factoring lost fixed cost recovery into its policy evaluations. While the dynamic pricing pilot is limited in scope, Mr. Hansen testified it could lead to the Company offering one or more voluntary rates that obtain significant participation in the future. While the cost-benefit analysis reflects overall benefits from implementing the volt/VAR program, Mr. Hansen stated that those benefits do not necessarily represent financial gains that accrue to the Company or its shareholders.

Mr. Hansen noted that he modified the Company's proposal to add a four percent cap on annual RDM rate increases with no floor on rate decreases.

iv. Joint Intervenors' Cross-Answering Testimony. Mr. Wallach agree with Dr. Dismukes' recommendation that the Commission reject the Company's request to implement the proposed RDM.

v. Commission Discussion and Findings.

As it applies to the residential class, Duke's proposed Revenue Decoupling Mechanism ("RDM") would allow for recovery of the difference between an "allowed" amount of demand-related revenues (so-called "fixed" revenues) and the actual amount of demand-related revenues. Any positive or negative difference between allowed and actual fixed revenues in the year would be deferred and recovered from or credited to residential customers, respectively, in the following year. In each year of the proposed five-year implementation period, the *allowed* amount of fixed revenues would be calculated as the product of: (1) actual number of residential customers; and (2) allowed fixed revenue per customer ("FRC"). The allowed FRC would be derived as the ratio of: (1) 2020 test-year demand-related costs allocated to the residential class; and (2) 2020 test-year number of customers. While the allowed FRC would remain constant over the five-year implementation period, the allowed amount of fixed revenues would vary with the actual number of customers.

Under Duke's proposed RDM, the *actual* amount of fixed revenues in each year would be calculated as the product of: (1) actual residential sales; and (2) the Fixed Energy Charge ("FEC"). The FEC would be derived as the ratio of: (1) 2020 test-year demand-related costs allocated to the residential class; and (2) 2020 test-year residential sales. The FEC therefore represents the per-kWh rate at which residential demand-related costs are recovered through volumetric energy charges. As with the calculation of allowed fixed revenues, while the FEC would remain constant over the five-year implementation period, the actual amount of fixed revenues would vary with actual sales. See Petitioner's Ex. 7-H (MTD).

DEI is proposing the RDM as a way to "decouple" recovery of fixed revenues from residential sales. In the absence of decoupling, the amount of fixed revenues recovered from residential customers would be determined by the volume of residential sales (i.e., by the product of the FEC and residential sales). In contrast, with the proposed RDM, the amount of fixed revenues recovered from residential customers would effectively be set at the product of the FRC and the number of residential customers, regardless of residential sales volumes.[45]

DEI is proposing to decouple fixed revenue recovery from residential sales through the RDM because, according to Company witnesses Davey and Bailey, the Company is primarily concerned that, because of declining customer usage and resulting slow sales growth, residential fixed revenues currently recovered through energy rates will not keep pace with the escalation in fixed costs incurred by DEI over time. Petitioner's Ex. 2, pp. 26-27, Petitioner's Ex. 8, pp. 24-25. Mr. Davey further asserts that this growing gap between fixed costs and fixed revenues, and the resulting erosion in shareholder earnings, would necessitate "more frequent base rate cases." Petitioner's Ex. 2, p. 26. In contrast, as Mr. Davey sees it, the proposed RDM would allow residential fixed revenues to keep pace with fixed-cost escalation by growing allowed fixed revenues with growth in the number of residential customers. According to Mr. Davey, by allowing fixed revenues to increase with customer growth, the proposed RDM would reduce the frequency of base rate cases. *See* JI Ex. 5, Attachment JFW-4. In addition, Mr. Davey notes that residential fixed revenues would be less volatile if such revenues were driven by customer growth (per the proposed RDM) than by sales growth (as is currently the case). Petitioner's Ex. 2, p. 27.

We find that DEI lacks a reasonable basis for its proposal to implement a revenue per customer decoupling mechanism for residential and small-commercial customers. DEI failed to offer any evidence regarding the expected growth in fixed costs or the extent to which residential fixed revenues would fall short of fixed costs if such revenues continued to grow with residential sales. DEI has failed to show that it would suffer financial harm if the Commission were to reject the Company's proposal or that customers would benefit from more stable bills if the Commission were to approve the Company's proposal. While the Company's shareholders may not suffer harm if the proposed RDM is rejected by the Commission, the same cannot be said for the Company's residential customers if the proposed RDM would have been approved. To the contrary, residential customers would be expected to pay more for electric service with than without the proposed RDM without receiving any tangible economic benefit in return.

The proposed RDM would be expected to not only ensure, but also *enhance* revenue recovery for DEI and its shareholders between rate cases. Fixed revenues recovered from residential customers would increase over time with growth in customer count under the proposed RDM rather than with growth in energy sales under current ratemaking practice. The Company currently forecasts residential customer count to grow at a faster pace than residential energy sales over the proposed five-year RDM implementation period. Consequently, fixed revenue recovery under the proposed RDM is expected to exceed that under current ratemaking practice over the five-year implementation period. Specifically, over the proposed five-year RDM implementation period, DEI currently forecasts an average annual growth rate of 0.85% for number of residential

[45]With the proposed RDM, the actual amount of fixed revenues recovered from residential customers in any year will still be determined by the product of the FEC and residential sales in that year. However, any differences between actual fixed revenue recovery through energy rates (as driven by actual sales volume) and allowed fixed revenue recovery (as driven by actual number of customers in that year) will be reconciled in the following year.

customers and 0.11% for residential energy sales. JI Ex. 5, Attachment JFW-5. Based on those growth rates, estimated residential fixed revenue recovery under the proposed RDM would exceed that under current ratemaking practice by about $56 million over the five-year implementation period. JI Ex. 5, p. 23; see also JI Ex. 5 Public Workpaper 1. As OUCC Witness Dismukes notes, the proposed RDM would benefit the Company's shareholders with revenue stability, but not the Company's customers with bill stability. Public Ex. 10, p. 18. Likewise, according to Company Witness Hevert, while the proposed RDM offers shareholders reduced earnings risk, it would not offer customers the benefit of a reduction in the Company's cost of equity. JI Ex.5, Attachment JFW-6 (Duke Response to CAC Data Request 16.12(c)). And although the proposed RDM would eliminate revenue erosion between rate cases resulting from a decline in residential usage, according to OUCC Witness Dismukes, the Company has not committed to increase its spending on energy efficiency programs. Public Ex. 10, pp. 29-30; *see also* Tr. A-60, line 21–A-61, line 1 (Q "But, again, we don't have a concrete plan or any commitment from the company that more energy efficiency will be secured by Duke receiving authority to implement decoupling; is that correct? Yes or no, please." A "No, not at this time."). Nor has DEI committed to a specific length of time before filing its next base rate case, despite the Company's claim that the proposed RDM would reduce the frequency of such filings.[46] JI Ex. 5, Attachment JFW-4; Tr. A-61, lines 13–15 (Q "But just a plan for rate cases. Do we have a plan?" A "We have no plan for future rate cases.").

Thus, the Commission hereby rejects Duke's request for decoupling. The proposed RDM would not provide any tangible economic benefits to residential customers. To the contrary, over the proposed five-year RDM implementation period, residential customers would be expected to pay more for electric service with than without the RDM. In other words, the proposed RDM would be expected to not only ensure, but also enhance revenue recovery for DEI and its shareholders between rate cases. The Commission cannot approve such a design.

~~We have approved revenue decoupling for natural gas utilities since 2006 when we initially approved a Sales Reconciliation Component ("SRC") decoupling mechanism for Vectren Energy in Consolidated Cause Nos. 42943 and 43046 (Order approved December 1,2006). In that case, we found: "volumetric pricing makes it difficult for an Indiana gas utility to earn its authorized return because usage per customer is declining. Under these conditions, this form of usage-based rate design has become an asymmetrical risk for the utilities." *Re Petition of Indiana Gas Company, Inc. and Southern Indiana Gas and Electric Company*, Cause No. 42934 and 43046 (Dec. 1, 2006) at 39~~.

~~In 2007, we approved a similar SRC for Citizens Gas. *Order on Rehearing*, Cause No. 42767 (August 29, 2007). In 2011, we approved an SRC decoupling mechanism for Citizens Gas of Westfield in Cause No. 43624 (March 10, 2010). Since that time, the Commission has authorized the following natural gas utilities to implement mechanisms similar SRCs: Indiana Utilities Corporation (Cause No. 44062, September 5, 2012), as well as Midwest Natural Gas Corporation, South Eastern Indiana Natural Gas Company, Inc., Fountaintown Gas Company, Inc., Community Natural Gas Company, Inc., Boonville Natural Gas Corporation, Indiana Natural Gas Corporation, and Switzerland County Natural Gas Company, Inc. (Cause No. 43995, November~~

[46] On the other hand, in retrospect, residential customers may not have benefitted from the extended duration between the previous and current rate cases given OUCC witness Lane Kollen's finding that DEI is currently over-earning. *See Verified Direct Testimony of Lane Kollen on behalf of the Indiana Office of Utility Consumer Counsel*, Cause No. 45253, 3-4 (October 30, 2019).

~~30, 2011). In addition to the foregoing cases approving SRCs, in our December 2006 Order initiating an investigation into rate design alternatives and energy efficiency measures for natural gas utilities, we expressed our anticipation that "decoupling mechanisms will be an important element in promoting utility stability and benefits to customers."~~ ~~*In re the Investigation on the Commission's Own Motion into Rate Design Alternatives and Energy Efficiency Measures for Natural Gas Utilities,*~~ ~~Cause No. 43180 (Dec. 1, 2006).~~

~~In this case, the Petitioner has presented evidence similar to that presented by gas utilities in the State. Customer conservation and declining usage impede an electric utility's ability to earn their authorized return. Said another way, the financial health of electric utilities is tied directly to retail sales, because their fixed costs are recovered through charges based on how much customers use. Decoupling helps keep electric utilities "whole" when their customers are saving energy. Decoupling also promotes electric utility stability when usage declines for other reasons, such as customer-owned generation.~~

~~The Company's proposed RDM is structured similarly to the SRCs we have previously approved, in that it compares actual revenue (referred to as "margin" in the tariff) to allowed revenue that is adjusted for the number of customers currently served. As with the SRCs, the proposed RDM would pass cumulative deferrals through to rates once per year. In addition, in rebuttal, Petitioner modified its proposal to add a four percent cap on annual RDM rate increases with no floor on rate decreases, which is similar to the caps in place on the Vectren Energy and Citizens Gas SRC decoupling mechanism. Accordingly, the RDM is similar in concept and structure to the SRCs we have previously approved for natural gas utilities in Indiana.~~

~~The OUCC notes that to date, this Commission has not approved a decoupling mechanism for an electric utility. However, revenue decoupling for electric utilities is not a novel concept. As indicated by Petitioner's witness Hansen revenue decoupling mechanisms have been approved by state public utility commissions for a number of fully integrated electric utilities. Electric utilities that have approved decoupling mechanisms include (with the state or states in which a mechanism has been approved in parentheses): Avista Utilities (Idaho and Washington), Hawaiian Electric Company (Hawaii), Idaho Power Company (Idaho), Pacific Gas and Electric Company (PG&E, in California), Pacific Power (Washington), Portland General Electric (Oregon), Puget Sound Energy (Washington), San Diego Gas and Electric Company (SDG&E, in California), Southern California Edison (SCE, in California), and Xcel Energy (Minnesota). Some of these mechanisms have been in place for a number of years. In addition, the Natural Resources Defense Council ("NRDC") has supported revenue decoupling for both gas and electric utilities as a means of addressing utility disincentives to promote conservation.~~

~~The OUCC cited our rejection of Vectren South Electric's proposed decoupling mechanism in Cause No. 43839 (Order dated April 27, 2011) as a basis for rejecting Petitioner's proposal in this case. However, in Cause No. 43839, we expressly acknowledged "that creative rate designs, which enhance the efficient use of energy such as time-differentiated rates, may influence the attractiveness of a decoupled rate design." (Order to Cause No. 43839, pp. 86-7.)~~

~~In this case Petitioner has presented multiple creative rate designs intended to enhance the efficient use of energy in addition to its ongoing commitment to energy efficiency activities. For instance, the Company has proposed to modify its base residential rate design and customer charge,~~

~~introduce a dynamic pricing pilots, and is implementing a volt/VAR program that is expected to reduce customer bills. Schedule CPP: Critical Peak Pricing, Schedule VPP: Variable Peak Pricing and Schedule VPP-D: Variable Peak Pricing are all designed to incent customers to shift or reduce their electric consumption during particular periods. As these pilots become more widely available, the potential for revenue erosion is significant. Mr. Bailey indicated that the impact of these programs when made available to Petitioner's entire customer base could potentially run into the tens of millions.~~

~~Petitioner's proposal to decouple sales from usage for residential and small commercial service allows it to pursue these important initiatives without financial harm and factoring lost fixed cost recovery into its decisions. For the foregoing reasons, we approve Petitioner's proposed RDM for a five-year term, at which time Petitioner must seek to extend the program in either a base rate case or separate proceeding~~.

16. Rate Adjustment Mechanisms.

a. Rider 70. As established in the Company's last base-rate proceeding (Cause No. 42359), $14.7 million is built into base rates to represent profits from non-native sales. Any amount above or below this amount is split evenly between customers and the Company and trued up in annual Rider 70 proceedings. The Company cannot, however, apply a net annual off-system sales profit of less than zero. In this case, the Company proposes to change the amount embedded in base rates and to change certain details about how non-native sales margins are shared. Specifically, the Company proposes to track the entire amount of non-native sales, with zero embedded in base rates. The Company also proposes that customers share in positive as well as potentially negative margins from non-native sales.

i. Petitioner's Evidence. Company witness Swez supported the Company's Rider 70 proposals. He explained that zero should be embedded in base rates because of the volatility of non-native sales. He demonstrated that margins from non-native sales have varied considerably since the last rate case, and have rarely come close to the $14.7 million threshold built into base rates. Given the volatility, he stated that the Company believes non- native sales are more appropriately accounted for totally through a tracker rather than through any fixed base rate component. He testified the Company's proposal is reasonable due to the variability of non-native margins, and the fact that the realization of margins is largely outside of the Company's control.

With regard to the proposal to include negative (net loss) non-native margins in the sharing mechanism, Mr. Swez stated that sharing both opportunities and risks equally is appropriate. He stated that the negative non-native margins are the result of operating a power system for the greater good of native retail customers, and assigning financial responsibility for these losses solely to the Company is a punitive consequence of the current mechanism.

Mr. Swez also testified about the Company's proposal to include a new category of non-native sales in the Rider 70 sharing mechanism. He explained that currently, the Company does not engage in physical energy sales beyond the MISO border. In the RTO construct, non-native energy sales are an accounting concept. He testified that all of the Company's generation is dispatched into the MISO market and is designated as native or non-native after the fact. As a result, he stated, non-native sales are energy sales that take place in the MISO energy markets when dispatched generation exceeds native-load customer requirements. He contrasted this with the historic native load wholesale sales, which are long-term sales of energy and capacity to traditional wholesale customers of the Company such as Hoosier Energy, IMPA, and Wabash Valley. He noted that because these traditional native load wholesale sales are long-term sales commitments, Duke Energy Indiana plans and builds for these long-term sales. Mr. Swez explained that Duke Energy Indiana is changing its non-native sales strategy. Whereas previously the Company pursued energy only and capacity-only sales to MISO, in order to continue to optimize the value of its generating assets and to adapt to a rapidly evolving energy market landscape, the Company is now also pursuing a non-native sales strategy that includes short-term bundled sales of market-priced capacity and energy to wholesale customers. Mr. Swez noted that the sustained low natural gas prices and increasing renewable energy penetration have created an extremely competitive short-term market environment. As a result, he explained, the traditional wholesale rate structure that assigns average system costs of a diverse fleet of resources is not currently competitive against independent power pricing. He testified that utilities such as Duke Energy Indiana have experienced erosion in wholesale sales portfolios as their contracts based on embedded system costs expire. In addition, he stated, RTO capacity markets have failed to fully price the fixed costs associated with building and maintaining generation. Mr. Swez testified that, with market prices consistently below the Company's full cost of production, the Company expects its traditional native-load wholesale sales portfolio to continue to diminish. And, he added, as these traditional wholesale sales contracts terminate and are not renewed, the balance of the Company's wholesale and retail loads shift, with more of the system costs necessarily shifted to and absorbed by retail customers.

For these reasons, going forward the Company proposes to pursue a new category of sales -- short-term bundled non-native sales contracts that can both meet changing wholesale customer needs and compete with current market prices. He explained that these new short-term bundled non-native contracts will allow the Company to more fully maximize the utilization of its generation portfolio and minimize additional cost allocations to retail customers. He stated that contributions to fixed costs captured through these new agreements, even if they do not fully recover embedded costs, will lower the cost that would be re-allocated to retail customers as current agreements expire. He emphasized that these contracts are non-native sales of capacity and energy for a contract term of five years or less. Further, he explained that they will be negotiated and priced competitively with the market, with bundled contract prices expected to cover energy costs and make a contribution to fixed costs. He testified that, faced with a shrinking wholesale portfolio, these contracts will create incremental value for customers while generation-fleet system costs remain above market. He offered that this short-term bundled sales strategy should provide the Company and its retail customers with a premium above day-ahead and real-time MISO prices. He stated that thus far, the Company has entered into one of these new category sales – a 5 year, 100-megawatt contract for capacity and energy, expiring in 2021. The Company proposes that going forward, for new bundled capacity and energy contracts, including this one existing contract, the associated costs and revenues will be shared 50/50 between the Company and its customers through Rider 70.

ii. <u>OUCC's Evidence and Intervenors' Evidence</u>. OUCC's witness Boerger agrees with the Company's proposal to embed zero non-native sales margins in base rates, but only if the Company allocates 100% of such sales margins to customers. In addition, Dr. Boerger recommends that short-term bundled non-native sales be subject to a sharing mechanism wherein customers receive 80% of the proceeds of such sales and that an amount of $12.7 million be embedded in base rates. He also recommended that the Company be ordered to return the amount of net profit realized on the existing short-term bundled non-native contract beginning June 1, 2017 (Cause No. 44348 SRA-5) and continuing through the date base rates are changed in this proceeding. Dr. Boerger also testified that the OUCC opposes sharing negative margins in Rider 70. Similarly, Industrial Group witness Dauphinais opposed the combination of zero embedded in base rates, sharing of anything other than 100% of non-native margins with customers, and sharing negative margins. Kroger's witness Bieber also recommended 100% of non-native sales margins be provided to customers.

iii. <u>Petitioner's Rebuttal Evidence</u>. In rebuttal testimony, the Company stated that it was agreeable to sharing 100% of traditional non-native sales with customers, including negative margins, with zero embedded in base rates. However, the Company reiterated that, for its new short-term bundled non-native energy and capacity sales, it believed an incentive in the form of 50/50 sharing of margins was appropriate to incentivize pursuit of this new sales strategy. Mr. Davey testified that the Company believes it's important to have an incentive to continue to pursue short-term bundled non-native sales when the Company has surplus capacity. He stated that the Company's proposed 50/50 sharing mechanism provides such an appropriate incentive. However, Mr. Davey and Mr. Swez both emphasized, embedding any amount in base rates associated with these sales does not make sense given their short-term nature. Additionally, both witnesses emphasized that the only existing such contract expires in 2021, and the Company is not making long term capacity planning decisions related to this contract. Therefore, the Company stands by its initial proposal related to short-term bundled non-native sales.

Mr. Davey also testified that the Company does recognize there is a difference between the level of effort required to pursue such bilateral sales and traditional non-native sales, which reflect the difference between native load and generation. As such, the Company is agreeable to crediting retail customers with the net benefits of 100% of traditional, MISO-derived non-native sales margins, through Rider 70. He stated his belief that this compromise proposal recognizes the importance of aligning incentives between customers and shareholders, and results in a reasonable ratemaking proposal.

Company witness Sieferman addressed Dr. Boerger's recommendation that the Company refund net margins realized on the one existing short-term bundled non-native sale. Ms. Sieferman stated that the current base rate case is the appropriate time to address the prospective treatment for the new short-term bundled bilateral contract, which the Company did through its ratemaking proposal in this proceeding. She stated that this new category of sales, the short-term bundled non-native contract, is clearly different from both the Company's long-term native load wholesale contracts and also the non-native sales of excess generation to MISO that were contemplated in the past for inclusion in Rider 70.

iv. <u>Commission Discussion and Findings</u>. The evidence is clear that traditional non-native sales margins are quite volatile, and that embedding any level of such sales margins in base rates is unlikely to be fair to one party or the other. Additionally, the evidence shows that Petitioner currently has only one bilateral short-term bundled sales contract in place, and it expires in 2021 which leads us to conclude that the margins from that contract are unlikely to be recurring while these rates are in effect. Accordingly, we find that Petitioner's base rates should reflect zero for non-native sales margins.

As for sharing of non-native sales margins, we accept the parties' agreement to credit retail customers with 100% of the traditional, MISO-derived non-native sales margins through Rider 70. The evidence shows that negative margins, while infrequent, do occur due to no fault by or action by Petitioner. Given this fact, coupled with Petitioner's willingness to credit 100% of MISO-derived non-native sales margins to retail customers, we approve the reflection of negative margins in the calculation of Rider 70 margins to be shared. Further, we accept Petitioner's proposal to share, on a 50/50 basis, sales margins from the new category of short-term bundled non-native sales. We agree with the Company, and the evidence demonstrates, that there is a difference in effort, creativity, and initiative, between pursuing and achieving such bilateral sales, compared to the traditional non-native sales made through the MISO markets. As noted by the Petitioner, this new category of short-term bundled non-native sales is clearly different from both the traditional non-native sales through MISO and the long-term wholesale native load contracts, therefore it's most appropriate to discuss and determine ratemaking treatment within this proceeding. While we cannot reach back and credit customers with any past margins (nor do we believe this is appropriate), we urge the Company to take advantage of the 50/50 sharing incentive and actively pursue future short-term bundled non-native sales in order to maximize surplus capacity and energy for the benefit of its retail customers.

b. <u>Edwardsport IGCC.</u>

i. <u>Petitioner's Evidence</u>. Witness Douglas provided testimony regarding changes Duke Energy Indiana is proposing to its IGCC Rider. Consistent with the terms of a settlement agreement approved by the Commission's June 5, 2019 final order in IGCC-17 (the "IGCC-17 Order") (the "2018 IGCC Settlement Agreement"), Ms. Douglas explained the Company included Edwardsport plant investment and operating expenses in the proposed base rates. Ms. Douglas stated the Company is proposing to discontinue tracking Edwardsport investment and operating expenses in the IGCC Rider, effective with implementation of new base rates in this proceeding, at which time Duke Energy Indiana is proposing to eliminate the IGCC Rider. Ms. Douglas explained the IGCC-17 Order left the issue of base rate treatment for Edwardsport investment and operating expenses for this proceeding, and that the Company is requesting the Commission approve this base rate treatment for Edwardsport and discontinue the IGCC Rider.

Ms. Douglas testified that should the Commission approve this ratemaking proposal, the 2018 IGCC Settlement Agreement provided that a final reconciliation of the IGCC Rider will be made as part of the first practicable Environmental Compliance Cost Recovery ("ECR") rider ("ECR Rider") filing following the issuance of an order in this proceeding. Ms. Douglas stated the reconciliation calculation will incorporate the 2018 IGCC Settlement Agreement O&M Caps from 2018 and 2019 to ensure customers pay only for the lesser of actual O&M costs incurred in 2018 and 2019 and the agreed upon retail jurisdictional caps of $97.6 million for 2018 and $96.0 million for 2019. The reconciliation will include the other terms set out in the 2018 IGCC Settlement Agreement.

Ms. Douglas explained there are other items included in the IGCC Rider that will be included in the ECR Rider upon implementation of new base rates, including an amount for amortization of retail jurisdictional operating costs incurred in excess of amounts being recovered through IGCC Rider rates from June 7, 2013 through August 2016. Ms. Douglas testified the 2018 IGCC Settlement Agreement required the Company to propose base rates be set using a $20 million annual amortization amount, which is what the Company included in the development of base rate revenue requirements in this Cause. Ms. Douglas explained additionally that a $10 million annual credit would be included in the ECR Rider to offset the $20 million in base rates until a total of $30 million benefit of the 2018 Settlement Agreement reduction was refunded through rates.

Ms. Douglas testified there are three IGCC facility tax incentive credit items currently included in the IGCC Rider that the Company has not included in its development of proposed base rates. These include a credit for the retail jurisdictional portion of the $15 million annual Indiana Coal Gasification Technology Investment Tax Credit, a credit for the retail jurisdictional portion of the ten-year property tax abatement from Knox County, and a credit for the retail jurisdictional portion of the thirty-year reimbursement due to designation of Edwardsport as a Tax Increment Financing ("TIF") District. As explained in the testimony of Company witness Panizza, an additional credit for the retail jurisdictional portion of the annual federal Advanced Coal Investment Tax Credit was planned to be included in the IGCC Rider, but has not been included in the proposed base rates to ensure compliance with the federal income tax normalization requirements. Ms. Douglas explained the Company plans to include these tax incentive benefits as credits to customer rates in its Rider 67 Credits Rider.

Ms. Douglas explained the Company's ratemaking proposals regarding costs and credits currently included in the IGCC Rider are reasonable, as the request is consistent with past practice in Indiana for capital riders to subsequently include in base rates in-service plant receiving CWIP ratemaking treatment via a tracker. Ms. Douglas supported her statement by reference to the Company's last base rate case and the approval of Southern Indiana Gas and Electric's handing of investment and operating expenses related to certain Qualified Pollution Control Equipment in Cause No. 43839. She also stated excluding IGCC Incentive Tax Benefit credits from base rates and moving them to Rider 67 is a transparent way to show parties that customers are indeed continuing to get these credits. Ms. Douglas explained that Rider 67 is an efficient way to pass these credits back to customers, and is currently the case with the amortization of the unprotected EDIT created due to the reduction in federal income taxes resulting from the TCJA.

ii. **OUCC's Evidence**. OUCC witness Kollen explained the effect of terminating the IGCC Rider, as proposed by Duke Energy Indiana, would result in a greater revenue requirement in the test year and in subsequent years. Mr. Kollen asserted that the Company seeks to include costs in the base revenue requirement that it could not include in the IGCC Rider, such as fuel and M&S inventories in rate base. Additionally, Mr. Kollen stated the base revenue requirement will not decline as the IGCC cost curve declines due to additional accumulated depreciation and additional ADIT until the Company's next base rate case and base rates are again reset in that proceeding. Mr. Kollen believes the Commission should continue to track the declining IGCC cost curve after December 31, 2020.

Mr. Kollen recommended the Commission reflect the reduction in the IGCC plant-related revenue requirement (grossed-up return on the increase in accumulated depreciation and the reduction in the grossed-up cost of capital due to the increase in ADIT) in either the ECR Rider or Credits Rider. Mr. Kollen claimed this would maintain the existing benefit to customers of the declining IGCC cost curve that otherwise would be lost under the Company's proposal to roll-in and fix the base rate recovery until the Company's next base rate case.

iii. Petitioner's Rebuttal Evidence. Company witness Davey disagreed with Mr. Kollen's recommendation that Edwardsport essentially continue to be included in a rider, rather than included in base rates. Mr. Davey emphasized the legislature provided for the ability to recover costs associated with gasification projects in rates through a rider mechanism. Mr. Davey stated that the Company and the settling parties agreed in both the original IGCC settlement agreement and the 2018 IGCC Settlement Agreement that when the Company had a base rate case, Edwardsport would be included in base rates, which is what the Company has proposed and which is consistent with how other capital riders have been treated in the past during a base rate case. Mr. Davey also voiced concern with Mr. Kollen's recommendation that the only portion of Edwardsport that should be included in the rider is the declining balance of rate base, and credit of tax credits, but no other costs such as O&M and new capital additions needed to operate the plant. Mr. Davey concluded that the costs associated with Edwardsport should be included in base rates and in rate base, as proposed by the Company.

Company witness Douglas also addressed Mr. Kollen's recommendation. Ms. Douglas stated the OUCC's proposal was not traditional Indiana rate recovery for assets that are moved from being tracked in a rider to rate base. For instance, in the Company's last base rate case, Duke Energy Indiana rolled NOx environmental plant that had previously been tracked in Rider 62 into base rates, but Mr. Kollen does not put forth a compelling reason to deviate from standard ratemaking practice. The Company is proposing to handle Edwardsport plant similarly to how it handled all other in-service generating plant that was used and useful for providing service to customers during the test year. However, Ms. Douglas pointed out that under Mr. Kollen's proposal, the revenue the Company receives for return on the plant declines, while the costs are still subject to increasing. As such, the Company's ability to manage cost increases and earn a fair return until the next base rate case is impaired. Ms. Douglas testified this one-way tracking proposal is unfair, unreasonable, and unbalanced.

iv. Commission Discussion and Findings. In this proceeding, Duke Energy Indiana seeks to implement a provision of the 2018 IGCC Settlement Agreement, which we approved in our IGCC-17 Order. In relevant part, it stated: "In addition, the 2018 Settlement Agreement provides that Duke Energy Indiana will not file an IGCC Rider proceeding in 2019 or 2020, and that the Settling Parties intend for Duke Energy Indiana to include the Edwardsport investment and operating expenses in base rates in its next retail base rate case and to discontinue the tracking of Edwardsport via the IGCC Rider." See page 33 of the IGCC-17 Order. The OUCC was a party to the 2018 IGCC Settlement Agreement, and it continues to be bound by its agreement.

Even if the OUCC had not already agreed to the rate mechanism procedures in the 2018 IGCC Settlement Agreement, Duke Energy Indiana's proposal would still be reasonable and appropriate. The Company's proposal is consistent with traditional Indiana ratemaking, and the proposal to handle Edwardsport is consistent with how the Company handled all other in-service generating plant that was used and useful for providing service to customers during the test year. We find that the proposal set forth by Duke Energy Indiana is reasonable, consistent with Indiana law and the 2018 IGCC Settlement Agreement, and supported by the evidence, and we approve it.

c. DSM/EE Rider.

i. Petitioner's Evidence. Company witness Douglas explained certain changes Duke Energy Indiana is proposing to its energy efficiency ("EE") Rider, the nature and extent of which are dependent on whether the RDM is approved. Ms. Douglas explained the proposed RDM would replace the lost revenue recovery mechanism ("LRAM") for recovery of lost revenues resulting from the Company's EE programs for those customers who are a part of the proposed RDM. Ms. Douglas stated that as such, with the approval of the RDM, the items included in the EE Rider for the Residential and Commercial customer groups will exclude lost revenues for energy savings resulting from Company-sponsored EE programs going forward from the time of rate implementation.

Ms. Douglas next discussed some cosmetic changes proposed to its EE Rider, including numbering, and revision of the revenue conversion factors. Ms. Douglas also explained the Company is proposing to remove all EE program costs, including administrative and EM&V costs, and all shareholder incentives from the cost of service and track these costs in the EE Rider from the zero base. Ms. Douglas also described the process of handling lost revenues currently included in the EE Rider upon implementation of new base rates.

Ms. Douglas explained that the Company's ratemaking proposals regarding the EE Rider are reasonable, as keeping all energy efficiency costs in the EE Rider is appropriate given the statutory requirement to propose plans consistent with each IRP. Ms. Douglas described that because plans can and will change, and the level of EE Rider rates may therefore be volatile.

ii. OUCC's Evidence. OUCC witness John E. Haselden stated some concerns regarding lost revenue recovery for DSM programs delivered in 2020. Mr. Haselden asserted that the Company has proposed, as an alternative to decoupling, to collect through the EE Rider lost revenues for measures implemented in 2020 over the measure's expected useful life. Mr. Haselden stated the OUCC has concerns about expected useful life assumptions the Company is using for certain measures, while also noting that Duke Energy Indiana has not yet filed its next DSM plan for the period beginning 2020.

Mr. Haselden recommended the Commission defer future DSM costs, lost revenues, and shareholder incentives to the forthcoming DSM plan case with the condition any issues will be litigated therein and no implied or explicit approval of any issues will be decided in this case.

iii. Petitioner's Rebuttal Evidence. Company witness Davey agreed with Mr. Haselden's recommendation that the Commission defer future DSM costs, lost revenues, and shareholder incentives to the forthcoming DSM plan case with the condition any issues will be litigated therein.

iv. Commission Discussion and Findings. Duke Energy Indiana and the OUCC agreed to defer future DSM costs, lost revenues, and shareholder incentives to the forthcoming DSM plan case with the condition any issues will be litigated therein. We approve of the handling of these aspects of the EE Rider in such a fashion. With respect to all other aspects of Duke Energy Indiana's EE Rider proposals as set forth by Ms. Douglas' revised direct testimony, including but not limited to the impact of the approved-RDM on the LRAM, the Commission approves them as proposed.

d. Rider 62.

i. Reagent Costs.

(A) Petitioner's Evidence. Company witness Mr. Mosley explained that reagents are included in the base cost of power production O&M, and he also discussed that reagent expenses necessary to operate the generating stations vary directly with generation output of the units. He testified that reagent consumption rates also vary with coal quality, and commodity and delivery transportation prices of the reagents themselves can show volatility.

Mr. Mosley explained the Company is proposing to build into its base rates a representative level of reagents. Due to the variability of reagent expenses, however, Company witness Graft explained that Duke Energy Indiana is proposing to track its reagent expense, both up and down from the level built into rates, through its consolidated Rider 62. Ms. Graft stated this will protect customers to the extent actual reagent costs are less than the amount in base rates but also protects the Company if actual reagent costs exceed the amount in base rates.

(B) OUCC's Evidence. OUCC witness Blakley addressed the Company's reagent expense tracker proposal. He stated that Duke Energy Indiana indicated the 2020 forecast for reagent expense it is proposing to embed in base rates is $48,539,000, and the Company is proposing to track up and down from this level based on actual annual expenses, with the variance collected from or refunded to customers through Rider 62. Mr. Blakley asserted the practice of setting aside and tracking a single O&M expense outside of base rates is "piecemeal ratemaking." Mr. Blakley stated the Commission denied requests for continued tracking of O&M expenses when associated pollution control equipment is rolled into base rates, including Vectren South's Electric Cause No. 43839. Mr. Blakley stated traditionally O&M expenses related to plant investment are placed into base rates at the same time the associated plant investment is placed into rate base during a rate case.

Mr. Blakley recommended the denial of the Company's proposal to track incremental reagent expense. In the event the Commission allows the Company to track incremental reagent expense outside of base rates, Mr. Blakley recommended the Commission require the Company to recalculate its return on its embedded pollution control investment to reflect the depreciated value and use its existing Rider 67 Credits Rider to pass back the difference as a credit to ratepayers.

(C) Petitioner's Rebuttal Evidence. Ms. Graft addressed the fact that Mr. Blakley's citation to the Commission's April 27, 2011 Order in Cause No. 43839 does not support his position. Ms. Graft pointed out that such Commission Order reflected the uncertainty as to the potential for chemical and catalyst costs to vary going forward. However, Ms. Graft stated that such uncertainty does not exist in this proceeding. She reiterated Mr. Mosley's direct testimony, which established the variability of the Company's reagent expense, and which distinguishes it from the Order in Cause No. 43839.

Ms. Graft stated her disagreement with Mr. Blakley's position. In addition to the variability in reagent expense established by Mr. Mosley, Ms. Graft explained that continued tracking protects customers if the actual costs of reagent expenses are lower than the amount in base rates. She also explained discontinuing the tracking of these costs is inconsistent with the Clean Energy Project Statute, which provides for timely recovery of clean energy project costs incurred during ongoing operation.

Ms. Graft also stated opposition to Mr. Blakley's proposal to use Rider 67 to credit customers for the effect of declining environmental rate base following implementation of new base rates as an offset to tracking reagent expense through Rider 62. She testified the historic practice is for projects included in riders to be rolled into rate base at the time of a subsequent base rate case, which occurred with environmental projects in the Company's last rate case. To the contrary, Ms. Graft pointed out that continuing to provide customers the benefit of declining rate base for these projects in between rate cases is inconsistent with traditional ratemaking. She also asserted it would be one-sided to track declining environmental rate base when the Company will not be tracking future capital maintenance projects associated with the environmental plant being rolled into base rates in this proceeding.

(D) **Commission Discussion and Findings**. Duke Energy Indiana is proposing to build into its base rates a representative level of reagent expense, and also track its reagent expense, both up and down from the level built into rates, through its consolidated Rider 62. The evidence presented established that Duke Energy Indiana's reagent expense is and will continue to be variable, and there was no evidence offered to rebut that fact. The establishment of reagent expense variability distinguishes this from the rationale in the Commission's April 27, 2011 Order in Cause No. 43839, in which variability was uncertain.

Cost trackers related to generation operations or the provision of power to customers have been used for many years. For example, in a prior base rate case, PSI Energy, Inc. (the Company's predecessor) was allowed to track volatile and difficult to control variable costs for gasification services from Destec. PSI Energy, Inc., Cause No. 40003, pp. 87-88 (IURC 9/27/96). Similarly, because purchased power demand costs can be volatile and are a critical part of reliability, we have authorized tracking of changes to such costs. PSI Energy, Inc., Cause No. 41448, pp. 10-11 (IURC 5/31/00). When volatile costs are incurred in response to governmental requirements, such as compliance with environmental regulations, they also may be more likely to be the subject of a tracker because the utility must incur such costs as part of providing service to customers. Here, as reflected in our prior orders, Duke Energy Indiana is required to continue to incur reagent expenses as part of the base cost of power production O&M.

Furthermore, the structure of tracking these types of variable expenses is reasonable and balanced. This is not a one-way ratchet. Instead, it would protect customers to the extent actual reagent costs are less than the amount in base rates, and also protect the Company if actual reagent costs exceed the amount in base rates. Furthermore, discontinuing the tracking of these costs is inconsistent with the Clean Energy Project Statute, which provides for timely recovery of clean energy project costs incurred during ongoing operation. That is precisely what the Company has proposed. As such, in these circumstances where there is a history and continued likelihood of cost volatility due to multiple factors beyond the Company's control, as well as a demonstration of the significant magnitude of these costs, we find that Duke Energy Indiana's proposal to track reagent costs should be approved.

Additionally, we find persuasive Ms. Graft's testimony in opposition to Mr. Blakley's proposal to use Rider 67 to credit customers for the effect of declining environmental rate base following implementation of new base rates as an offset to tracking reagent expense through Rider 62. We agree it is historic practice for projects included in riders to be rolled into rate base at the time of a subsequent base rate case, and continuing to provide customers the benefit of declining rate base for these projects in between rate cases is one-sided because the Company will not be tracking future capital maintenance projects associated with the environmental plant being rolled into base rate in this proceeding. Therefore, we reject Mr. Blakley's recommendation.

ii. <u>Emission Allowance Costs.</u>

(A) <u>Petitioner's Evidence</u>. Duke Energy Indiana witness Graft described the Company's proposal for its current Rider 63 and its consolidation into Rider 62. As Company witness Sieferman discussed, the Company is requesting a regulatory asset for its native SO_2 emission allowance inventory balance. Ms. Graft stated under this proposal, native SO_2 emission allowance costs would no longer be tracked through Rider 63, as the Company does not expect to incur any additional consumption expense for native SO_2 emission allowances. However, Ms. Graft testified there may be future native NOx emission allowance consumption expense, and the Company may also have gains or losses on the sale of native SO_2 or NO_x emission allowances, both of which would be included in the consolidated Rider 62.

(B) <u>OUCC's Evidence</u>. OUCC witness Armstrong testified the public has no objection with Duke Energy Indiana's proposal to transfer the native SO_2 emission allowance inventory balance to a new regulatory asset account, and to decrease the native SO_2 emission allowance expense to zero. Ms. Armstrong stated the proposal benefits both the Company and its ratepayers.

Ms. Armstrong, however, did take issue with Duke Energy Indiana's proposal to continue tracking any emission allowance expense via Rider 62. She argued the Company's emission allowance costs have been stable over the past several years, and emission allowance costs are not expected to be significant going forward. Ms. Armstrong stated that Duke Energy Indiana is unlikely to incur volatile or significant emission allowance costs over the next several years, and therefore tracking these costs is no longer necessary. She recommended the Commission deny the Company's proposal.

Ms. Armstrong said the Company should continue to offset the past costs of emission allowances it will recover through the proposed regulatory asset by selling allowances whenever possible, and net proceeds of such sales should be credited to customers through Rider 62 in future ECR filings.

(C) <u>Petitioner's Rebuttal Evidence</u>. Ms. Graft, in rebuttal, stated the Company agrees to discontinue tracking native emission allowance consumption expense upon the implementation of new base rates. However, Ms. Graft testified that Duke Energy Indiana reserves the right to seek tracking of emission allowances pursuant to Indiana statutes, rules and regulations in future proceedings, as it is possible new emission allowance regulations will be enacted or existing emission allowance expense may become more volatile in the future. She reiterated that the Company plans to include any gains or losses on the sale of native emission allowances in the consolidated Rider 62.

(D) **Commission Discussion and Findings**. With Duke Energy Indiana's rebuttal modification on the issue of tracking native emission allowance consumption expense upon the implementation of new base rates, there appears to be no dispute among the parties on this topic. We conclude it is reasonable for Duke Energy Indiana to transfer the native SO_2 emission allowance inventory balance to a new regulatory asset account (as we also discussed earlier in this order in the regulatory asset section and also later in this Order in the accounting deferral section), to decrease the native SO_2 emission allowance expense to zero, and to discontinue tracking of native emission allowance consumption expense upon the implementation of new base rates. It is also reasonable for the Company to reserve the right to seek tracking of emission allowances pursuant to Indiana statutes, rules and regulations in future proceedings. Accordingly, we approve Duke Energy Indiana's emission allowance proposals as modified in its rebuttal testimony.

e. **Rider 67.**

i. **Petitioner's Evidence**. Company witness Douglas described the changes the Company is proposing to its Credits Rider. She stated that in addition to the ongoing TCJA credit currently in the Credits Rider, pursuant to the TCJA Settlement Agreement, a one-time $1.9 million credit will be included in the Rider in January 2020 and the ongoing additional credit amortization of protected EDIT will also begin in January 2020. She added the Company is also proposing to include the deferred 2018 and 2019 amounts of protected EDIT amortization in the Credits Rider. Ms. Douglas explained the Company is proposing to include certain IGCC facility tax incentive credits in the Credits Rider, which are currently included or planned to be included in the IGCC Rider. Additionally, the Company plans to include additional credits in this rider as the regulatory assets for which amortization is being included in base rates becomes fully amortized.

Ms. Douglas further described a two-step rate adjustment, such that the Credits Rider is planned to be used during the first step of implementing the new base rates by crediting customers (upon review and Commission approval in a compliance filing) with the difference between what final base rates are using the proposed forecasted Test Period revenue requirements, reflecting used and useful plant in-service as of December 31, 2020, and what they would be using the known actual used and useful plant in-service as of December 31, 2019. Ms. Douglas explained a second step process with the Credit Rider to ensure that customers continue to pay for used and useful plant only as a result of the final base rates approved during this proceeding.

Ms. Douglas said that in addition, the Credits Rider will also be revised to remove the credit to remove the 1994 Cinergy Merger Costs currently in the rider, update allocations to rate classes consistent with this proceeding instead of Cause No. 42359, and include the calculated revenue requirements differential by rate class for the two-step rate adjustment.

Ms. Douglas testified these ratemaking proposals are reasonable, consistent with the requirements of the TCJA Settlement, provide transparency that the credits are being provided to customers, and via the administratively convenience means under the Thirty-Day Filing Rules.

ii. **OUCC's Evidence**. OUCC witness Eckert stated some concerns with the proposed Credits Rider. He argued that continuing Rider 67 as a 30-Day filing, which would track at least nine items that use three allocation methodologies would not allow the OUCC enough time to review the filing. Thus, if the Commission accepts the 30-Day filing proposal, Mr. Eckert recommend the Company be required to provide a draft of its filing, as well as workpapers, at least 60 days in advance of the file date, and schedule a technical conference with the OUCC to explain its filing and workpapers prior to filing. Alternatively, Mr. Eckert stated the Commission should deny the request for a 30-Day filing, and instead implement a tracker proceeding.

As discussed in other sections of this Order, OUCC witnesses Kollen, Blakley, and Hand discussed and recommended additional components be added to the proposed Credits Rider.

iii. **Petitioner's Rebuttal Evidence**. Ms. Douglas stated the Company's agreement that, for ongoing Rider 67 filings, the extended 60-day preview and technical conference outlined by Mr. Eckert is warranted and reasonable. With this, Ms. Douglas believed that continuing to file Rule 67 under the Commission's 30-Day process is reasonable. However, Ms. Douglas pointed out that this agreement did not extend to the timing and process related to the one-time approval of Step 2 rates under the Company's Two-Step Base Rate Implementation Process proposal. This is addressed in the Step 2 Rate Increase Section below.

iv. **Commission Discussion and Findings**. The Commission approves of the agreement of Duke Energy Indiana and the OUCC regarding the Rider 67 process. Specifically, Duke Energy Indiana shall continue to afford itself of the Commission's 30-Day procedures with regard to Rider 67, but the Company shall provide a draft of its filing, as well as workpapers, to the OUCC at least 60 days in advance of the file date, and schedule a technical conference with the OUCC to explain its filing and workpapers prior to filing. This will provide the public a reasonable opportunity to preview all the various items that could be included in a Rider 67 filing.

Duke Energy Indiana proposed a number of items be included in Rider 67, including items related to the TCJA Settlement Agreement, other tax items, certain Edwardsport IGCC tax incentive credits, and additional credits as regulatory assets for which amortization is being included in base rates become fully amortized. While the merits of these items are discussed elsewhere in this Order, we reiterate here that Duke Energy Indiana's proposals for inclusion in Rider 67, as well as the proposed allocations, are reasonable, supported by the evidence, and approved. We also approve the removal of the 1994 Cinergy Merger Costs credits, which have been fully accounted for.

The OUCC recommended that additional components be added to Rider 67. The merits of these components are discussed elsewhere in this Order. For clarity, we reiterate here that those proposals are not approved by the Commission.

f. **Discontinued Riders.**

i. Petitioner's Evidence. Duke Energy Indiana is proposing to discontinue several currently-existing riders. As discussed above, Ms. Douglas testified the Company is proposing to discontinue the IGCC Rider (Rider 61); Ms. Graft explained the consolidation of the SO_2, NOx, and Hg Emission Allowance Adjustment (Rider 63), as well as the Environmental Compliance Operating Cost Adjustment (Rider 71) into consolidated Rider 62; and Riders 64 and 69 will continue to be vacant.

ii. OUCC's Evidence. Mr. Eckert testified that the OUCC does not oppose keeping these rider/tariff numbers in place, but the OUCC is not in favor of riders not currently in use being "shelved" for future use. He stated that should Duke Energy Indiana propose to utilize these riders/tariffs for future cost recovery, the OUCC recommends the Company make a formal request through a docketed proceeding and receive Commission approval to do so.

iii. Petitioner's Rebuttal Evidence. Company witness Douglas indicated general agreement with Mr. Eckert's proposal that a docketed proceeding be initiated and Commission approval be received in order to utilize the rate adjustment riders being discontinued in this proceeding. The one slight change Ms. Douglas proposed was to also allow for the use of a 30-Day filing should the Company need to reuse the rider/tariff numbers 61, 63, 64, 69 and 71, as appropriate depending on the nature of the reuse of the vacant numbers. Ms. Douglas explained this is consistent with what the Company has done previously when it requested Commission approval for the use of a new rider, whether when using a new, previously unused rate adjustment rider number or reusing a previously used but currently unused number.

iv. Commission Discussion and Findings. The Commission approves of the discontinuation and consolidation of rider/tariff numbers 61, 63, 64, 69 and 71, as proposed by Duke Energy Indiana. We also agree with the concept advanced by the OUCC, and agreed to by the Company, that the Company must make a formal request through a docketed proceeding and receive Commission approval in order to propose to utilize these riders/tariffs for future cost recovery, but with the one slight change proposed by the Company. Specifically, the Company desires to be allowed the use of a 30-Day filing should the Company need to reuse the rider/tariff numbers 61, 63, 64, 69 and 71, as appropriate depending on the nature of the reuse of the vacant numbers. Ms. Douglas explained this is consistent with what the Company has done previously when it requested Commission approval for the use of a new rider, whether when using a new, previously unused rate adjustment rider number or reusing a previously used but currently unused number. We are persuaded that the flexibility provided by this set up will facilitate appropriate efficiencies in the future, and authorize the Company to retain this ability.

17. Tariff Provisions. Duke Energy Indiana has proposed several modifications, both clerical and substantive, to its retail electric tariff, as discussed in the revised direct testimony of Company witness Flick. Many of the proposed modifications were unopposed by any party. The unopposed modifications in the General Terms and Conditions include changes to various definitions; a clarification to the Pick Your Own Due Date program; adding streamlined pricing to the Energy Profiler Online program; an update to the increased transformer size limit under general standards for three phase-service; updates to the remote and manual reconnection charges; and updating details of the after-hours service rate. Mr. Flick explained the proposed revisions to the Lighting tariffs, including the proposal to adjust both the metered and unmetered lighting tariffs. Mr. Flick also described the proposed changes to the *GoGreen* program, in that the Company is seeking authority to offer the program on a permanent basis in light of customer demand. Mr. Flick also described other proposed revisions that were not opposed. Having reviewed the evidence presented, we approve each of these unopposed proposals as reasonable and in the customers' interests.

Certain of the proposed tariff provision modifications were the subject of challenge by other parties. We consider these below.

a. Non-Residential Deposit Rules.

i. Petitioner's Evidence. Company witness Flick sponsored the proposal to modify Section 4.2 of Duke Energy Indiana's tariff, regarding the circumstances around which the Company may seek a new or additional security deposit from existing non-residential customers. The Company's current tariff provides that such a deposit may be required "at the Company's discretion." Company witness Lesley Quick described the Company is proposing to clarify that such deposit may be required based on the customer's overall financial condition or creditworthiness, which may include external information obtained from credit reporting agencies and public records. Ms. Quick explained this improved language is designed to provide customers with additional insight into how the Company may decide to require the deposit.

ii. Industrial Group's Evidence. Industrial Group witness James R. Dauphinais testified the non-residential customer deposits provisions, claiming they provide Duke Energy Indiana with excessive discretion. He argued the provisions give the Company the discretion to require a non-residential customer make a deposit, even if that customer has made satisfactory payment over a reasonable period of time. He also took issue with the proposed provisions not explicitly requiring the Company to provide written notice of the facts upon which it bases its decision to require a non-residential customer make a deposit, and do not provide them an opportunity to rebut those facts. Mr. Dauphinais did concede that he is not aware of any serious abuse of discretion to date by Duke Energy Indiana with respect to non-residential deposits.

Mr. Dauphinais alleged the Company's non-residential customer deposit provisions are inconsistent with past Commission orders. Specifically, he cited the Commission's orders in Cause Nos. 43685 and 43526, involving NIPSCO, and stated the commission required creditworthiness be based on objective bases, allow some form of an appeal procedure, and a utility's rules for non-residential customers be fundamentally the same as those for residential customers.

iii. Petitioner's Rebuttal Evidence. Ms. Quick addressed the allegations made by Mr. Dauphinais. First, Ms. Quick explained that there are rational reasons that a non-residential customer should be treated differently from residential customers, which support the Company having increased discretion with respect to non-residential customers. Ms. Quick explained that non-residential customers can have a history of paying their bills, but a company's finances may deteriorate during this time. Ms. Quick said Duke Energy Indiana monitors credit ratings in order to become aware of things like potential insolvency before bankruptcy occurs, in order to protect the Company and its other customers from an uncollectible account. Ms. Quick characterized this as the exercise of prudent discretion.

Ms. Quick, at the evidentiary hearing, explained that Duke Energy Indiana's proposed method of handling deposits for non-residential customers is appropriate. She testified Duke Energy Indiana employs fair and equitable methods of determining creditworthiness, by reviewing credit ratings. She also testified that the deposits earn similar earnings, and Duke Energy Indiana provides the ability to appeal a deposit determination. She stated the Company notifies, by both letter and phone call, the non-residential customer to let them know why a deposit is being assessed, and informs them how they can dispute the deposit determination by phone. Ms. Quick explained that these procedures are consistent with what Duke Energy Indiana currently does, and the Company is proposing to continue them in the future. Tr. p. D-78 to 79. Ms. Quick stated that these facets of the program are in accordance with the Commission's Order in the NIPSCO case, Cause No. 43526. Ms. Quick also stated that several other Duke jurisdictions use credit ratings to assess deposits to non-residential customers, including Florida, South Carolina, North Carolina and Kentucky.

iv. Commission Discussion and Findings. The evidence revealed that Duke Energy Indiana non-residential customer deposit rule is fair and equitable, as is the Company's proposal going forward. Consistent with our determination in Cause No. 43526, Duke Energy Indiana uses objective criteria to ascertain creditworthiness, treats residential and non-residential deposit equally in terms of earnings, and provides non-residential customers notice and an avenue to appeal a deposit determination. While the Company's tariff does not spell out all of these procedures, the evidence demonstrated that the Company does these things now, which equates with Mr. Dauphinais' testimony of a lack of abuse of discretion by the Company. Nonetheless, Duke Energy Indiana's proposed modification to its tariff is intended to provide clarity and more transparency to customers as to the how the Company may decide to require the deposit. We find the proposed modification reasonable, supported by the evidence, and we approve the Company's proposal.

b. Meter Tampering Penalties.

i. Petitioner's Evidence. Ms. Quick testified regarding the Company's proposal to implement a new penalty for tampering with Company equipment. Ms. Quick stated the fee is intended to deter customers from tampering with electric meters, which creates safety hazards and adds to the Company's costs of doing business. Ms. Quick stated that the proposed fee is $200 for residential customers and $1,000 for nonresidential customers. Ms. Quick testified in 2018, there were 892 cases of residential tampering and 16 instances of non-residential tampering, and the total penalty under the proposed program would have been approximately $194,000, which is the forecasted amount of 2020 revenue to be collected from the tamper penalty program. Company witness Flick sponsored the *pro forma* credit adjustment to test period revenues for the program.

ii. OUCC Evidence. OUCC witness Lauren M. Aguilar explained that the OUCC opposes the proposed tamper penalty program. She stated that the Company does not know how many repeat meter tampering offenders it has, and to the extent someone tampers with a meter, Ms. Aguilar believes Duke Energy Indiana should seek criminal prosecution because meter tampering is a felony. Finally, Ms. Aguilar testified that the OUCC recommends denying the Company's proposed meter tampering penalties in any amount and removing the $194,000 revenue adjustment.

iii. Petitioner's Rebuttal Evidence. Ms. Quick responded to Ms. Aguilar's testimony by pointing out that the meter tampering fee was not designed solely to deter repeat offenders, but initial offenders as well. Ms. Quick also emphasized that the Company lacks the ability to criminally prosecute those who engage in meter tampering, and seeking civil damages is time consuming, while the costs would be socialized to all customers. She stated the proposed meter tamper penalty is more prudent and recovers the fees from the specific violators. As such, the requested meter tampering penalties, along with recovery of costs in base rates, best accomplishes the goal of preventing customers from putting themselves and others in unsafe situations.

iv. Commission Discussion and Findings. Based on the evidence provided, the Commission is in agreement with the meter tampering penalties proposed by Duke Energy Indiana. Meter tampering is a grave safety concern, for both customers and others, and the proposed meter tampering fees should serve as a deterrent. While the Company, under the appropriate circumstances, could refer meter tampering to local authorities for potential criminal prosecution, it would be costly and time consuming for Duke Energy Indiana's sole recourse to be civil collection against offenders, in which the costs are socialized and the chance of collection uncertain. The Company's proposed meter tamper penalty is more prudent and recovers the fees from the specific violators. We find the proposed fees of $200 for residential customers and $1,000 for nonresidential customers reasonable to be included in the Company's tariff, and we approve of the *pro forma* credit adjustment of $194,000 built into rates as proposed by the Company.

c. Backup and Maintenance Provisions.

i. Petitioner's Evidence. The tariffs sponsored by Company witness Flick included minor revisions to Standard Contract Rider No. 50, Rate Qualifying Facility ("QF"), Parallel Operation for Qualifying Facility, which addresses backup and maintenance, or standby, service. These minor revisions addressed definitions for contracted capacity and peak periods and, renaming the rider simply as Rate QF.

ii. Industrial Group Evidence. Industrial Group witness Dauphinais explained the definitions of backup and maintenance power, and stated Duke Energy Indiana is required to provide backup and maintenance power to "Qualified Facilities" pursuant to the Public Utility Regulatory Policy Act ("PURPA") and Commission Rule 4.1. Mr. Dauphinais testified the applicable rates and charges for standby service are not specifically stated in Rate QF. Mr. Dauphinais stated that, in the absence of a special contract, the rates, charges and terms of service would be those set forth in the "applicable rate schedules" or "applicable Service Schedules." Mr. Dauphinais concluded that, for a Rate HLF customer, standby service would be provided subject to the rates and terms of Rate HLF, and for a Rate LLF customer standby service would be subject to the rates and terms of Rate LLF. Mr. Dauphinais asserted that this implies the Company's standby service rates are unjust and unreasonable, and contrary to FERC and Commission regulations. Mr. Dauphinais recommended rate design modifications to bring them into compliance with FERC and Commission rules for standby service.

iii. Petitioner's Rebuttal Evidence. Company witness Bailey stated he does not agree with Mr. Dauphinais position. Mr. Bailey first noted there are no historical or current complaints before the Commission related to standby service, and Mr. Dauphinais' reading and interpretation of the Company's tariffs and general terms and conditions does not comport with Company practice. Mr. Bailey testified the Company's experience has been that the provision of standby services is highly contingent on the specific circumstances of the customer and the Company. He stated the Company has two major customers with cogeneration facilities, which are served in different ways with different provisions of service. Mr. Bailey disagrees that these complex provisions can be reduced to a simple smorgasbord of rate options, as Mr. Dauphinais seems to suggest.

Mr. Bailey, in the interest of compromise, stated the Company is willing to consider modest changes to its General Terms and Conditions, with Rate QF to provide additional details on the calculation of standby and backup service, while still allowing the specific negotiation required for such agreements. He stated the Company's proposal is to add the following language to Rate QF, the end of Special Terms and Conditions 8, Exhibits A and B, to the end of Section 8 for Parallel Operation for Qualifying Facilities, and to the end Section 13 for Parallel Operation for Qualifying Facilities: "..., and modified, as necessary, to fully comply with all IURC and PURPA requirements."

iv. **Commission Discussion and Findings**. The evidence demonstrates that the provision of standby services is highly contingent on the specific circumstances of the customer and the Company, and often requires careful negotiation based on the specific circumstances of the customer. Therefore, we do not believe Rate QF needs to attempt to list all potential contingencies, as the Industrial Group seems to suggest. Nor does the evidence support a conclusion that the lack of such list of all potential contingencies is a violation of PURPA or this Commission's rules. However, we appreciate the Company's proposal to add language to its tariff to affirm that the terms and conditions of backup service may be modified to ensure compliance with all Commission and PURPA requirements. Therefore, we approve of the Company's proposal, as modified by Mr. Bailey's rebuttal testimony and attachments.

d. **Deposit Interest Rate.**

i. **Petitioner's Evidence.** Ms. Quick described the Company's proposal to modify the rate on which customers earn interest on deposits from 6% to 2%. Ms. Quick stated 6% is far above market interest rates, and that 2% is more reasonable given the current interest rate environment. Ms. Quick stated the proposed reduction will benefit all customers, as the use of a 2% interest rate will cause a reduction in the rate associated with customer-provided sources of funds included in the Company's capital structure and weighted average cost of capital calculation used to determine the Company's revenue requirement.

ii. **Industrial Group's Evidence**. No witness opposed the Company's proposal to move the interest rate on customer deposits from 6% to 2%. However, Industrial Group witness Dauphinais sponsored Attachment JRD-3, Section 4.4 of which proposed to grandfather in existing customer deposits, such that they will continue to earn interest at six percent even after the interest rate is reduced to 2% in this order. Neither Mr. Dauphinais nor any other witness provided testimony to justify this proposal.

iii. **Petitioner's Rebuttal Evidence**. On rebuttal, Ms. Quick stated that the Industrial Group does not appear to object to the proposal to earn interest at two percent as opposed to six percent. However, she pointed out the Industrial Group seeks to grandfather in existing customer deposits, such that they will continue to earn interest at six percent after the effective date of this order. Ms. Quick explained that a more equitable and administratively efficient handling of existing deposits is that they would earn six percent interest from the date of deposit until the date of this order, and then reduce to two percent.

iv. Commission Discussion and Findings. The Commission's rule governing interest on customer deposits provides that the interest rate will be six percent or such other rate as the Commission may determine following a public hearing. See 170 IAC 4-1-15(f). Based on the evidence submitted, the Commission agrees with the Company's proposal that customer deposits should earn interest at 2%. We believe the 2% interest rate is an equitable balance between providing for a reasonable rate of return to the customer for deposits being held and the cost incurred by all customers for the Company's provision of electric service.

We decline to adopt the Industrial Group's proposal that customer deposits made prior to the effective date of this order continue to earn 6%, and customer deposits made after to the effective date of this order earn 2%. The Industrial Group did not provide any testimony justifying this approach, and there seems to be none. However, the proposal would place an administrative burden on the Company to keep track of the nuances of each customer deposit, which is not justified. We agree with the Company that a more equitable and administratively efficient handling of existing deposits is that they would earn six percent interest from the date of deposit until the date of this order, and they all reduce to two percent after the effective date of this order. We approve the Company's proposal for these reasons.

e. Petitioner's Request for Waiver of On-Site Premises Visit ~~Call/Text Disconnection Program~~.

i. Petitioner's Evidence. Company witness Quick described the Company's proposal for a waiver from the Commission rule requiring, prior to disconnection of electric service, the Company to make an on-site premises visit. Ms. Quick stated the Company is proposing, instead of a premises visit, to call and/or text notification to such customers both the day before and the day of a prospective disconnection. She stated if the customer is considered a "sensitive" or "essential" customer, or is on the Company's Medical Life Support Program, the Company will still make personal contact on the premises both two days in advance of and on the day of disconnect. Ms. Quick said that because AMI will be fully deployed by the date of this order, remote disconnections are available for the vast majority of customers. On cross-examination, Ms. Quick described that a customer has the ability to provide a third-party notification on its account, which adds a layer of protection for customers. In response to Commission inquiry, Ms. Quick stated the Company was not opposed to communicating to customers if the Commission were to provide a waiver of the premises visit. Tr., p. D-86.

The Company believes, and the data demonstrates, that enhanced communications such as call or text will result in more customers receiving actual notice of a potential disconnection. Ms. Quick explained that in March 2018, the Company began a policy of calling and texting customers prior to disconnection, and the percent of disconnections cancelled substantially increased, leading to lower disconnections. Ms. Quick added that while there are no costs related to this program, there will be cost savings associated with not having to make the on premises visits. At the evidentiary hearing, Company witness Graft explained that these cost savings have been rolled into the rate case forecast.

ii. Commission Discussion and Findings.

Duke seeks a waiver of applicable consumer protection rules to allow the Company to utilize its advanced metering infrastructure ("AMI" or "smart meter") for remote disconnections in most circumstances. 170 IAC § 4-1-16(f) states that, prior to disconnection, a Company employee is required to, among other things, make an on-site premises visit. Instead, Duke proposes to continue its new practice which began back in 2018 to call and/or text a customer both the date before and the day of a prospective disconnection.

Although the parties welcomed Duke starting these additional communications back in 2018 to encourage customers of payment to avoid disconnection, they raised several concerns with regard to wholly replacing the on-site premises visit with only these communications. The overarching concern raised at the hearing was that the Commission's consumer protection rules have not been updated since the deployment of AMI. This creates an ad hoc, piecemeal approach across the Indiana electric service territories that is undesirable from the Commission's perspective. This can cause confusion among customers who are treated differently depending on which utility they may have and whether AMI has been deployed. Another concern was that some customers do not maintain phone or cellular service at all, or lose phone or cellular service due to financial hardships, both of which are unaddressed by Duke's plan to perform remote disconnection. As Duke notes, the Company only "has phone numbers for the vast majority of its customers," but not for all of its customers. Petitioner's Ex. 29, p. 26, line 12.

While the Commission appreciates Duke's effort to continue the call and text campaign it implemented back in March 2018, this is no substitute for an on-site premises visit. It is undisputed that there are many critical policy reasons to still conduct the on-site premise visit, even with the availability of AMI to perform remote disconnection, including but not limited to ensuring the resident is safe and providing the resident one last opportunity to pay before loss of this essential human service.

We also note the continued request by certain parties for the Commission to update its consumer protection rules in light of the wider deployment of AMI and AMI's capabilities. Rather than addressing these waiver requests on a case-by-case basis, we will open up a rulemaking in the near future, and will address the issue then. In the meantime, Duke shall continue to comply with the requirements in 170 I.A.C. § 4-1-16(f).

~~170 IAC 4-1-16(f) provides that prior to disconnection of electric service, a Company employee is required to, among other things, make an on-site premises visit. The undisputed evidence presented in this case reflects that notification by call or text decreases disconnections by increasing actual notice by customers of prospective disconnection. The evidence also showed the Company is continuing protections for sensitive or medically essential customers, and allow for third-party notifications for customers. Based on the evidence presented, we approve of the requested waiver of the requirement of an on-site premises visit prior to disconnection. However, as invited by the Company, we do require the Company communicate to customers regarding the Commission's waiver of the premises visit being approved in this order~~ .

18. Other Issues.

a. Two-Step Rate Increase.

i. Petitioner's Evidence. Company witness Douglas testified about Duke Energy Indiana's proposed two-step base rate increase procedures. She testified that, because base rates in this proceeding are calculated based on forecasted rate base at the end of the test period (December 31, 2020), the Company proposes to implement the requested rate increase in two steps to reasonably reflect the utility property that is used and useful at the time rates are placed in effect. Specifically, the Company proposes a two-step adjustment in rates that will utilize the Company's existing Rider 67 (the Credits Rider). As proposed by Ms. Douglas, Step 1 will adjust rates when new base rates are implemented, expected to occur in mid- 2020, the middle of the test period, following the Commission's issuance of its Order in this proceeding. Upon receipt of the Order, the Company proposes to file and implement the base rates supported by Duke Energy Indiana witnesses Mr. Jeffrey R. Bailey and Mr. Flick, if approved, or as adjusted if required by the Commission's order. These rates will be left in place until new rates are approved in the Company's next retail rate proceeding. These base rates will be based on the forecasted test period 2020, including forecasted plant and property which may not have been completed or be in-service to customers at the time of the Step 1 increase. Accordingly, Ms. Douglas testified, the rates will likely require an adjustment using the Credits Rider (Rider 67) to be sure that only rate base that is in-service at the end of 2019 will be included in the Step 1 rates. She stated that the Company will implement an adjustment using the Credits Rider to reflect revised revenue requirements using year-end 2019 actual value of net plant and property -- so long as the 2019 actual value of net plant and property does not exceed the forecasted 2020 values that were included in the Commission approved rates. Further, she stated, these adjusted revenue requirements will also adjust the depreciation expense and include the 2019 actual capital structure and cost of capital values in the calculation. In this way, she testified, the combination of the base rates plus the Credits Rider Step 1 rate adjustment will reasonably reflect actual used and useful plant-in-service as of the Step 1 timing of implementation of the base rates, while aligning both the depreciation calculation and the capital structure with the plant-in-service amount included in rate base.

Ms. Douglas testified that the Step 2 rate increase will adjust rates after the end of the test period, *i.e.*, after December 31, 2020, to reflect December 31, 2020 net plant and property amounts in-service at that point and included in the Commission approved base rates. She explained that, so long as the total revenue requirement amounts using actual December 31, 2020 net plant and property, depreciation and capital structure and cost of capital amounts do not exceed the forecasted 2020 values that were included in the Commission approved rates, the Step 1 Credits Rider rate adjustment will be modified to reflect the revenue requirements using the actual December 31, 2020 plant and property values. But, she stated, if the revenue requirements using the actual December 31, 2020 plant and property values are higher than the revenue requirements the Commission approved in base rates, no ongoing credit adjustment to base rates will be required, and the Step 1 Rate Adjustment component of the Credits Rider will be adjusted to zero following a compliance filing. Under either scenario, she explained, the Credits Rider will be adjusted from the amount included in Step 1 rates via a compliance filing as soon as practicable after year-end results become available, expected to be sometime during the first quarter of 2021. In this way, the combination of the base rates plus the Credits Rider Step 2 rate adjustment will reasonably reflect actual used and useful plant-in-service as of the December 31, 2020 test period end date, while aligning the depreciation calculation with the plant-in-service amount included in rate base and keeping the capital structure aligned with the same timing as the rate base, until new base rates are approved in the Company's next retail base rate case.

ii. <u>OUCC's Evidence</u>. OUCC witness Blakley addressed the Company's proposed 2-step rate increase procedures. He indicated that the OUCC generally agrees with Duke Energy Indiana's proposed Step 2 methodology, but with the additional requirement that the OUCC and intervenors will have 60 days from the date of verification of actual used and useful property to state objections to Duke Energy Indiana's verified actual test-year end net plant. If there are objections, the Commission should establish a hearing to determine the Company's actual test-year end net-plant. He further recommends that the Step 2 rates be trued-up (with carrying charges) retroactive to January 1, 2021 (regardless of when Step 2 rates go into effect.)

iii. <u>Petitioner's Rebuttal Evidence</u>. Ms. Douglas responded to Mr. Blakley's proposal to inject additional time into the schedule before the Commission reviews and approves the final rates (particularly if the parties object and a hearing is required to be scheduled, as under the OUCC proposal). She noted that this proposal has the potential to unreasonably delay implementation of final rates to the harm of the customers or the Company, depending on the differential between Step 1 rates and Step 2 rates. She noted, however, that the OUCC's proposal that, in addition to the extra time in the schedule, rates be trued-up with carrying charges back to January 1, 2021, regardless of when the Step 2 rates are approved by the Commission, helps remedy this delay and is something the Company would be amenable to. In fact, she stated, it appears to be good regulatory policy and a fair and reasonable way to ensure that final rates in a proceeding that uses a forecasted test period can be implemented shortly after the close of the test period -- albeit, via a later reconciliation rather than directly -- while providing adequate review time for the final rates.

She concluded that the Company is agreeable to the OUCC's proposed 60-day review period if the Commission approves the OUCC's proposal to make the Step 2 rates effective January 1, 2021 via a true-up with carrying costs. She also offered that, alternatively, the Step 1 credit could be removed from Rider 67 effective January 1, 2021, so that the only true-up needed would relate to the rate differential arising between the actual and forecasted 12/31/2020 plant and capital structure values rather than the difference between the Step 1 and Step 2 rates. The Rider 67 credit would then be replaced if needed with the final approved Step 2 credit, with a subsequent true-up with carrying costs. She testified that under either such alternative (leaving the Step 1 credit in Rider 67 until Step 2 rates are implemented and then trueing up or removing the Step 1 credit effective January 1, 2021, until Step 2 rates are finalized and then trueing up), the Company would propose the true-up and carrying costs be included in Rider 67 in the next subsequent Rider 67 filing to be filed mid-2021, reconciling 2019 revenues.

iv. <u>Commission Discussion and Findings</u>. We appreciate both the Company's and the OUCC's proposals designed to ensure that rates are ultimately implemented in a full and timely manner while also ensuring that the base rates only reflect plant and property that is actually in-service and used and useful at the end of Step 1 and at the end of Step 2. We find that the Company should implement its Step 1 and Step 2 rate increases, as outlined in Ms. Douglas' testimony, but with the additional requirement proposed by Mr. Blakley, giving the OUCC and intervenors 60 days from the date of verification of actual used and useful property to state objections to Duke Energy Indiana's verified actual Step 2 test-year end net plant. If there are objections, the Commission can hold a hearing, if necessary, to determine the Company's actual test-year end net-plant. Further, we find that the Step 2 rates shall be trued-up (with carrying charges) retroactive to January 1, 2021, regardless of when Step 2 rates go into effect.

b. Accounting Requests.

i. Edwardsport Outage Deferral Request.

(A) Petitioner's Evidence. Petitioner's witness Davey indicated the Company is seeking cost deferral for the 2020 Edwardsport IGCC major planned maintenance outage, which outage will occur every seven years at an estimated expense of approximately $46.4 million. The Company proposes to include one-seventh of this expense in rates and defer the remaining expenses until the amount billed in rates cumulatively exceeds $46.4 million. If the amount billed in rates cumulatively exceeds $46 million, Mr. Davey said Petitioner proposes to establish a regulatory liability.

Duke Energy Indiana witness Gurganus provided more information on the Edwardsport planned major outage in his testimony. He testified the Edwardsport Station's 2020 outage has an O&M budget of $46.4 million. Mr. Gurganus stated the Company would receive operational benefits from the first major outage at Edwardsport, which would allow the Station to identify and correct issues during a planned outage that would necessitate multiple pieces of equipment being offline, improving the Station's reliability. He added the period of gasifier unavailability will allow for a thorough cleaning of the radiant syngas cooler tubes, which will help increase the HP steam flow to the steam turbine.

Mr. Gurganus indicated the Company worked closely with the regional project engineering group and developed a seven-year outage cycle, which he stated would optimize the amount of generation that is being provided to the grid by the fleet while maximizing the output of the Station. According to Mr. Gurganus, the seven-year outage cycle will permit several major components to be tracked and addressed, including the gasifier refractory replacement, combustion turbine inspections and steam turbine inspections.

Mr. Gurganus said Duke Energy Indiana understands that building the full amount of the 2020 outage expense into base rates does not make sense given that it will only occur approximately every seven years. That fact led the Company to propose the inclusion of 1/7th of the planned maintenance cost into base rates—meaning the Company will recover the costs of the 2020 outage over the following seven years.

Petitioner's witness Douglas also testified on this issue. She sponsored Exhibit 4-E (DLD) Schedule OM16, which normalized the Edwardsport planned outage expenses and removed $46,401,000 from test period production maintenance costs for the incremental cost of the first major outage planned for the spring of 2020 at the Edwardsport Station. She testified the additional maintenance cost is not representative of an ongoing level of maintenance cost at the station and, therefore, the cost would be deferred in a major planned outage reserve account and amortized over seven years. Ms. Douglas added that while $46.4 million was removed for setting base rates because the costs weren't reflective of an ongoing yearly level of planned outage maintenance expense, they are reflective of the level of reasonable and necessary incremental planned outage maintenance expense that will occur at Edwardsport approximately every seven years.

Ms. Douglas indicated the retail portion of the production maintenance expense that is actually incurred for the 2020 spring major planned outage in excess of the remaining (after the *pro forma* adjustment) $4,730,902 amount included in base rates for ongoing Edwardsport planned maintenance expense up to the $46,401,000 forecasted amount be deferred in a regulatory asset account for amortization and cost recovery over seven years. In this way she asserted the revenue requirements for customers will be smoothed out, and the Company will be able to recover its reasonable and necessary maintenance costs for serving customers. She added the Company is not requesting carrying costs in rate base, just deferred recovery of the expenses over time. Ms. Douglas noted the Company's proposed base rates include a forecasted amount of amortization ($6,629,000) for the Edwardsport major planned outage reserve. She concluded this portion of her testimony by stating the Company's proposal provides a balanced way to afford the Company the opportunity to recover the reasonable and necessary costs of the 2020 major planned outage, while avoiding customer rate volatility by recovering the costs over time.

(B) **OUCC's Evidence**. Mr. Kollen recommended the Commission limit deferrals for the test year Edwardsport Station major maintenance outage expense to the actual expenses incurred or the estimated $46.4 million, whichever is less.

(C) **Petitioner's Rebuttal Evidence.** Company witness Douglas testified in rebuttal to OUCC witness Kollen's recommendation that the Edwardsport 2020 major outage expense deferrals be limited to the lower of actual costs incurred or the Company's $46.4 million forecasted amount. Ms. Douglas indicated the Company is amenable to limiting the deferrals for the 2020 Edwardsport major outage to the lower of actual costs incurred or the $46.4 million forecasted amount as recommended by the OUCC. She also noted the actual amount of the 2020 Edwardsport outage will be known by the time Step 2 rates are finalized.

(D) **Commission Discussion and Findings.** We note that no party objected to the Company's request and as such based upon the foregoing evidence on this issue, we find that it is reasonable and appropriate to amortize the Edwardsport 2020 major outage expense over seven years and to limit the resulting deferrals to the lower of the actual costs incurred by Duke Energy Indiana or the $46.4 million forecasted amount.

ii. **Customer Connect Deferral Request.**

(A) **Petitioner's Evidence.** Mr. Davey briefly summarized the Company's proposed cost deferral for Customer Connect, a new Duke Energy Indiana customer service platform to be operational in late 2022. He indicated the enterprise-wide estimated cost of Customer Connect is $900 million and the amount allocated to Duke Energy Indiana is estimated at $90-95 million, with approximately 50 percent reflecting the capital investment and the remainder, O&M. Mr. Davey testified the Company's proposal is to defer these costs with carrying costs until the Company's next retail rate case in which they will be recovered.

Duke Energy Indiana witness Graft elaborated in her testimony regarding the proposed ratemaking treatment for the Customer Connect project. She said the Company has requested deferral of depreciation expense and post-in-service carrying costs at the weighted average cost of capital rate as regulatory assets until the related assets are deemed to be used and useful in a future rate case. The Company has also requested deferral of O&M and payroll tax costs incurred from 2018 and forward associated with development and implementation of the Customer Connect project, with carrying costs at the weighted average cost of capital rate, as regulatory assets to be held for recovery in a future rate case. The Company removed O&M and payroll taxes from the forecast test period and is instead seeking deferral with carrying costs.

(B) **OUCC's Evidence.** Mr. Kollen recommends the Commission deny deferral of O&M incurred prior to the date new base rates are implemented in this proceeding, but recommends the Commission allow deferral on a going forward basis, without carrying costs, of O&M incurred after the date new base rates are implemented in this proceeding and until the Customer Connect project is placed in service. He also recommends denial of the Company's request to defer depreciation expense and post-in-service carrying costs.

Mr. Kollen argues the Company should not be allowed to defer previously incurred costs for future recovery upon implementation of new base rates in this proceeding because it would have a positive earnings impact in 2020 and in future years when rates are implemented recovering the deferred costs. He asserts that deferred depreciation, carrying costs on deferred O&M, and post-in-service carrying costs are unnecessary given there is no offset for the effect of declining rate base between rate cases.

(C) **Industrial Group's Evidence.** Mr. Gorman recommends the Commission deny the Company's Customer Connect deferral request in its entirety. He suggests the Company seek rate recovery of the Customer Connect project and associated costs after implementation is complete. He expresses concern the Company has not proposed a cap on the capital portion of the Customer Connect investment and that without ongoing review, customers would ultimately pay more for the project under the Company's deferral proposal than if the Company sought cost recovery after the project is in service. He asserts the Company has not provided sufficient information to support Commission approval of its CPCN request and in his opinion no legal basis exists to support the creation of regulatory assets associated with utility plant that is not yet in service.

(D) **Petitioner's Rebuttal Evidence.** Duke Energy Indiana witness Graft testified the Company is not requesting a CPCN for the Customer Connect project, and no statutory authority exists for the Commission to issue a CPCN for these costs. Ms. Graft indicated that is why the Company is requesting deferral accounting authority in the context of this rate case.

Ms. Graft stated the Company agrees in concept with Mr. Kollen's recommendation to only seek deferral of its O&M and payroll tax costs on a going forward basis. However, she stated the Company defines going forward as 2019 and forward, not just from the date of implementation of new base rates in this proceeding and forward as Mr. Kollen proposed. Therefore, Ms. Graft indicated the Company is willing to forego recovery of its 2018 O&M and payroll tax costs of approximately $2.1 million for the Customer Connect project.

Ms. Graft clarified in rebuttal that the Company is still seeking authority to defer carrying costs on the deferred O&M and payroll tax costs as a regulatory asset to be held for recovery in a future rate case, as well as authority to defer depreciation and post-in-service carrying costs as regulatory assets until the related assets are deemed to be used and useful in a future rate case. She noted the Company is requesting this accounting treatment in order to be made whole for this important investment that will help it better serve its customers. Ms. Graft added that only approximately $1.1 million of net plant in service (approximately $2.3 million of plant in service net of approximately $1.2 million in accumulated depreciation) has been included in rate base for Customer Connect in the forecast test period.

According to Ms. Graft, Mr. Kollen's argument that Commission approval of the Company's deferral proposal would have a positive earnings impact in 2020 and in future years when rates are implemented recovering the deferred costs ignores the negative impact to earnings in the years the deferred costs were incurred without any associated rate recovery or assurance of future rate recovery. She claimed Mr. Kollen's assertion that deferred depreciation, carrying costs on deferred O&M, and post-in-service carrying costs are unnecessary given there is no offset for the effect of declining rate base between rate cases does not consider the fact that the Company's current customer information system has been fully amortized for some time.

Therefore, Ms. Graft indicated the Company's proposed base rates in this proceeding include very little for a return on and a return of its investment in a customer information system: an annual return on investment of approximately $65 thousand (associated with the approximately $1.1 million of net plant in service in the forecast test period) and an annual return of investment via amortization expense of approximately $0.6 million (associated with the approximately $2.3 million of gross plant in the forecast test period). Ms. Graft contended the Company should not have to absorb the capital and O&M expense associated with a project of this magnitude that is being implemented over several years, which is why it is seeking the requested deferral accounting authority.

Finally, Ms. Graft noted the Commission, OUCC, IG, and all interested parties will have the opportunity in a future base rate case to review the deferred costs to ensure they are reasonable, necessary, and prudently incurred. She concluded it is reasonable for the Company to request and for the Commission to approve deferral treatment associated with the Customer Connect project that will simplify, strengthen, and advance its ability to serve customers, all of which are a priority to the Company and the Commission.

(E) **<u>Commission Discussion and Findings</u>.** IG witness Gorman asks the Commission to deny the Company's Customer Connect deferral request in its entirety but in part because he contends the Company has not provided sufficient information to support approval of a CPCN request associated with utility plant not yet in service. In its rebuttal, the Company made clear that it is not requesting a CPCN for the Customer Connect project. Therefore, based upon the foregoing evidence, we find that compliance with the requirements for granting a CPCN is not an issue with respect the Company's Customer Connect deferral request and provides no basis for us to deny the request.

OUCC witness Mr. Kollen recommended denial of the Customer Connect deferral request in part. In rebuttal, Company witness Ms. Graft agrees in concept with his recommendation to only include in the deferral O&M and payroll tax costs on a going forward basis, however, she clarified the Company's position that going forward means 2019 and forward. As a result, Company witness

Ms. Graft indicated that Duke Energy Indiana is willing to forgo recovery of its 2018 O&M and payroll tax costs of approximately $2.1 million.

Duke Energy Indiana is still seeking authority from the Commission to defer the carrying costs on the deferred O&M and payroll tax costs as a regulatory asset to be held for recovery in a future rate case, as well as authority to defer depreciation and post-in-service carrying costs as regulatory assets until the related assets are deemed to be used and useful. After considering the respective positions of the parties on this issue as summarized above, the Commission finds that the Company's request for approval of the Customer Connect deferral, as modified, should be granted. We are convinced on the weight of the evidence that the deferral treatment associated with the Customer Connect project that we have approved will simplify, strengthen, and advance the ability of Duke Energy Indiana to serve its customers.

iii. Major Storm Damage Restoration Reserve.

(A) Petitioner's Evidence. Duke Energy Indiana witness Sieferman testified that the Company proposes to establish a Major Storm Reserve with a base level of $12.7 million, the amount proposed by the Company to be built into base rates. The Company would track differences between the actual operating costs incurred and the amount collected in base rates, with any under- or over-recovery recorded to a Regulatory Asset or Regulatory Liability account, respectively. The regulatory treatment of the net Major Storm Reserve amount would be addressed as part of the Company's next retail base rate case. Ms. Sieferman explained that it was appropriate to establish a Major Storm Reserve as the timing, frequency, and costs for major storms are unpredictable and therefore challenging for the Company to establish a precise amount in base rates. She indicated the Company's proposal is reasonable and balances the interests of both the Company and its customers by smoothing out these costs and providing for the Company to recover no more or less than its actual costs.

Company witness Hart provided testimony related to the Company's major storm expenses over the past five years (2014-2018). She stated that actual expenditures will vary year to year based on the actual number of major storms and the types of restoration required. Based upon the trend in rising storm costs and the variability and unpredictability of annual MED storm level amounts, Ms. Hart testified Duke Energy Indiana believes it is appropriate to establish an MED storm level amount in base rates and then establish a reserve for any amounts below or above that level.

(B) OUCC's Evidence. Mr. Alvarez testified for the OUCC and suggested the Commission should deny the Company's request for a Major Storm Reserve unless the Company agrees to develop an operational plan to manage storm restoration activities. Mr. Alvarez recommends this operational plan should be integrated within the vegetation management and TDSIC programs. Assuming the Company agrees to develop the operational plan he suggests, Mr. Alvarez agrees with the Company's proposal to establish a Major Storm Reserve, but suggests the base level should be set at $6.0 million instead of $12.7 million. In the event the Company does not agree to establish Mr. Alvarez's new operational plan, or if the Commission denies the Company the authority to establish a Major Storm Reserve, Mr. Alvarez recommends that $5 million be embedded in base rates to represent an ongoing level for major storm expenses.

(C) Petitioner's Rebuttal Evidence. Company witness Hart responded in rebuttal to OUCC witness Mr. Alvarez's recommendations. She stated Mr. Alvarez's testimony is incorrect and unreasonable and that Mr. Alvarez claims that Duke Energy Indiana's storm response has been imprudent, without any supporting evidence. Ms. Hart stated that she has been involved with the Company's storm response efforts for seven years and can attest that the Company's efforts are robust, efficient, and proactive. She testified that there are many problems with Mr. Alvarez's suggestion that the Company follow his recommended operational plan, including that the Company already has distinct workstreams and teams responsible for major storm response, vegetation management and TDSIC and that these teams collaborate frequently, when appropriate. In conclusion, Ms. Hart said the Company could not give the OUCC's position any consideration because Mr. Alvarez provided nothing but conjecture and insinuation and, therefore, the Commission should reject his proposal.

Duke Energy Indiana witness Sieferman also responded in rebuttal to OUCC witness Mr. Alvarez's testimony in this area. She explained Mr. Alvarez's recommended $6 million level for the Major Storm Reserve appeared to be arbitrary and not supported by evidence. She stated the costs to restore service after major storms are both unpredictable and vary significantly year-to-year.

In addition, Ms. Sieferman further testified the Commission has approved similar Major Storm Reserve concepts for use by other Indiana electric utilities in recent base rate case proceedings. She noted Indiana Michigan Power Company was granted approval for a Major Storm Restoration Reserve in Cause No. 44075 and again in Cause No. 44967. She said the Commission also approved the creation of a Major Storm Damage Restoration Reserve for Indianapolis Power & Light Company in Cause No. 44576 and again in Cause No. 45029.

Finally, Ms. Sieferman stated Mr. Alvarez acknowledged the proposed reserve accounting balances customer and utility interests by providing a way for customers to pay no more (or less) than what the Company incurs for such restoration efforts and allows the Company an opportunity to potentially recover prudently incurred costs necessary to timely restore power after significant storms if that level exceeds what is built into base rates. She indicated storm restoration costs are volatile and highly dependent on storm events and therefore largely outside the Company's control. A Major Storm Reserve recognizes the difficulty with estimating this cost item, while assuring recovery of prudent costs.

(D) Commission Discussion and Findings. The Commission has approved major storm reserve ratemaking concepts like that proposed by Duke Energy Indiana for use by other Indiana electric utilities in recent base rate case proceedings. For instance, we authorized Indiana Michigan Power Company to implement a Major Storm Restoration Reserve in Cause No. 44075 and again in Cause No. 44967. We also approved the creation of a Major Storm Damage Restoration Reserve for Indianapolis Power & Light Company in Cause Nos. 44576 and 45029.

In *Re Indiana Michigan Power Company*, Cause No. 44075 (approved February 13, 2013) at 73, we discussed the benefits of the major storm reserve approach, noting: "the proposed accounting treatment will smooth out the impacts of major storms, thereby mitigating the financial consequences of a major storm." We further noted that if the "amount of imbedded storm damage expense exceeds the actual expense incurred, ratepayers will receive the benefit of the overpayment." *Id.* We continue to find that the use of the major storm reserve concept is an appropriate approach to account for major storm costs.

Based upon substantial evidence of record provided by the Company and our experience with the regulation of other Indiana electric utilities which have experienced storm damage costs, we find that the Company should be authorized to set the base level for the Major Storm Reserve at the five-year historical average annual amount of $12.7 million and the Company should track any differences between the operating costs incurred and the amount collected in base rates. Any under- or over-recovery in such costs then would be recorded to a Regulatory Asset or Regulatory Liability account, respectively. Finally, we conclude the regulatory treatment of the net Major Storm Reserve amount should be addressed as part of the Company's next retail base rate case.

iv. Pension Settlement Deferral Request.

(A) Petitioner's Evidence. Ms. Douglas explained that pension settlement accounting, which is prescribed by U.S. GAAP accounting in certain situations, results in an acceleration of recognition of the settled portion of gains or losses currently deferred in a pension regulatory asset on the Company's accounting books. Absent triggering settlement accounting, these gains or losses would be amortized as a portion of net periodic pension cost, over the average remaining service period of active participants. If settlement accounting is triggered for regulated entities, the losses on the settled portion of the net periodic pension obligation must be reflected as an expense immediately, unless it is probably the costs (the amortization of which are currently a portion of pension cost being recovered through rates) will be recovered from customers. Ms. Douglas explained that the Company proposed that the settled portion of the losses be moved to a separate regulatory asset account and continue to be amortized over the average remaining service period of the pension plan participants. She stated that this GAAP required settlement accounting does not increase pension cost to the Company or to customers – it just accelerates the recognition of it on the Company's accounting books, reducing the original cost in the pension asset and future benefit costs from the actuarial study. Under the Company's requested accounting deferral treatment, she explained that annual pension costs would remain basically the same and that without the Commission's approval of this accounting treatment, the Company would incur earnings erosion and volatility, rather than the smoothing of these reasonable and necessary pension costs over time that normal pension accounting treatment affords.

Mr. Setser testified that settlement charges incurred by Duke Energy Indiana because of the triggering of settlement accounting will be deferred as a regulatory asset and amortization expense of the settlement charge will be recognized over the average remaining service life of Duke Energy Retirement Cash Balance Plan participants, currently 9.75 years.

(B) OUCC's Evidence. Mr. Kollen testified for the OUCC on this issue. He recommended the Commission reject the Company's request to retroactively defer the costs since in 2019 until base rates are reset in this proceeding. Mr. Kollen also argued that a deferral will harm customers and will allow the Company to record a windfall to income in 2020 in exchange for harming customers in the form of increased customer rates when base rates are reset in the next base rate case proceeding.

(C) Petitioners' Rebuttal Evidence. Mr. Setser testified for the Company on rebuttal and clarified that the Company is not asking for retroactive treatment in this proceeding. He stated these costs are already deferred costs following the guidance of SFAS 158, codified in ASC715. He noted that under ASC Topic 715, Duke Energy is required to recognize as a component of other comprehensive income, the net actuarial gains or losses and prior service costs or credits that arise during the year but are not recognized as components of net periodic benefit cost of the period ("Unrecognized Gains or Losses"). Unrecognized Gains or Losses related to the Company's regulated operations are recorded pursuant to ASC Topic 980 and are reflected in regulatory assets or regulatory liabilities, subject to the regulatory treatment of such costs for the regulated jurisdiction. Unrecognized Losses are recorded to FERC account 182.3 (Other regulatory assets) while Unrecognized Gains are recorded to FERC account 254 (Other regulatory liabilities). The Unrecognized Losses recorded to FERC account 182.3 are commonly referred to as the "SFAS 158 Regulatory Assets."

Mr. Setser further stated the recognition of the SFAS 158 Regulatory Asset complies with FERC guidance per Docket No. AI07-1-000 (March 29, 2007). He also said that GAAP accounting rules for pensions require the Company to accelerate the recognition of these expenses when a settlement event occurs. He noted that Duke Energy Indiana's proposal is simply to continue to defer these costs and recognize them in a manner consistent with how these costs would otherwise be recognized. He concluded his rebuttal on this issue by stating the Company is being proactive in identifying that these settlement events will reoccur in future years and will result in "lumpy" expense recognition if the requested deferral is not approved.

(D) Commission Discussion and Findings. We find the Company's evidence persuasive that GAAP accounting rules for pensions require the Company to accelerate the recognition of these expenses when a settlement occurs. We agree the Company is being proactive in identifying that these settlement events will reoccur in future years and will result in "lumpy" expense recognition if we do not approve the requested deferral. Accordingly, we find that Duke Energy Indiana should continue to defer these costs and recognize them in a manner consistent with how these costs would otherwise be recognized.

v. Incremental Vegetation Management Deferral Request.

(A) Petitioner's Evidence. Ms. Graft testified that Petitioner is seeking the deferral and amortization over three years of forecasted distribution vegetation management O&M costs incurred in 2020 in excess of the amount in current base rates for the period before the Company's revised base rates are implemented.

(B) OUCC's Evidence. OUCC witness Mr. Kollen testified the Company is seeking to increase its distribution vegetation management O&M in 2020 by $18.470 million annually, calculated by doubling the $9.235 million deferral requested by the Company. He suggests the Company can avoid the need to request a deferral by simply waiting to increase its vegetation management activities to align more closely with when it expects base rates proposed in this proceeding to be effective. Mr. Kollen asserts that if the Commission allows a deferral, it should be for $5.240 million, which represents half of the total *pro forma* increase to test period expense Petitioner proposed.

(C) **Industrial Group's Evidence**. Mr. Gorman testified for the IG and also opposed the Company's proposal to defer forecasted distribution vegetation management O&M. He argues that a utility must manage its O&M between rate cases and that the Company could have timed its rate case differently if it wanted to be able to recover its proposed level of distribution vegetation management O&M via new base rates beginning in January 2020.

(D) **Petitioner's Rebuttal Evidence**. Ms. Graft stated in rebuttal that Mr. Kollen's assumption that vegetation management costs are spread evenly over the year is incorrect. The Company's proposed distribution vegetation management O&M is $49 million, comprised of $38.9 million in the test period forecast, plus a $10.5 million *pro forma* adjustment. She said the proposed deferral amount simply represents the difference between forecasted distribution vegetation management O&M in excess of the amounts in current base rates for the January to June 2020 period before base rates proposed in this proceeding will be effective. Finally, she noted an effective vegetation management program is an important initiative to the Company, its customers, and the Commission and, therefore, it is reasonable for the Company to request and for the Commission to approve deferral treatment associated with the incremental costs the Company is incurring by moving to a five-year trim cycle for enhanced safety and reliability of the distribution system.

As an alternative, Ms. Graft suggested should the Commission desire to utilize the cumulative reserve accounting approach, the Company could incorporate its proposed deferral for January through June 2020 within the cumulative reserve and then any balance remaining in the reserve account would be addressed in the Company's next retail base rate case.

If the Commission were to approve this approach, Ms. Graft stated the result would be a reduction in test period amortization expense of approximately $3.1 million (equal to the deferral request of $9.235 million divided by the proposed three-year amortization period).

(E) **Commission Discussion and Findings.** Having reviewed the evidence, we agree that Petitioner should be authorized to defer vegetation management O&M costs incurred in excess of the amount in current base rates from January 1, 2020 through the date base rates are implemented in this proceeding. The Company has put forth a plan to increase its vegetation management trim cycle and commence its activities on January 1, 2020; therefore, it is appropriate to approve this deferral request. We authorize the Company to amortize this deferral in its base rates over three years as it has proposed.

vi. **316(a) and 316(b) Deferral Request**.

(A) **Petitioner's Evidence**. Mr. Mosley testified the Company has requested recovery through the ECR Rider of its prior expenses related to 316(a) and 316(b) studies that it previously deferred on its books. He indicated that in the Company's last rate case $30,000 in annual compliance expenses were built into base rates. However, starting in 2018, there have been two demonstration studies required during NPDES permitting. Mr. Mosley's testimony describes the federal mandate, the federally mandated compliance projects, and how the projects will help Duke Energy Indiana comply with the federal mandate.

Ms. Graft also testified on this issue. She said the Company is requesting timely recovery of 80% of the retail portion of the 316(a), 316(b), and NPDES program study costs that must be expensed through the consolidated Rider 62. The Company is requesting to defer the 20% of the retail portion of the 316(a), 316(b), and NPDES program study costs that must be expensed as a regulatory asset with carrying costs at the weighted average cost of capital for recovery in a future rate case.

In addition to seeking to recover the costs of these two studies, Mr. Mosley indicated the Company requested the authority to defer its future 316(a), 316(b) and NPDES compliance related expenses for future recovery in its ECR. To the extent that future studies are required by NPDES permits, then the expenses of those studies presumably would be similar to those already seen at Noblesville and Cayuga. Mr. Mosley stated Duke Energy Indiana commits to filing a separate proceeding under the Federal Mandate statute should compliance projects be identified as part of the studies being performed for NPDES permit renewals. He added that the Company would also keep the Commission up to date on the 316(a) and 316(b) studies through its semi-annual ECR proceedings.

(B) **OUCC's Evidence**. Ms. Armstrong argues in her testimony that the Commission should not approve Duke Energy Indiana's request to defer its 316(a), 316(b) and NPDES-related compliance costs based on the contention that the Company did not comply with the federal mandate statute and get preapproval from the Commission prior to incurring them. She also argues that the future federally mandated 316(a) and 316(b) study costs the Company is seeking preapproval of should be denied as too uncertain. In addition, she asserts that the 316(a) and 316(b) costs are too small to include in future ECR proceedings and that it would be administratively burdensome to review them.

(C) **Petitioner's Rebuttal Evidence**. Duke Energy Indiana witness Ms. Graft testified on rebuttal that the Commission did preapprove for timely recovery the 316(a) and 316(b) study costs. In Cause No. 44418, Ms. Graft said the Company specifically requested timely recovery of such future plan development costs "associated with future environmental planning for compliance with air, water, or waste regulations via Rider 71 (or via Rider 62 to the extent such costs are related to a capital project)." Cause No. 44418, Petitioner's Exhibit F at 9-10. Ms. Graft indicated the Order in that proceeding authorized timely recovery of "future plan development, preliminary engineering, testing, and pre-construction costs via Rider 62 and/or 71." 44418 Order at 29.

Subsequently, in Cause No. 44765, she noted Duke Energy Indiana sought and received Commission approval to recover its plan development, preliminary engineering, testing, and pre-construction costs and cited the preapproval from Cause No. 44418 in its testimony in that proceeding. Cause No. 44765, Petitioner's Exhibit 6 at 5-6. She further indicated Duke Energy Indiana also has been recovering those expenses through its ECR rider (Rider 62 and/or 71, as applicable). *See*, *e.g.*, Cause No. 42061 ECR 31 Order at 17 ("Petitioner is also authorized to recover in Rider 71 the amortization of CCR Compliance Plan development costs").

(D) **Commission Discussion and Findings.** Based upon the weight of the evidence, we find that it is appropriate to allow the Company to defer its past and future 316(a), 316(b) and NPDES study costs for timely recovery as federally mandated costs in this rate case.

We will also review those expenses as reasonable and necessary when they are presented in the Company's ECR proceedings.

vii. SO_2 Emission Allowance Deferral Request.

(A) Petitioner's Evidence. Duke Energy Indiana proposes to transfer the native SO_2 EAs from the EA inventory account to a new regulatory asset account to be amortized over a twelve-year period. This would allow the Company to recover the costs incurred for these allowances over the remaining useful lives of the associated generating plants. Duke Energy Indiana also proposed to discontinue using Rider 63, and instead include any native allowance consumption expense and gains or losses on the sale of native EAs in its consolidated Rider No. 62.

(B) OUCC's Evidence. Ms. Armstrong testified that the OUCC does not take issue with the Company's native SO_2 allowance inventory costs proposal. She indicated she was aware that Duke Energy Indiana has decreased its use of SO_2 allowances and that unit retirements at the Wabash River and Gallagher Generating Stations, coupled with the installation of SO_2 environmental controls at the Gallagher, Cayuga, and Gibson Generating stations have resulted in the Company emitting less SO_2 over the last several years. In addition, Ms. Armstrong testified the zero-cost SO_2 allowances Duke is awarded each year exacerbate this issue because it lowers the weighted average SO_2 inventory cost, which decreases annual consumption expense and the rate at which Duke Energy Indiana recovers the remaining inventory cost.

Ms. Armstrong stated the Company benefits because it is able to fully recover the costs of more expensive allowances procured prior to the major changes in environmental regulations, unit retirements, and pollution controls impacting the consumption of EAs over the past decade. She indicated that ratepayers benefit from an eventual reduction in the remaining inventory balance, which lowers the return on inventory customers must pay in base rates over what they could expect to pay if the inventory balance was slowly reduced over 40 or more years. However, to reduce further impact of the accelerated recovery of native SO_2 inventory costs, the OUCC recommends that the Commission adopt Mr. Kollen's ratemaking treatment for recovering regulatory assets.

Ms. Armstrong recommends the Commission approve moving the native SO_2 allowance inventory costs into a regulatory asset, which she suggested should be recovered using the levelized-cost recovery method Mr. Kollen proposes for all regulatory assets. She added that Duke Energy Indiana should be required to discontinue tracking EA costs while at the same time selling any excess EAs whenever possible, and pass the proceeds of any such allowance sales through Rider No. 62.

(C) Petitioner's Rebuttal Evidence. Per Ms. Graft's rebuttal testimony, the Company agrees to discontinue tracking of native EA consumption expenses upon implementation of new base rates. However, the Company reserves the right to seek EA tracking in future proceedings if new regulations are enacted or EA expenses become more volatile. With regard to the proposal to recover the regulatory asset using the levelized-cost recovery method, Ms. Douglas testified that, as with other regulatory assets, the Company opposes Mr. Kollen's proposed levelized methodology.

(D) Commission Discussion and Findings. We agree with the Company and the OUCC that moving the native SO_2 emission allowance inventory costs into a regulatory asset is reasonable, and we approve such. For the reasons stated elsewhere in this Order, however, we reject the OUCC's proposed levelized approach for the recovery of this regulatory asset. Instead, we approve the Company's modified proposal to recovery such regulatory asset over a twelve-year period.

c. FAC Issues. Petitioner made several proposals with respect to its FAC processes. Certain intervenors made other FAC-related proposals.

i. Petitioner's Evidence. First, Petitioner proposes two changes to the allocation of fuel costs that occurs in its FAC process (and impacts the sharing in the Rider 70 off-system sales process). The changes relate to the allocations the Company performs in after-the-fact post-dispatch analyses. Mr. Swez testified in support of these changes. He explained that currently the Company economically stacks, on an hourly basis, the demand (load) with available supply resources (actual generator production amounts). He stated that the unit stacking is prioritized based on average production costs, ranked lowest cost to highest cost. He explained that the model economically allocates the average production costs for serving native load. Duke Energy Indiana proposes to change this stacking logic from an average production cost basis to an incremental production cost basis for long-term commitment generating units such as coal-fired and combined cycle natural gas units. The Company would continue to allocate costs for short-term commitment units, such as combustion turbines, on the existing average cost basis. According to Company witness Swez, this incremental cost logic proposed by the Company more appropriately recognizes that the cost of incremental non-native sales is related to the cost of incremental changes in generation output and will better align fuel cost allocation with actual dispatch and commitment operations. In other words, he explained, the Company is proposing this change because the current average cost-stacking logic does not comport with MISO's incremental dispatch logic. He emphasized that the Company is proposing this stacking change only for long-term commitment units because they are committed for, and predominantly serve, native-load customer requirements. He stated that the likely result of this change in stacking logic is that the minimum load block of long-term commitment units will be allocated to native load. He testified that it is appropriate to allocate this cost to native load given that native load will be entitled to the first call on all generation resources, and these units are committed for the benefit of native load. However, he noted, during periods of low native-load demand, when all minimum-load blocks exceed native-load demand, minimum-load blocks would be allocated to non-native sales. He concluded that this proposed incremental cost approach will better align post-analysis results to the actual dispatch logic used by MISO and will more equitably and appropriately allocate fuel costs between native and non-native sales.

In addition, Mr. Swez explained that Petitioner proposes to eliminate the two-pass stacking process and perform the stacking process exclusively in the Real-Time market, because long-term commitment units are unlikely to be entirely allocated to non-native when split into incremental cost blocks. Currently, Petitioner performs a two-pass stacking process, day ahead and real time. According to Mr. Swez, this two-pass process unnecessarily complicates cost allocation. He testified that this change improves native-load resource optionality to respond economically to deviations in real-time load or generation and recognizes the shift of additional no load costs that accompany the transition to incremental stacking.

Petitioner also proposes that the generic purchase-power procedures – the purchased power benchmark – established in Cause No. 41363 be permanently waived upon the effective date of the Commission's Order in this proceeding. Mr. Swez explained that the Company is making this proposal because the benchmark procedures established in Cause No. 41363 are outdated. He testified that the procedures were initiated at a time when the MISO energy market did not yet exist, and purchases were executed on a negotiated bilateral basis. Since then, he noted, the Company has become a full participant in the organized MISO energy market, and the Company purchases all of its energy requirements from the MISO. He stated that as a member of MISO, the Company's generation, along with all generation participating in the MISO day ahead and real-time energy markets, is economically dispatched and the Company's customers have access to all generation resources in MISO to meet their needs. He stated that purchases made from MISO are, by definition, the most economic purchase available to meet customer load. In addition, he testified that the impact of low natural gas prices and increasing renewable energy penetration has had a significant downward impact on the average market price of energy. He observed that these factors suggest that the risks the benchmark was intended to address have been heavily mitigated. Mr. Swez emphasized that this proposal in no way prohibits review of the Company's purchase-power transactions; the Company's purchase-power costs and its offers into MISO will continue to remain subject to review and approval in each FAC filings.

Finally, Mr. Swez discusses the Company's proposal that all PJM charges and credits related to its Madison Generating Station be recovered through, as appropriate, either its FAC Rider, its RTO Rider, or Rider 70. Mr. Swez explained that the reason for this proposal is that the Madison Station is physically located and connected to the PJM transmission grid. Energy from the Station is transferred to MISO using firm transmission service through a pseudo-tie. Because of this configuration period, Duke Energy Indiana receives a settlement statement from PJM for charges and credits related to the Station's firm transmission, congestion and loss charges or credits, etc. He testified that Madison Generating Station is operated for the benefit of Duke Energy Indiana customers, and as such, customers should be appropriately allocated associated revenues and costs. He noted that the unique situation at Madison was simply not envisioned at the time of the Company's last rate case. He stated that the Company's proposed change appropriately modifies cost and revenue tracking. Similarly, Mr. Swez testified, the Company proposes that costs and revenues associated with Madison Station be further modified because of changes to the MISO capacity market. Specifically, he stated that MISO recently received permission from the FERC to modify the way it values capacity resources located outside the MISO footprint. He testified that Duke Energy Indiana and its customers could potentially be subject to a separation of zonal prices between the Indiana Zone 6 and the newly created PJM external zone, and this change could result in a mismatch in funds paid for the capacity obligation versus funds received from the Madison Station. Accordingly, the Company proposes that all capacity revenues and payments be allocated to native customers first, up to the level of capacity charges assigned to native load by MISO. Mr. Swez testified that under this proposal, regardless of the location of assets or source of capacity revenues, no capacity revenues would flow through Rider 70 non-native sharing mechanism until the native load charges have been met. Once that revenue requirement has been satisfied, further revenues from capacity sales and payments will be allocated as non-native margins and shared through Rider 70. If capacity charges for native load exceeds all capacity revenues, the differential will be recovered the same as it is today.

ii. OUCC Evidence. OUCC witness Boerger responded to the Company's stacking proposals. He testified that he agrees with the Company's proposal to eliminate its "two-pass" stacking methodology, noting that it would allow native load customers access to the Company's lowest cost fuel resources as they are ultimately realized in MISO's real-time market.

Dr. Boerger, however, disagreed with the Company's proposal to move to an incremental rather than average cost allocation of no-load fuel costs. He testified that MISO dispatches units based on incremental cost, which is appropriate because that approach will lead to a least cost dispatch. He further testified, however, that changing the Company's stacking does not change MISO's dispatch of its generating units; the Company's proposal changes cost allocations only after the fact. Because there is no change to the manner in which MISO dispatches Duke Energy Indiana's generating units, there is no improvement in efficiency resulting from Duke Energy Indiana 's proposal. Therefore, with no improvement to operational efficiency resulting from Duke Energy Indiana 's proposal, Dr. Boerger stated, the evaluation of its stacking proposal must come down to whether it is fairer for more no-load costs to be allocated to native load customers compared to non-native sales. Based upon his review, he testified, he concluded there is no improvement in fairness resulting from allocating more "no-load" costs to native load customers. He analogized to the allocation of joint, fixed costs incurred in providing utility service, and observed that standard methodology addresses the difficulty of determining which customers are "marginal" by simply allocating on an "average" basis. He contended that the allocation of no-load cost is similar to the problem of allocating all other costs incurred in a utility's operation and, as such, there is no reason to depart from the standard methodology of allocating costs on an average basis.

OUCC witness Eckert recommended continuation of the current agreement allowing the OUCC 35 days to complete its FAC review and file its FAC testimony. In addition, Mr. Eckert testified that the OUCC recommended approval of the Company's request to waive the purchased power benchmark procedures, conditioned on providing the following in its audit package: (1) root cause analysis for forced outages lasting more than 72 hours, and (2) day-ahead offers and real-awards for test days the OUCC requests.

iii. Intervenor Evidence. Industrial Group witness Dauphinais recommended that the Commission reject Duke Energy Indiana's stacking proposal unless the Commission also requires the Company, through its Rider 70, to pass back to its Indiana retail customers 100% of the Indiana share of Duke's non-native sales margins. He noted that the Company's proposal will likely increase native load fuel costs while equally increasing non-native sales margins. He stated that Duke Energy Indiana passes 100% of its Indiana share of native load fuel costs onto its Indiana retail customers through its FAC, but is permitted to retain 50% of the Indiana share of its non-native sales margins. As a result, he testified, the Company's proposed change to its stacking method is self-serving because it shifts fuel costs from non-native sales to native load sales. However, he stated, the impact on Indiana retail customers of this type of maneuvering can be neutralized by moving to 100% allocation to Indiana retail customers of both native load fuels costs under the FAC and non-native sales margins under Rider 70.

As discussed previously, Sierra Club witness Comings testified that losses associated with uneconomic dispatch of coal units, including Edwardsport, should be disallowed from rates. In addition, he testified that the Commission should open an investigation into the self-commitment practice. As support for his position, he offered a (confidential) analysis of the dispatch economics of the Company's largest coal-fired units.

iv. Petitioner's Rebuttal Evidence. In rebuttal, Mr. Swez stated that the Company disagreed with the OUCC and Industrial Group's recommendation to reject its proposed change in stacking allocation. Mr. Swez reiterated that its incremental stacking proposal more reasonably allocates costs between native and non-native load. Mr. Swez explained that for plants with longer minimum run times, such as coal and combined cycle units, the decision to turn on the unit for an economic commitment is made with the viewpoint of achieving a positive margin over at least the unit's minimum run time, typically at least 3 days for long-term commitment generating units. He noted that it is typical for long-startup time units to return more revenue than cost during some hours of the day when they are "in the money," but return less revenue than costs in other hours, where the unit is "out of the money." He stated that as long as the amount of revenue is expected to be greater than variable costs over the entire commitment period of three days in this example, it is considered "in the money" and economic to turn on or run the unit. Mr. Swez explained that the Company's units with longer startup times, the coal and combined cycle units, have minimum run times that are typically longer than the MISO energy market timeframes of 24 hours for the Day-Ahead market, the market that is most often used to commit these units. Simply said, he stated, longer start-up units are expected to make money in some hours and lose money in other hours, with the overall margin over the entire commitment period summing to a positive amount. Mr. Swez explained why no-load costs generally should be excluded when long start-up time generators are allocated to non-native sales. He stated that no-load cost is a fixed cost of operating a generating unit, and it is not possible to generate net positive power without incurring the cost of fuel needed to keep boilers hot and turbines spinning (no-load costs). He noted that non-native sales occur only when generation in excess of what is required to serve native load is available (*i.e.* native load receives first call on all generation). He further stated that MISO dispatches generation based on incremental variable cost and does not generally consider the fixed no-load cost when calculating the locational marginal prices that determine generation revenue. He explained that under the current average cost stacking method, fixed no-load cost is commingled with variable operating cost when units are allocated to non-native sales -- this fixed/variable commingled cost is then matched with revenue received from MISO that excludes the fixed no-load cost. He testified that this can incorrectly cause the margin on a non-native sale to be negative. Mr. Swez emphasized that the assignment of no-load cost to native load follows principles of cost- causation in that the cost is incurred to provide native load with first call on all generation. Essentially, he concluded, the average production cost approach is asymmetrical and only serves to artificially and inaccurately reduce the fuel costs assigned to native rather than assign the costs appropriately. He added that there would still be situations when no-load costs for some long start-up time generating units would be allocated to non-native generation – for example, in hours where the amount of generation needed to serve native load was less than the sum of the minimum loads of the on-line long start-up time generating units. During these hours, he stated, no-load costs would be allocated to non-native generation. He also added that the proposed change in stacking methodology would not affect the fuel cost allocated to native load in every hour; in fact, for the year 2017, he testified, the proposed change would have affected the allocation of fuel cost only during the 14% of hours where excess generation existed.

Mr. Swez responded to Mr. Dauphinais' testimony concerning the stacking methodology proposal, as well. Specifically, he addressed Mr. Dauphinais' recommendation that the stacking proposal be approved only if the Company also agrees to credit retail customers with 100% of non-native sales margins. He agreed with Mr. Dauphinais, to the extent his recommendation pertained to traditional non-native sales to MISO, and not the new category of short-term bundled capacity and energy sales. He noted that in rebuttal testimony, the Company had revised its Rider 70 proposal to credit 100% of such traditional non-native sales margins to customers, and to continue the 50/50 sharing mechanism only for the new category of short-term bundled capacity and energy sales. He reiterated that changing to incremental cost stacking will more closely align the party that receives the benefit of running a unit with all the costs necessary to run the unit.

With regard to the OUCC's position on the purchased power benchmark, Mr. Swez testified in rebuttal that root cause analyses are extensive, very detailed, time consuming analyses completed only for significant generating unit outages and events. He stated it was unclear whether Mr. Eckert is proposing that the Company perform a root cause analysis on every outage of greater than 72 hours, or if he only wants the Company to submit root cause analyses that it completes. In any event, completing a root cause analysis for forced outages such as boiler leak repair or other repairs that are more routine in nature, unless the cause of the outage is very unusual, is unnecessary and would add an undue burden and undue cost. In sum, Duke Energy Indiana does not agree to the OUCC's request to complete a root cause analysis for any forced outage greater than 72 hours in length. Rather, he testified, Duke Energy Indiana will commit to continue to do what it does today; that is, Duke Energy Indiana will discuss in FAC proceedings major forced outages of units of 100 MW or more lasting more than 100 hours, and will also provide the any root cause analyses that were performed. In addition, Duke Energy Indiana will continue to supply the OUCC day-ahead and real-time unit offers and awards for the test days it selects. Mr. Swez stated that this has worked well and provides the OUCC and the Commission relevant information on outages that meet those established thresholds.

With respect to the OUCC's recommendation to continue to allow the OUCC 35 days to complete its FAC review and file FAC testimony, Mr. Swez testified that this schedule has worked well in the past and he has no concerns with this schedule going forward.

Mr. Swez next addressed the Sierra Club's recommendation that all of the Company's generating units should be "dispatched on an economic basis," not self-committed, or if it must self-commit units, then "Duke's own dispatch decision-making process should be readily transparent and justify the frequency of the unit's operation." He also addressed the Sierra Club's recommendation that the Commission open an investigation into the practice of self-commitment. He emphasized that Duke Energy Indiana already commits the Company's generating units on an economic basis, except as required for unit testing, operational requirements, or other infrequent reasons. He testified that the process that the Company performs daily to inform the commitment status decision for each unit is designed to minimize the total customer cost by maximizing each unit's economic value. In addition, he stated, for units that are committed by MISO, they are also being committed on an economic basis using MISO's security constrained economic dispatch. Finally, he testified that units are dispatched on an economic basis between their minimum and maximum capability when not required to run at a specific output as would be necessary for unit testing, operation requirement, or other reasons. Mr. Swez testified that by using both "Economic" and "Must Run" commitment status offers for different units on different days and times, the Company is working to minimize the total customer cost by maximizing the generators total margin. He stated that when it is advantageous to do so, utilizing a commitment status offer of

Must-Run in the MISO energy markets does not necessarily mean that a generating unit was not economically committed. He emphasized that the MISO Day-Ahead Market construct was never designed to forecast economic commitments beyond the next day. Accordingly, for units with longer or higher start-up costs, the MISO Day-Ahead Market will typically not result in a commitment of these generating units from an off-line state when being offered with a commitment status of Economic, even though they may be the most economic choice over a multi-day period. As a result, he testified, always using an Economic commitment status could at times cause either the lowest cost unit to remain off-line or uneconomic cycling of certain units across multiple days.

Mr. Swez also pointed out that Sierra Club witness Comings' economic dispatch analysis offered to support his testimony failed to take into account the realities of self-scheduling units and contained a number of significant and incorrect assumptions or errors.

Further, Mr. Swez noted that the Company's generating unit offers, including the commitment status offer as well as resulting dispatch of the units, are already the subject of review during the Company's quarterly fuel clause filing. In other words, there already is a process in place for this examination each quarter. In addition, he stated, the Commission has already specifically considered this issue in Cause No. 42685, finding that "for those units that must be committed for several days or even weeks at a time, self-scheduling at minimum load will guarantee reliable and predictable operation of the units. The remainder of energy available from those units between minimum and maximum operating range can be offered in the day-ahead and real-time markets for economic dispatch." Cause No. 42685 at page 9 (IURC; June 1, 2005). In sum, he testified, there is no need for the Commission to embark on another investigation of a practice that is reasonable, common and well understood.

v. Evidence Developed at Hearing. At hearing, a different picture of Duke's unit commitment practices than how they were portrayed in the Company's rebuttal testimony was revealed. Under cross examination, Mr. Swez acknowledged that whenever the following units are available, Duke always offers into MISO Edwardsport on coal, one of its Cayuga units, and at least one and typically two or three Gibson units with a must--run commitment. As a result, MISO is required to operate these units at at least their minimum operating level regardless of the economics of such operation. Joint Intervenors submitted into evidence three of the daily economic reviews——referred to as "Profit & Loss Statements"——that the Company contends it uses in deciding whether to commit its generating units into MISO as must-run or economic. JI CX 32-C, 33-C, and 34-C. Those Profit & Loss Statements compare the cost of operating a unit over the next one to three weeks to the projected energy revenue that Duke would receive for such operation. The three Profit & Loss Statements in evidence reveal numerous instances of the Company committing Edwardsport on coal, a Cayuga unit, and/or one or more Gibson units as must--run despite Duke's own projection that doing so would lead to substantial financial losses. A more comprehensive review was not possible because Duke refused to produce in discovery more than a handful of its daily Profit & Loss Statements despite the clear relevance of those statements to the question of whether the Company is uneconomically self-scheduling its units and the existence of a non-disclosure agreement in this proceeding that would ensure that any confidential information in those statements would not be publicly disclosed.

~~v.~~vi. **Commission Discussion and Findings.** First, we note that no party took issue with the Company's proposal to recover PJM charges and credits related to its Madison Generating Station in either its FAC Rider, its RTO Rider, or Rider 70, as appropriate. Nor did any party take issue with the Company's proposal to eliminate the two-pass stacking process and perform the stacking process exclusively in the real-time market. Petitioner supported both of these proposals and we approve both.

Next, we address Petitioner's proposal to change its stacking process from an average production cost basis to an incremental production cost basis for long-term commitment generating units such as coal-fired and combined cycle natural gas units. Mr. Swez explained why this proposal is reasonable, in terms of allocating no-load costs to the drivers of those costs, which in most cases will be native load generation needs. The OUCC objected to this proposal on the basis of fairness, because the change appears to be more likely to allocate more no-load costs to retail customers. The Industrial Group objected if the Company continued to retain a share of non-native sales margins, but did not have an objection if the Company credited non-native sales margins 100% to retail customers. Although we appreciate the OUCC's concern with potentially allocating more fuel costs to retail customers, we find that the Company's proposal is consistent with the allocation of costs to the groups of customers that cause such costs. We also note that in its rebuttal testimony, the Company agreed to credit retail customers with 100% of its traditional non-native sales margins. Accordingly, we approve the Company's proposal to change its stacking process to an incremental production cost basis for its long-term commitment generating units.

We also approve the Company's proposal to eliminate the purchased power benchmark process. No party objected to this proposal, and the Company demonstrated that circumstances have changed since we instituted the benchmark years ago. Additionally, as Mr. Swez noted, eliminating the benchmark process in no way precludes our ability to scrutinize power purchases in the FAC process, as necessary.

We also approve the continuation of the process whereby the OUCC is given 35 days to review the Company's FAC application and file FAC testimony. No party objected to this, and it has worked in practice.

Additionally, we are concerned that Duke appears to be uneconomically and imprudently committing as must-run some of its generating units, and believe that further investigation of this issue is warranted. ~~address the Sierra Club's recommendations that all of the Company's generating units should be "dispatched on an economic basis," not self-committed, and that the Commission open an investigation into the practice of self-commitment.~~ While Mr. Swez provided a lengthy explication of the Company's dispatch process, and how it dispatches its units so as to minimize total customer costs by maximizing the generators' total margins, it appears that such process is not followed at Edwardsport, one Cayuga unit, and at least one and typically two or three Gibson units, each of which the record establishes Duke commits as must-run units whenever they are available. The limited number of Profit & Loss Statements that Duke produced suggest that the Company is committing as must-run such units even in the face of its own projections of significant losses, which lends credence to Sierra Club witness Comings' testimony that Duke is uneconomically self-committing as must-run Edwardsport and other generating units.

Contrary to Duke's contention, our Order in Cause No. 42685 (JI CX 28) does not shield the Company's unit commitment practices from review. For one thing, that Order was issued in 2005 and, as Mr. Swez acknowledges, the energy markets have changed significantly since then. In addition, the language from the Order quoted by Mr. Swez was not a "finding" of the Commission but, rather, a summary of Duke's testimony in that proceeding. As for our actual findings in Cause No. 42685, we merely deemed "reasonable" the considerations Duke identified as the basis of its (hypothetical) future commitment decisions. We did not conclude that self-commitment would be reasonable in all circumstances, and did not exempt Duke's commitment decisions from future review.

With regards to Duke's contention that unit commitment issues should be addressed in FAC proceedings, the Commission has opened a subdocket in Cause No. 38707 FAC 123 S1. In that subdocket, we will investigate the causes, impacts, and prudency of the Company's self-scheduling practices (including any fuel procurement and management practices that contribute to such self-scheduling) and determine whether there are excessive fuel and operating costs resulting from such practices the recovery of which should be disallowed. Additional steps, however, are needed to ensure full transparency around and evaluation of Duke's unit commitment practices. As such, we hereby create a Unit Commitment reporting requirement, similar to the purchased power benchmark established in Cause No. 41363. In each FAC filing, Duke is hereby required to identify for each of its Edwardsport, Cayuga, and Gibson units each time period that its own economic review projected that the costs of operating a unit over a 7-day period would exceed the energy revenues expected to be received from such operation, and the commitment decision that Duke made for each unit during such time period. The Company shall also report actual costs incurred and revenue earned for those units when actual operating costs have exceeded energy revenues for any units over a 7-day period, if committed as must-run. For each time period in which Duke decided to must-run a unit, and projected or actual operating costs exceeded the energy revenues for that unit, the Company must explain that commitment decision and identify both the projected and actual loss incurred over the time period. Such reporting requirements will provide the Commission and intervenors with the ability to review and ensure the prudency of Duke's unit commitment decisions during each FAC period. If we find during a FAC proceeding that Duke has engaged in imprudent self-commitment, we will disallow recovery for the elevated fuel and other operating costs.

In addition to review of specific unit commitment decisions in the expedited quarterly FAC proceedings, a more comprehensive annual investigation of Duke's commitment practices is warranted. We are aware that the Minnesota Public Utilities Commission recently opened a docket to investigate self-scheduling practices by utilities in that state. *In the Matter of the Review of the 2017–2018 Annual Automatic Adjustment Report for All Electric Utilities*, Docket No. E-999/AA-18-373, Order Accepting 2017–2018 Electric Reports and Setting Additional Requirements (Nov. 13, 2019) (establishing Docket No. E-999/CI-19-704, *In the Matter of an Investigation into Self-Commitment and Self-Scheduling of Large Baseload Generation Facilities*). In doing so, the Minnesota Commission identified a list of data and information needed to allow for such investigation and ordered the utilities to produce that data. *Id*. at 8-9. We hereby order that by March 1 of each year, Duke will produce the data and information identified in the Minnesota Commission order for the previous calendar year.

Finally, we note that Duke contends that it needs to must run one of its Cayuga units at a level of at least 300 MWs in order to generate the steam that it is contractually required to provide to one customer, International Paper. It appears that such self commitment of one Cayuga unit may often be uneconomic, especially given that, in 2019, the other Cayuga unit "has been offered with a commit status of Economic for entire months at a time, since it was better for the Company's customers to have the unit off-line and purchase energy to serve our customers [*sic*] demand from MISO,~~.~~" in the words of Duke witness Swez. -There is no evidence in this record as to whether any payments by International Paper under the steam contract accrue to the benefit of customers and, if so, whether such payments outweigh the costs of any uneconomic operation of a Cayuga unit that the steam contract necessitates. *See* JI CX 29. Further investigation of this issue should occur in the 38707 FAC 123 S1 subdocket and annual commitment practices reviews, guided by the fact that Duke and/or International Paper, rather than ratepayers, should be responsible for any losses resulting from the steam contract.

~~He demonstrated that the MISO 24-hour day ahead market is an imperfect fit with longer term generation commitment decisions particularly for units that have longer start up times. We agree with the Company that committing units on solely a short term "Economic" basis would not be consistent with the objective of minimizing total customer costs. Accordingly, we reject the Sierra Club's recommendation that all units should be so dispatched. Additionally, we will not adopt the Sierra Club's recommendation that we open an investigation into the practice of self-commitment. We have not found any basis in this record to order such an investigation. We also note that the Company's dispatch decisions are reviewed regularly in FAC proceedings. Finally, for the foregoing reasons, we reject the Sierra Club's proposal to reduce the Company's O&M expense levels to reflect what it characterizes as economic dispatch losses. The Company's past dispatch decisions and methodologies have been reviewed by this Commission in prior FAC proceedings and found to be reasonable. It would be impermissible retroactive ratemaking for the Commission to approve any disallowance in this proceeding.~~

d. OUCC Benchmarking Analysis.

i. OUCC's Evidence. OUCC witness Dismukes, sponsored the OUCC's Benchmarking Analysis. Dr. Dismukes examined the Company's plant investment trends over the past several years. His Schedule DED-7 presents a list of peer utilities used in his benchmarking analysis and their respective descriptive statistics.

Dr. Dismukes included an analysis of the Company's production plant investment trends as compared to that of its peers in his Schedule DED-8. He stated the Company's net transmission plant investment compared to its peers was set forth in Schedule DED-9. He added that the Company's net distribution plant investment compared to that of its peers was set forth in Schedule DED-10, and its net general plant investment comparison was set forth in Schedule DED-11.

The benchmarking comparisons Dr. Dismukes prepared for the Company's O&M expenses were set forth in Schedules DED-12, DED-13 and DED-14, and benchmarking of the Company's Administration and General ("A&G") expenses were set forth in Schedule DED-15. As a result of the foregoing benchmarking comparisons between the Company and its peer group, Dr. Dismukes concluded (i) the Company's projected annual growth rate of 10.3% in production O&M expenses per MWh far outpaces the peer group five year growth rate of 0.3 percent; (ii) the projected annual growth rate of 15.2 percent in the Company's net distribution plant per MWh far outpaces the Company's five year average of 9.9%; and (iii) the Company's net general plant per MWh is projected to grow by 24 percent per year through 2020, which is greater than its five year average growth rate of 15.2 percent.

Dr. Dismukes concluded his benchmarking testimony by recommending the Commission require the Company to undertake an in-depth review of its production and distribution O&M expenses. He further suggested the Commission should initiate a collaborative proceeding in which the Company, the Commission and other interested stakeholders can create, analyze and discuss appropriate benchmarking metrics for the Company.

ii. Petitioner's Rebuttal Evidence. Company witness Christopher M. Jacobi disagreed with Dr. Dismukes' benchmarking analysis and stated the OUCC's reflected peer group of companies may not be comparable. Mr. Jacobi said, with respect to the generation mix, that Dr. Dismukes included companies that have nuclear generation (*e.g.*, Kansas Gas and Electric Company) and some with significant amounts of hydro generation. Mr. Jacobi testified generation mix differences can have a significant impact on net plant in-service balances, as well as annual non-fuel O&M costs.

With respect to environmental compliance equipment, Mr. Jacobi stated there are companies included in the benchmarking peer group that have incurred significant costs to comply with federally mandated environmental regulations, and there are companies that had more limited compliance requirements due to their generation mix or because they have chosen to shut down facilities.

As to sales for resale, Mr. Jacobi testified there are companies included that have approximately 30% of their MWh sales attributable to wholesale customers (*e.g.*, Mid-American Energy) and then there are some that have zero wholesale sales (*e.g.*, Northern States Power Company). Mr. Jacobi continued with a discussion of the issues he had with respect to Dr. Dismukes' benchmarking of service area characteristics, own versus purchase transmission, regulatory/accounting treatment, and 2020 forecast. Mr. Jacobi disagreed with Dr. Dismukes' benchmarking analysis because of the differences between the various company demographics, generation mix, types of sales, future forecasts, etc.

Finally, Mr. Jacobi disagreed with Dr. Dismukes suggestion that the Commission should take an in-depth review of the Company's production and distribution O&M and initiate a collaborative proceeding to discuss benchmarking metrics. He stated that while there can be valid uses for benchmarking against those in the industry, trying to set rates based on average costs or benchmark studies is not appropriate and concluded no separate collaborative regarding benchmarking is needed.

iii. Commission Discussion and Findings. Our review of the evidence provided by the parties on this issue persuades us that the OUCC's benchmarking comparisons in Dr. Dismukes' schedules are flawed and not representative for use in making comparisons to Duke Energy Indiana. There are sufficient differences between the various company demographics, generation mix, types of sales future forecasts and other factors that do not support the conclusions suggested by OUCC witness Dr. Dismukes. As a result, we do not believe that it is necessary or appropriate for this Commission to take an in-depth review of Duke Energy Indiana's production and distribution O&M and initiate a collaborative proceeding to discuss benchmarking metrics. Therefore, we reject the OUCC's suggestions.

e. Waivers of 170 IAC 4-1.

i. Petitioner's Evidence. Company Witness Hunsicker testified that the Company was seeking the following waivers of 170 IAC 4-1 for the implementation of Customer Connect:

- 170 IAC 4-1-16(c)(2) as it relates to the signature requirements for payment agreements.

- 170 IAC 4-1-13(a)(1) as it relates to providing the beginning and ending meter readings, specifically for certain interval-billed rates, to allow the Company to provide usage information only on the customer's bill. Ms. Hunsicker testified that the inclusion of meter readings was more meaningful under traditional rate structures; however, with interval usage the beginning and ending meter readings are no longer relevant to the customer.

- 170 IAC 4-1-16(e) is needed to allow the Company to enable all customers' preferred method of communication as it relates to their energy bill. Ms. Hunsicker testified that the Company plans to provide all customer bills in the manner the customer has designated.

ii. Commission Discussion and Findings. The undisputed evidence presented in this case demonstrates that for the Company to successfully implement Customer Connect the waiver requests, as outlined by Ms. Hunsicker are necessary. Specifically, 170 IAC 4-1-16(c)(2), 170 IAC 4-1-13(a)(1), and 170 IAC 4-1-16(e). The undisputed evidence demonstrates that for the Company to effectively implement Customer Connect and enhance the customer experience a waiver of these rules is required. Moreover, the Company has demonstrated that the customer protections at the heart of these IAC provisions will not be lost as a result of the waivers and implementation of Customer Connect.

f. Affordability/Low-Income Collaborative.

i. Petitioner's Evidence. Company witness Pinegar described the Company's current programs designed to help low income customers. These programs include allowing customers to make payment arrangements to spread out past due amounts, defer due dates, sign up for budget bulling payment plans, third party notification of bills and disconnection notices, and several specific low income assistance programs. Mr. Pinegar stated Duke Energy Indiana offers three low income energy efficiency programs to help customers save on energy costs, including the Neighborhood Energy Saver Program, Agency Assistance Portal's program, and Low-Income Weatherization Program.

Mr. Pinegar also introduced Duke Energy Indiana's Helping Hand program, through which the Company provides emergency energy assistance through the federal government's Low

Income Home Energy Assistance Program ("LIHEAP"). Company witness Quick provided additional detail on the Helping Hand program, stating the Company's shareholders historically contribute about $200,000 per year, which in recent years has been augmented by settlement commitments to $700,000 annually from 2013 to 2017 and $600,000 in 2018. On cross-examination, Mr. Pinegar testified the amount of Helping Hand funding has been increased to $750,000. Ms. Quick detailed that the Helping Hand program provides financial assistance to eligible customers through a one-time $300 payment on a customer's account. She stated the Company has partnered with the Indiana Community Action Energy Assistance Program to distribute program funds to customers eligible for LIHEAP.

Mr. Pinegar acknowledged the proposed rate increase will impact low income customers the hardest, and Duke Energy Indiana welcomes a collaborative discussion about ways to continue and ramp up energy assistance to low income customers. Mr. Pinegar explained the Company proposes to convene a Low Income Collaborative with interested stakeholders at the conclusion of this rate proceeding with a goal of introducing additional energy assistance for its customers.

ii. Intervenor Evidence. Joint Intervenors' witness John Howat provided testimony on low-income affordability issues. Mr. Howat first recommended the Commission direct Duke Energy Indiana to implement a comprehensive low-income bill payment assistance program. Mr. Howat asserted there is an electricity service affordability problem among Duke Energy Indiana's lower income residential customers, and as a result, recommended Duke Energy Indiana develop and make available a low-income rate that reduces low income customers' payments to a more affordable level. He suggested this be done pursuant to a tiered discount rate program. He also recommended the Company implement an arrearage management program that provides LIHEAP-eligible customers who carry an overdue balance with a reasonable opportunity to have those balances written down over time through timely payments on more affordable current bills.

Mr. Howat also recommended that the Company report monthly to the Commission and stakeholders a series of data points. Mr. Howat suggested that following data be filed: general residential and low-income customer accounts, billing, receipts, arrearages, notices of disconnections, bill payment agreements, disconnections of service for nonpayment, reconnections of service after disconnection for nonpayment, accounts written off as uncollectible, and accounts sent to collection agencies.

iii. Petitioner's Rebuttal Evidence. Ms. Quick stated, with regard to Mr. Howat's proposals about development of a low income rate and an arrearage management program, that the Company is not averse to discussing such issues with a broad set of stakeholders. For this very reason, the Company has proposed to convene a Low Income Collaborative with interested stakeholders at the conclusion of this rate case. Ms. Quick said the Company believes a Low Income Collaborative, occurring separate and apart from all the other issues involved in a rate case, will be the forum most likely to achieve broad consensus on ways to further assist low income customers.

Ms. Quick also addressed Mr. Howat's data collection proposal. She stated the Company already provides a significant amount of these metrics to Joint Intervenors and others pursuant to the IGCC-15 settlement, and all of the data is made public. Ms. Quick stated that the Company does not agree with Mr. Howat's proposal. However, Ms. Quick added the Company is willing to provide its current public report to the Commission going forward. Any further reporting issues are better left for the Low Income Collaborative.

iv. Industrial Group's Cross-Answering Testimony. Industrial Group witness Phillips explained his opposition to using a per kWh charge to provide for the recovery of the cost of Mr. Howat's proposed programs.

v. Commission Discussion and Findings.

Duke recognizes that "the rate increase proposed herein will impact low income customers the hardest. To that end, [Duke is] willing and would welcome a collaborative discussion about ways to continue and ramp up energy assistance to low income customers." Petitioner's Ex. 1, p. 38; *see also* Tr. A-21, lines 2-4, and Tr. A-65, lines 17-21. Thus, Duke "proposes to convene a Low Income Collaborative with interested stakeholders at the conclusion of this rate case proceeding with the goal of introducing additional energy assistance for Duke customers." Petitioner's Ex. 1, p. 38. Duke provided no additional information or stated goals about said collaborative, and Duke made no commitments or otherwise offered a plan for its Low Income Collaborative. *See generally* Petitioner's Ex. 1 and Petitioner's Ex. 55. In fact, at the evidentiary hearing, Duke Energy Indiana's President said he cannot even commit "to moving forward with filing a program or filing a rate as an outcome of the low income collaborative." Tr. A-75, lines 4-13.

Joint Intervenors addressed this proposal and the overall need for low income assistance in Duke's service territory. Joint Intervenors presented undisputed evidence in this case that: arrearage rates for Duke's LIHEAP customers rose to over 30% on an annual basis between January 2017-March 2019 (JI Ex. 3, p. 8); post-moratorium shutoff notice rates to Duke's LIHEAP participants spiked to between 20-30%, while notice rates to Duke's general residential customers hovered in the 10% range (*id.* at 9); and, an estimated 851,000 people residing in Duke's service territory live at below 200% of the federal poverty level (*id.* at 11).

While Joint Intervenors noted appreciation for Duke's recognition of the low income and affordability problems in its service territory, Joint Intervenors argued Duke lacked meaningful commitments to address low income issues and overall affordability in Duke's service territory. Tr. A-73-A-75. Joint Intervenors also voiced frustration with regard to the fact that CAC and other stakeholders had already participated in a collaborative with Duke to discuss low income issues and even presented specific low income rate design proposals that Duke never pursued. *See* Settlement Term 5(G) in the Final Order in IURC Cause No. 43114 IGCC 14 (JI CX 1) ("The Settling Parties agree to work collaboratively for the two years following the date of a final order from the Commission approving the Settlement to consider programs or options to assist low income customers and for increasing solar-powered generating facilities in Duke Energy Indiana's service territory. The Settling Parties will meet at least quarterly to discuss these issues. An attendee shall take detailed minutes at any meeting. The minutes will be provided within two weeks of any meeting to all Settling Parties.")

Thus, Joint Intervenors recommended that the Commission direct Duke to make meaningful steps to address the low income and affordability problems in its service territory that

Duke itself acknowledges. Specifically, Joint Intervenors propose a low-income rate that reduces low-income customers' payments to a more affordable level, and an arrearage management program that provides LIHEAP-eligible customers who carry an overdue balance with a reasonable opportunity to have those balances written down over time through timely payments on more affordable current bills. Joint Intervenors' witness Howat found that lowering the electricity burdens and writing down pre-program arrears of 17,370 of the Company's customers participating in LIHEAP entails program benefit and administration costs of an estimated $16.2 million for the first year of program implementation, based on Duke's customers, sales and revenue data, as filed in its 2018 FERC Form 1, and an assumed average preprogram arrearage level of $200 per participant with a participation level of 17,370 customers distributed evenly through the 3 income tiers as part of the percentage of bill discount component of the program. This includes administration costs of 7% to implement both the percentage of bill discount component and the arrearage management write-down component. Based on the sum of program benefit and administrative expenses, the estimated total cost of the program by Joint Intervenors represents 0.681% of the Company's revenues from sales to residential, commercial, and industrial customers. *See* DEI 2018 FERC Form 1.

We agree that Duke's commitment to have yet another low income collaborative with no meaningful action falls short of Duke's explicit recognition that something must be done to lessen the impact of any rate increase to its low income customers. *See, e.g.*, Petitioner's Ex. 1 at 38. Rather than propose a specific solution or even a process to arrive at a solution, Duke proposes a collaborative discussion with interested stakeholders but offers no specific details, commitments, or other information.

Although I.C. § 8-1-2-68 prohibits relationships between rates that are unduly discriminatory, a rate is not unlawful merely because it differs from some other rate. It is only rate differentials that discriminate *unduly*, or for insufficient reasons, that are unlawful. *ICC v. Baltimore & Ohio R.R.*, 145 U.S. 263 (1892). "A rule prohibiting discrimination cannot be interpreted as requiring absolute uniformity of rates or prices, nor as prohibiting, under any and all circumstances, a discrimination by performing services for one person at a price or rate lower than that exacted of others." *Richmond Natural Gas Co. v. Clawson*, 155 Ind. 659, 58 N.E. 1049 (1900). *See also* 28 Ind. Law Encyc. Utility Regulatory Commission § 15. For example, many utilities offer rates based on reasons such as economic development or for employee retention. *See, e.g.*, Cause No. 44576/44602, IPL Tariff No. 7 Employee Billing; 2013 Ind. PUC LEXIS 43, *394, 303 P.U.R.4th 384, (approving I&M's employee discount as "a reasonable measure to attract and retain employees"); 2011 Ind. PUC LEXIS 369, *234, (approving modifications to NIPSCO's Economic Development Rider); 2011 Ind. PUC LEXIS 115, *295, 289 P.U.R.4th 9 (approving changes to Vectren's Economic Development Rider and Area Development Rider); 2009 Ind. PUC LEXIS 107, *30, 273 P.U.R.4th 310 (approving a settlement which included a "proposal to expand its Economic Development Program, which would include, among other things, the restoration of an economic development rider, establishment of an economic development grant fund, increased support to local economic development organizations, and research and marketing"). In the case of Duke's service territory, sufficient reasons exist to provide a rate specific to Duke's most vulnerable, low income population.

There are distinctions between low income residential customers and other customers to justify the difference in rate. The poor financial health of Duke's most vulnerable population is evident. Observing recent trends in seriously past due accounts and notices of disconnection for nonpayment among Duke's low-income residential customers receiving benefits through LIHEAP and Duke's general residential customers not participating in LIHEAP reveals severe payment difficulties among many low-income customers. The high rate of low-income arrearages is a reliable indicator of low-income affordability problems. The affordability problems outlined above constitute a threat to the home energy security of Duke's low-income customers and call for program and policy interventions to mitigate that threat. Although Duke argues that there are already options for residential customers struggling to pay bills, these options, like crisis funding, have massive gaps and severe limitations. Most importantly, none of these options provide for monthly bill affordability.

It is certainly within the Commission's jurisdiction and authority to determine whether or not Duke's low income customers are in need of assistance and to order a low income rate within the context of a base rate case. The legislature entrusted the Commission with the ability to regulate public utilities, including Duke, and to determine complex matters such as this. We have already allowed a low income payment assistance program for several natural gas utilities called the Universal Service Fund in Cause No. 43669. In that case, we noted our preference for determining this type of program in the context of a base rate case such as this proceeding ("we find that these programs offer complexities with respect to ratemaking that should ultimately be addressed in the context of a utility base rate case rather than as a single issue under the AUR Act.") *Id.* at 29-30. Since then, we have approved settlement agreements to begin low income rate programs in I&M, IPL, and NIPSCO's service territories. *See* Final Orders approving Settlements in IURC Cause Nos. 44967, 45029, and 45159.

It is evident to the Commission that the status of Duke's most vulnerable low income population warrants the specific rate and arrearage management program as proposed by Joint Intervenors. Joint Intervenors' witness Howat provided his expert opinion as to the general design that would be appropriate for Duke's low income residential population, which is particularly helpful since Mr. Howat helped with the design of the natural gas utilities' Universal Service Fund still in use in Indiana. He found that to help ensure energy security for low-income residents, what is needed is an electricity affordability program that serves LIHEAP-eligible residential electricity customers at or below 200% of the federal poverty level; lowers program participants' electricity burdens to an affordable level; promotes regular, timely payment of electric bills by program participants; comprehensively addresses payment problems associated with program participants' current and past-due bills; is funded through a mechanism that is predictable while providing sufficient resources to meet policy objectives over an extended timeframe; is paid for by all classes of electricity customers; and is administered efficiently and effectively, particularly when the design utilizes organizations that currently qualify LIHEAP participants, incorporates a "straight discount" on billing amounts, and incorporates a simple kWh surcharge to fund program benefits and operations, as well as an arrearage management program. This enhanced affordability makes it more likely that the household will be able to retain uninterrupted access to necessary service and reduces the likelihood that the customer will be faced with collection activities such as receipt of disconnection notices and requirement to enter into a deferred payment agreement.

The Commission agrees with the bill discount and arrearage management design proposed by Joint Intervenors. It is in the public interest to use this framework laid out by Joint Intervenors. The Commission approves a charge of $0.00064 per kWh to Duke's customers based on DEI's

2018 sales of 24,400,000 MWH, in addition to charges otherwise approved in this proceeding, to fund low-income payment program costs of $16.2 million, as recommended by Joint Intervenors. The Commission orders Duke to make a compliance filing within 30 calendar days of the date of this order with revised tariffs to implement a discounted rate of 25% for LIHEAP electricity customers and an explanation of how it will handle the arrearage management write-down and other aspects of the program. The Commission strongly encourages Duke to work with Joint Intervenors in preparing the program and compliance filings. Parties will have an opportunity to respond to the compliance filing 30 calendar days after it is filed.

Joint Intervenors also requested that the Commission order Duke to conduct regular, public reporting of certain affordability metrics. In the context of this proceeding, Duke agreed to continue the reporting it had agreed to pursuant to the settlement agreement approved in IURC Cause No. 43114 IGCC 15 and to begin publicly filing such with the Commission. We appreciate Duke's willingness to continue to report this information, but note that this is not as comprehensive as requested by Joint Intervenors. Thus, we direct Duke to work with Joint Intervenors and other interested parties to expand its reporting and increase the frequency by which Duke files said reports.

~~We appreciate the issues raised by Mr. Howat. We also appreciate the efforts Duke Energy Indiana has made in the past with regard to low income customers, and we further appreciate the commitment the Company has made with regard to addressing the issues raised by Mr. Howat, and other issues, in a Low Income Collaborative. We agree that a Low Income Collaborative, occurring separate and apart from the many other issues in this rate case, has a greater chance of broad consensus relative to this proceeding. As such, we decline to adopt Mr. Howat's proposals. However, we approve Duke Energy Indiana's proposal to convene a Low Income Collaborative with all interested stakeholders. Because the ongoing collaborative effort will not be occurring in the context of an open docket, the Commission's technical staff should actively participate in the process. For purposes of 170 IAC 1-1.5, Commission's technical staff shall be authorized to participate in the collaborative without being subject to 170 IAC 1-1.5-3 and -4~~.

g. **Performance Metrics Collaborative.**

i. **Petitioner's Evidence.** Company Witness Davey testified that it recognized from prior rate case orders for other utilities that the Commission has a keen interest in performance metrics. As such, at the conclusion of this rate case, the Company proposes a collaborative process with interested stakeholders to develop annual reporting for performance metrics. No other party addressed this issue.

ii. **Commission Discussion and Findings.** We appreciate the parties' willingness to consider the value that is added by the collaborative process. The Commission views the collaborative process as an opportunity for all parties to dialogue on how to improve utility operations. Such a process was created coming out of the recent rate cases for NIPSCO, IPL, and I&M. We believe performance metrics can be of significant value to the Commission and customers. Thus, we find that Duke Energy Indiana shall facilitate a meeting with interested stakeholders within 12 weeks of the effective date of the Order in this Cause to collaborate on a path for moving forward with a performance metrics initiative. We anticipate that it will enable comparisons of Duke Energy Indiana's performance over time and in comparison to similarly situated utilities. Because the ongoing collaborative effort will not be occurring in the context of an open docket, the Commission's technical staff should actively participate in the process. For purposes of 170 IAC 1-1.5, Commission's technical staff shall be authorized to participate in the collaborative without being subject to 170 IAC 1-1.5-3 and -4. In order that the Commission and interested stakeholders may stay abreast of the collaborative process, we direct Duke Energy Indiana to make a progress update filing with the Commission within 90 days of the initial meeting of the collaborative. We also direct Duke Energy Indiana to file quarterly reports for the first year and an annual report by October 1, 2021, and for each year thereafter until otherwise indicated by the Presiding Officers.

h. Contractor Policies.

i. Intervenor's Evidence. David Frye, Business Manager of the Indiana Laborers District Council ("ILDC") testified regarding changes that he believed would need to occur in Duke Energy Indiana's rate filing to align with his recommendations on mitigating the workforce impact from the transition away from coal. He also recommended that the Company implement local worker construction job transparency and reporting requirements for future gas and renewable generation projects. Mr. Frye added that Duke Energy Indiana should include new language in future renewable power purchase agreements to give a preference for projects that pay fair wage and benefits and prioritize the use of local residents. Finally, Mr. Frye testified the Company should implement a responsible contractor policy for contracted out services, such as vegetation management, traffic control and distribution construction projects.

ii. Petitioner's Rebuttal Evidence. Ms. Hart testified in rebuttal to Mr. Frye's recommendations that the Company should adopt a responsible contractor policy. She indicated Mr. Frye's concerns are unfounded and that Duke Energy Indiana already has procurement policies in place that prioritize contractors with cost effective service, increased productivity and minimized workforce turnover. Ms. Hart also responded to Mr. Frye's recommendations for the Commission to mandate certain wage and benefits for contractors. She stated that Duke Energy Indiana reasonably manages its contractors today and there is no evidence to the contrary. Accordingly, she contended that the Commission does not need to direct any changes to the Company's existing policies, which provide for reasonable and efficient use of contractors.

Ms. Mosley also testified in rebuttal to Mr. Frye's proposed Responsible Contractor Policy. Mr. Mosley indicated ILDC apparently believes a Responsible Contractor Policy can help identify and reward contractors who provide cost-effective service, while increasing productivity and decreasing turnover of the Company's contracted-out workforce. However, because Duke Energy Indiana already has in place procurement policies that prioritize contractors with cost effective service, increased productivity, and minimized turnover of its workforce, Mr. Mosley asserted the Commission should not mandate wage or benefit levels, require additional reporting, mandate use of local residents, or require implementation of a new Contractor Policy as proposed by ILDC.

iii. Commission Discussion and Findings. We have reviewed and considered the evidence from ILDC witness Mr. Frye and the rebuttal testimony from Duke Energy Indiana witnesses Hart and Mosley. That evidence supports our finding that the Company already has in place procurement policies that prioritize contractors with cost effective service, increased productivity and minimized turnover of its work force. Therefore, we conclude that it is not necessary or appropriate for us to mandate that Duke Energy Indiana use local residents, or require it to implement a new Responsible Contractor Policy as proposed by ILDC.

19. **Confidentiality**. Duke Energy Indiana filed five Motions for Protection of Confidential and Proprietary Information on July 2, 2019, July 22, 2019, November 6, 2019, January 21, 2020, and February 2, 2020. The Industrial Group filed a Motion for Confidential Treatment of Certain Testimony of Michael P. Gorman on October 30, 2019. The Motions were supported by affidavits showing documents to be submitted to the Commission were trade secret information within the scope of Indiana Code §§ 5-14-3-4 and 24-2-3-2. The presiding officers issued docket entries and made rulings from the bench finding such information to be preliminarily confidential, after which such information was submitted to the Commission under seal. We find all such information is confidential pursuant to Indiana Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law and shall be held confidential and protected from public access and disclosure by the Commission.

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

1. Duke Energy Indiana shall be, and hereby is, authorized to place into effect base rates and charges for retail electric utility service rendered by it in the territories served by it in the State of Indiana in accordance with this Order, including an annual increase to its rates and charges of $361,790,000 (excluding changes in items remaining in riders and the utility receipts tax) which represents an increase in operating revenues of 14.37%. Said rates will produce total jurisdictional electric operating revenues of $2,879,742,000 and, on the basis of annual jurisdictional electric operating expenses of $2,268,030,000, will result in annual jurisdictional electric utility operating income of $611,712,000. Duke Energy Indiana is hereby authorized to file with the Commission a new schedule of rates and charges which will properly reflect, establish and provide the operating revenues herein authorized. Said schedule of rates and charges should be in accordance with this Order, including implementation of this rate increase in two steps as approved herein.

2. Duke Energy Indiana shall file with the Energy Division of this Commission, appropriate tariffs using the rate design criteria specified in this Order, including the rates and charges authorized herein for Step 1 and Step 2. For Step 1, Duke Energy Indiana shall file new schedules of rates and charges with the Energy Division of the Commission. For Step 2, Duke Energy Indiana shall file new schedules of rates and charges with the Energy Division of the Commission; however, for Step 2 Petitioner shall provide the OUCC and intervening parties sixty (60) days following the date of verification of actual used and useful property to state any objections to Duke Energy Indiana's verified actual test-year end net plant. If there are objections, a hearing may be held to determine Petitioner's actual test-year-end net plant in service, and rates will be trued-up (with carrying charges) retroactive to January 1, 2021. The rates and charges for Steps 1 and 2 shall be implemented upon approval of the filed tariffs on a service-rendered basis.

3. Duke Energy Indiana shall be, and hereby is, authorized to recover in its retail electric rates the following deferred costs, in accordance with this Order: Gallagher Station Unit 1 and 3 deferred costs; SO_2 emission allowance costs; Wabash River Unit 6 deferred costs; and coal ash basin closure and remediation expenses. Further, Duke Energy Indiana is authorized to defer, for subsequent recovery in its retail electric rates, the following costs: Edwardsport IGCC outage costs; Customer Connect costs; pension settlement costs; incremental vegetation management costs; and 316(a) and 316(b) compliance-related costs, all as discussed and approved in this Order. In addition, Duke Energy Indiana shall establish and maintain a Major Storm Reserve as set forth in this Order.

4. Commencing with the first of the month following effective date of updated base rates, Duke Energy Indiana is hereby authorized to place into effect the depreciation rates approved in this Order.

5. Duke Energy Indiana shall be, and hereby is, authorized to implement the changes to various Rate Adjustment Riders as approved in this Order, specifically changes to Riders 60, 61, 62, 63, 65, 66, 67, 68, 70, 71, 72 and 73, all as determined in this Order.

6. Duke Energy Indiana shall be, and hereby is, authorized to implement a decoupling mechanism and a decoupling rider, as provided in this Order.

7. Duke Energy Indiana shall be, and hereby is, authorized to implement the rate design proposals and tariff changes as approved in this Order.

8. Duke Energy Indiana is issued a federal mandate certificate of public convenience and necessity related to its coal ash expenditures included in this proceeding.

9. Duke Energy Indiana is granted a waiver of 170 IAC 4-1-16(f) as to the disconnection process and the waivers discussed in Waivers section, 18.e of this order.

10. Duke Energy Indiana shall be, and hereby is, authorized to utilize a base cost of fuel of 26.955 mills per kWh and a net operating income of $611,712,000 in its FAC proceedings. For purposes of computing the authorized net operating income for Indiana Code 8-1-2-42(d)(3), the increased return shall be phased-in over the appropriate period of time that Petitioner's net operating income is affected by the earnings modification as a result of the Commission's approval of this Order. In addition, Duke Energy Indiana is authorized a permanent waiver of the purchased power benchmark requirements. The OUCC is granted a 35-day period to review Petitioner's FAC applications and to file OUCC testimony in such proceedings.

11. Duke Energy Indiana shall be, and hereby is, directed to participate in a collaborative process involving Commission Staff and other parties concerning performance metrics and the low-income issues, as provided in this Order.

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

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

APPROVED:

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

**Mary M. Becerra
Secretary of the Commission**