FILED
March 30, 2020
INDIANA UTILITY
REGULATORY COMMISSION

STATE OF INDIANA
INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	:	**CAUSE NO. 45253**

<u>WALMART INC.'S SUBMISSION OF EXCEPTIONS TO DUKE ENERGY INDIANA, LLC'S PROPOSED ORDER</u>

Walmart Inc. ("Walmart"), by counsel, respectfully submits the attached limited Exceptions, shown in redline format, to the Proposed Order filed on March 3, 2020, by Duke Energy Indiana, LLC ("Duke Energy Indiana" or "Company"). The attached Exceptions reflect Walmart's recommendations for the Indiana Utility Regulatory Commission's ("Commission") consideration in this matter.

Please note that Walmart has only included the pertinent sections of Duke Energy Indiana's Proposed Order to which Walmart specifically takes exception; the fact that Walmart has not addressed each and every section of the Company's Proposed Order does not indicate Walmart's acceptance of Duke Energy Indiana's position on the issues not expressly addressed by these Exceptions. That said, unless specifically modified by these Exceptions, Walmart does adopt each party's summary of its own testimony and evidence as presented in each party's respective post-hearing filings.

Respectfully submitted,

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Dated: March 30, 2020

CERTIFICATE OF SERVICE

The undersigned hereby certifies that a true and correct copy of the foregoing document has been served by electronic mail, hard copies available upon request, this 30th day of March, 2020, upon the following counsel:

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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."[4] 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."[5] 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."[6] 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 from 8.45 percent to 8.80 percent) and determined that "all of these DCF analyses in the current market produce unrealistically low results."[7]

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;

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[4] Docket Nos. EL14-12-003 and EL15-45-000, *Order Directing Briefs*, 165 FERC ¶ 61,118 (November 15, 2018) at para. 34.

[5] 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.

[6] 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]

[7] 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.

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 [8] – 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: (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		

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

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. . . ."[9] Responding to arguments that the ECAPM is inconsistent with the use of adjusted betas, he further quoted Dr. Morin:

> 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.[10]

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		

[9] Roger A. Morin, *New Regulatory Finance* 175, 190 (2006).
[10] *Id*. At 191.

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 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.[11] In addition, he noted that full or partial decoupling mechanisms have been implemented by electric utilities in a majority of state jurisdictions.[12] 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 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, [13] while a second study found decoupling to have no statistically significant effect on investor perceived risk, and the cost of equity.[14]

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

[11] *See*, Petitioner's Exhibit 11-I.

[12] *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.

[13] 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.

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

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 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"[15] 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.

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

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 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. **<u>OUCC's Evidence</u>.** 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. <u>FEA's Evidence</u>. 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. Specifically, Mr. Chriss testified that the difference between the Company's requested 10.4% ROE and the national average ROE of 9.73% for vertically integrated utilities would equate to approximately $35.5 million, or 9% of the Company's proposed revenue deficiency.

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.

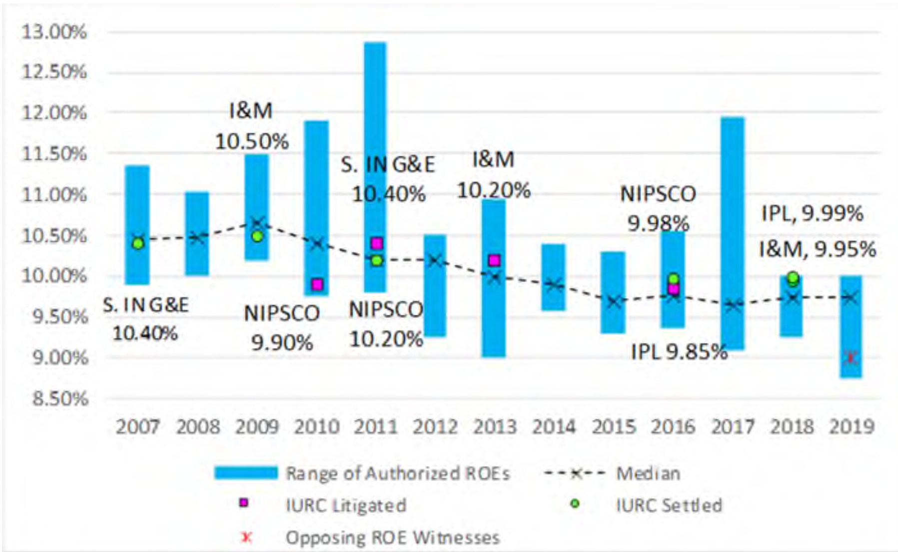
Mr. Hevert reiterated that the Opposing ROE Witnesses' recommendations fall from unreasonably low Discounted Cash Flow ("DCF") estimates, which are based on assumptions that do not align with market conditions. Because the Constant Growth DCF assumes valuation levels (including the Price to Earnings, 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)[16]



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 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.

[16] 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.

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.

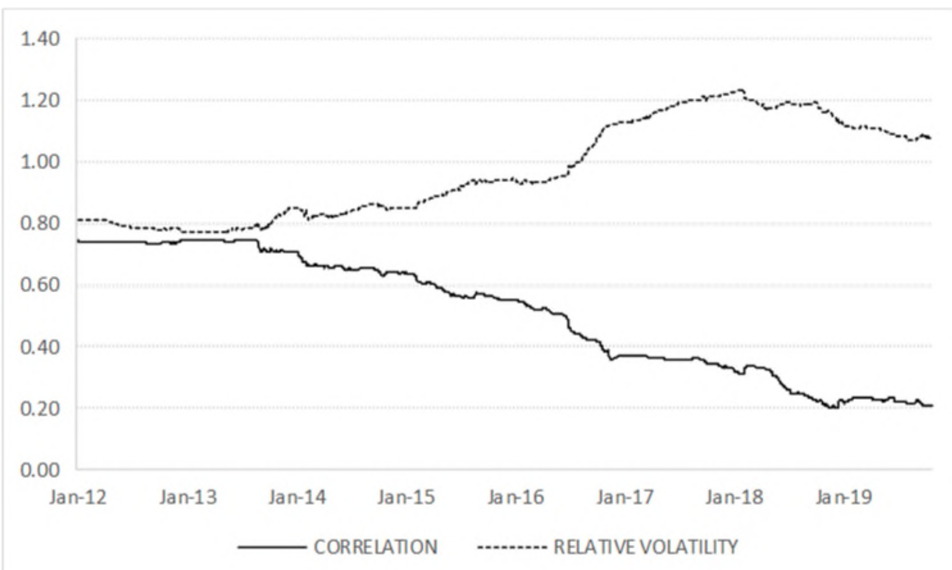
- In determining the expected growth rate that underlies the expected market return, the salient points are twofold: (1) investors rely on analysts' growth rate projections to frame their investment decisions; and (2) because it is meant to estimate the market return, it is the expected return on the 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[17]



- 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

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

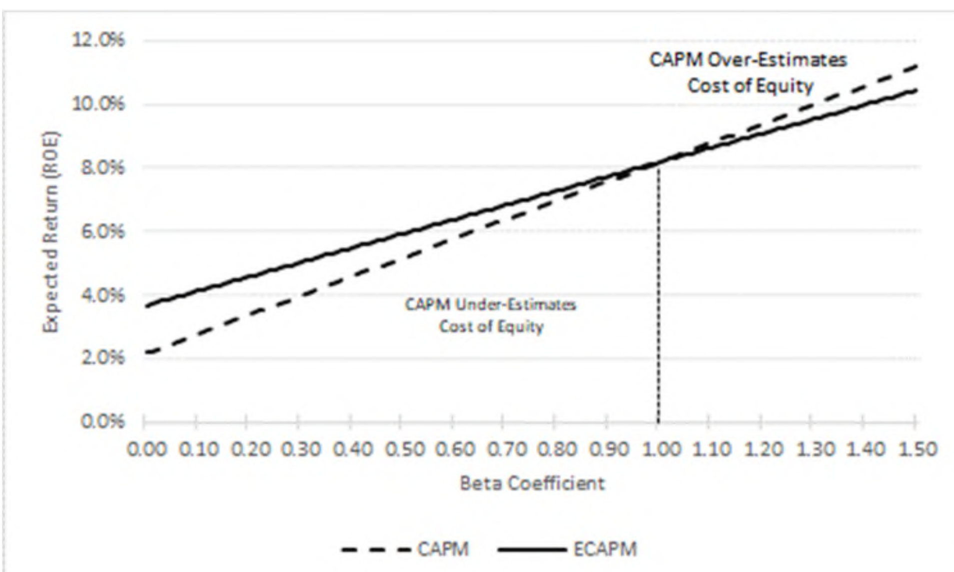
utilities could not benefit from the TCJA in ways other sectors could, they became relatively less attractive.

- 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."

- 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.[18]

- 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.[19] 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.

[18] Eugene F. Brigham, Louis C. Gapenski, Financial Management, Theory and Practice, 1994, The Dryden Press., at 341.
[19] 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.

- 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 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.[20] 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."[21]

- 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 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

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

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:

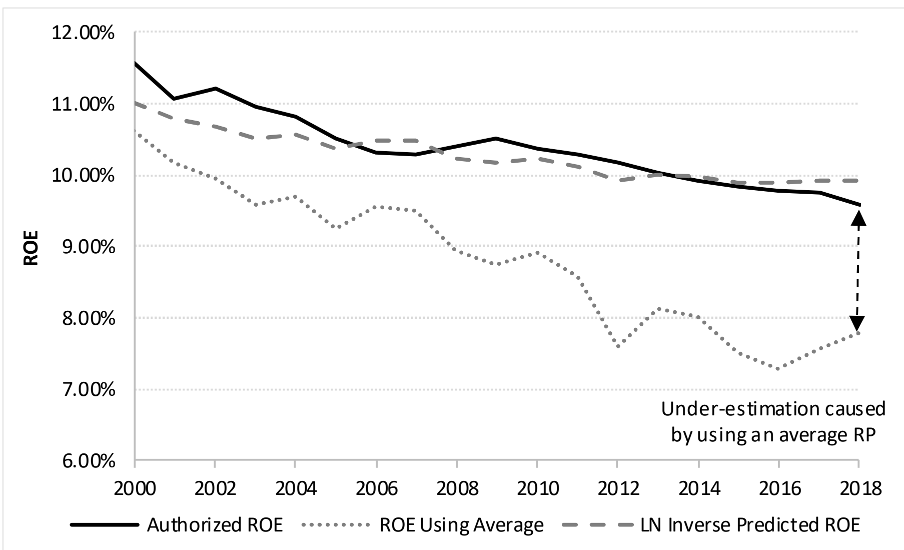
> … [p]ublished studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), and McShane (2005), and others demonstrate that, beginning in

> 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~~ argued ~~out~~ that Mr. Chriss's 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%

Commission Discussion and Findings. In setting the rate of return for Duke Energy Indiana, the Commission's decision must be framed by *Bluefield Waterworks & Improvements Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 43 S.Ct. 675 (1923) and *Federal Power Comm'n v. Hope Natural Gas, Co.*, 320 U.S. 591, 64 S.Ct. 281 (1944). The general standards these cases established require a cost of common equity set by the Commission be sufficient to establish a rate of return that will maintain the utility's financial integrity, attract capital under reasonable terms, and be commensurate with the returns that could be earned in investments in other enterprises of comparable risk.

The Commission is also mindful that "the cost of common equity cannot be precisely calculated and estimating it requires the use of judgment." *Indiana-American Water Co.*, Cause No. 44022, p. 35 (June 6, 2012). Due to this lack of precision, the use of multiple methods is desirable, in part, because no one method will produce reasonable results under all conditions and in all circumstances. The Commission is also mindful of the strengths and weaknesses of the various models typically used to estimate a utility's cost of common equity, and we find that with appropriate and reasonable inputs, models such as the DCF and CAPM can produce reasonable estimates of a utility's cost of common equity. Consistent with the standards in Hope and Bluefield, as well as under Indiana law, Duke Energy Indiana's authorized return on equity should be reasonable given the totality of the circumstances.

To meet the requirements set forth in Bluefield and Hope, the parties proposed various returns using the DCF model and other methods as bases for their positions. Mr. Hevert's analysis produced a range of 10.0% to 11.00%. He recommended the Commission adopt a COE of 10.40%. Mr. Garrett's estimated COE is about 6.3%, but he recommended a COE of 9.00% based on a range of 8.75% to 9.25%. Mr. Gorman's analysis produced a range of 8.50% to 9.30%. He recommended a COE of 9.00%. The testimony of these experts yields a recommended range of 8.5% to 10.4%.

In addition to the recommendations of these experts, while not determinative of the COE the Commission approves in this Cause, we note the COE awarded to Indiana's vertically integrated electric utilities outside of settled cases has been trending lower over time. *See*, *e.g.*, PSI Energy, Inc. (now Duke Energy Indiana) 10.5% in Cause No. 42359 (2005); Southern Indiana Gas and Electric Company 10.4% in Cause No. 43839 (2011); Indiana Michigan Power Company 10.2% in Cause No. 44075 (2013); Indianapolis Power & Light Company 9.85% in Cause No. 44576 (2016); and Northern Indiana Public Service Company LLC 9.75% in Cause No. 45159, with the most recent COE award for such an electric utility being 9.70% approved on March 11, 2020, for Indiana Michigan Power Company in Cause No. 45235. We find the evidence shows Mr. Hevert's recommended COE of 10.40% exceeds a reasonable estimate of Duke Energy Indiana's COE given current market conditions and recent COE decisions approved by the Commission and approved nationwide for investor-owned electric utilities. More specifically, the record reflects Mr. Hevert's constant growth DCF analysis relies on unsustainably high growth rates the Commission finds are unrealistic. In addition, we are not persuaded he appropriately considered the mitigation of risk associated with various regulatory mechanisms, including Duke Energy Indiana's use of a future test year in this proceeding and the riders and/or trackers approved for Duke Energy Indiana. His recommendations are also inconsistent with recent COE decisions approved nationwide for investor-owned electric utilities, based on intervenor Walmart's evidence, and with the lower trend, generally, by the Commission. While the Commission does not base its COE conclusion on national averages, the evidence presented demonstrates the trend in approved COEs for vertically integrated utilities, both in Indiana and nationwide, is lower than Duke Energy Indiana requests. We recognize financial strength is important for a utility to attract capital at a reasonable cost in order to make the investment necessary to fulfill its service obligations, but the evidence demonstrates investor-owned utilities similar to Duke Energy

Indiana and located in similar regulatory jurisdictions have been awarded reasonable and fair COEs that are below Duke Energy Indiana's requested range. Walmart Cross Ex. 2. We also take special note that the current economic conditions of Indiana and the entire nation, presented by the novel coronavirus pandemic, are very fluid and are presenting definite challenges to all sectors, including public utilities and their customers and prospective investors. Certainly, there is no justification to award a COE that is above the 9.74% average COE for vertically integrated utilities nationwide since 2016, and the Commission also notes that this was the average COE prior to our recent approval of the 9.70% COE for Indiana Michigan Power Company in Cause No. 45235.

The Commission has considered the analytical results based on a proxy group of electric utilities, as well as the risk factors associated with: Duke Energy Indiana's generation portfolio and environmental regulations; customer concentration; Duke Energy Indiana's planned capital expenditures, and the costs of issuing common stock. We find these risk factors are, however, lessened by the future test year Duke Energy Indiana used, the proposed increased customer charges, and the trackers Duke Energy Indiana is requesting and/or has in place, which serve to reduce risks of uncertainty Duke Energy Indiana would otherwise face. Having recognized the risk factors, we find it is important the Commission also recognize factors mitigating these risks. As the Commission stated in *Indianapolis Power & Light Co.*, Cause No. 44576, p. 42 (IURC March 16, 2016):

> Trackers that adjust rates for incremental investments or for costs that are nearly certain to be increasing serve to adjust the base line earnings for post rate case changes and address issues primarily associated with regulatory lag. Trackers that adjust rates for cost changes that are more unknown and that are equally likely to decrease or increase address the risk of volatile earnings results. The general effect of these trackers reduces the uncertainty of earnings that an investor can expect.

Having taken into consideration the foregoing factors and observable market data reflected in the record, including 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, expected inflation rates, and a general assessment of the current investment risk characteristics of the electric utility industry, combined with a thorough understanding of the Indiana jurisdiction and its risk mitigation ratemaking mechanisms, and Duke Energy Indiana in particular, the Commission finds a reasonable range for Petitioner's COE is 9.45% to 9.95%. Taking into consideration all the evidence presented, the Commission finds and concludes a 9.60% COE is fair and reasonable under the totality of the circumstances. This moderate decrement below the mid-point of the reasonable range recognizes the significant risk reduction afforded Duke Energy Indiana through the future test year and various trackers provided in its tariff as well as the very uncertain economic times that Indiana and the entire nation are undergoing, which would likely inform an even lower COE, though evidence to that end is not currently available and obviously was not presented in the course of this proceeding.

~~**vii.** 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:~~

~~**viii.** 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.~~

~~**ix.** 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.~~

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

~~**xi.** 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.~~

~~**xii.** 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.~~

~~**xiii.** 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:~~

~~**xiv.** (1) Return comparable to return on investments in other enterprises having corresponding risks;~~

~~**xv.** (2) Return sufficient to ensure confidence in the financial integrity of the petitioner;~~

~~**xvi.** (3) Return sufficient to maintain and support the Petitioner's credit [rating];~~

~~**xvii.** (4) Return sufficient to attract capital as reasonably required by the Petitioner in its utility business.~~

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

~~**xix.** Citing the Indiana Supreme Court, the Commission noted that:~~

~~**xx.** 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.~~

~~**xxi.** *Id*. at p. 47-48.~~

~~**xxii.** The Commission concluded that:~~

~~**xxiii.** ...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.~~

~~**xxiv.** *Id*. at p. 48.~~

~~**xxv.** 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.~~

~~**xxvi.** 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.~~

~~**xxvii.** 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.~~

~~**xxviii.** 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.~~

~~**xxix.** 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.~~

~~**xxx.** 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.~~

~~**xxxi.** 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.~~

~~**xxxii.** 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.~~

~~**xxxiii.** 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.~~

~~**xxxiv.** 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.~~

~~**xxxv.** 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.~~

~~**xxxvi.** 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.~~

~~**xxxvii.** 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.~~

~~**xxxviii.** 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.~~

~~**xxxix.** 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.~~

~~**xl.** 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.~~

~~**xli.** 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.~~

~~**xlii.** 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.~~

~~**xliii.** 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.~~

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

~~xlv.~~	~~xlv~~ ~~apitalization~~	~~x~~		~~xli~~
~~l. Des cription~~	~~li. in thousands)~~	~~l~~ ~~atio~~	~~ost~~	~~liv. eighted Cost~~
~~lv. Com mon Equity~~	~~lvi. 4,770,344~~	~~l~~ ~~40.98%~~	~~0.40%~~	~~lix. .26%~~
~~lx. Lon g Term Debt (estimated)~~	~~lxi. ,228,373~~	~~l~~ ~~36.33%~~	~~.50%~~	~~lxi~~ ~~.63%~~
~~lxv. Defe rred Income Taxes~~	~~lxv~~ ~~,447,756~~	~~l~~ ~~21.03%~~	~~.00%~~	~~lxi~~ ~~.00%~~
~~lxx. Una mortized ITC – Crane Solar~~	~~lxx~~ ~~0,999~~	~~l~~ ~~0.09%~~	~~.62%~~	~~lxx~~ ~~.01%~~
~~lxxv. Una mortized ITC – 1971 & Later~~	~~lxx~~ ~~,955~~	~~l~~ ~~0.02%~~	~~.62%~~	~~lxx~~ ~~.00%~~
~~lxxx. Una mortized ITC – Advanced Coal (IGCC)~~	~~lxx~~ ~~33,500~~	~~l~~ ~~1.15%~~	~~.62%~~	~~lxx~~ ~~.09%~~
~~lxxxv. Cust omer Deposits~~	~~lxx~~ ~~7,056~~	~~l~~ ~~0.40%~~	~~.00%~~	~~lxx~~ ~~.01%~~
~~xc. Tota l~~	~~xci~~ ~~11,639,983~~	~~x~~ ~~00.00%~~		~~xci~~ ~~.00%~~

11. <u>Forecasted Operating Income at Present Rates and *Pro Forma* Adjustments</u>.

a. <u>General.</u> 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

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. <u>Industrial Group's Evidence</u>. 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. <u>Petitioner's Rebuttal Evidence</u>. 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. <u>OUCC's Evidence</u>. 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. <u>Industrial Group's Evidence</u>. 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. <u>Joint Intervenors' Evidence</u>. 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. Walmart's Evidence. Walmart witness Chriss indicated that at the Company's proposed revenue requirement, Walmart does not oppose the Company's proposed revenue allocation, but regarding the Company's proposed subsidy/excess proposal stipulated that if the Commission determines that the appropriate revenue requirement is less than that proposed by the Company, the Commission should start with the Company's proposed revenue allocation and apply any reduction in revenue requirement in a manner that further moves customer classes towards their respective costs of service.

~~v.~~vi. **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.~~vii. **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.~~viii. **Commission Discussion and Findings**. 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.

We also agree with Walmart and Kroger, however, that additional steps should be taken now to reduce the existing subsidy/excess position of the various rate classes. This is particularly important given the long period of time that has existed between rate cases for the Company and Company witness Pinegar's testimony at the evidentiary hearing that there are no current plans by the Company to file more frequent rate cases. *See* Hearing Tr., p. A-57, lines 2-18. We are concerned that, absent more frequent rate cases which may or may not be in the best interest of the public, the existing subsidy/excess position of the various rate classes will be exacerbated going forward despite the proposal to reduce those subsidies/excesses by 5.1% right now. Considering that we are approving an overall revenue requirement increase that is less than what the Company has requested, but also considering the need to mitigate the impact on subsidized rate classes and to also provide those classes with the benefit of the reduced revenue requirement increase, we accordingly direct the Company to allocate the overall increase to rate classes in a manner consistent with the Company's overall approach but that also specifically applies 50% the benefit of the reduced revenue requirement on a *pro rata* basis to those classes that are currently contributing in excess of their cost to serve in order to further mitigate subsidies/excesses as they currently exist on the Company's system. We believe that this approach advances the important goal of moving rate classes toward their cost to serve while also upholding the principle of gradualism that the Company seeks to observe in this case. We also note that in the recent Indiana Michigan Power rate case (Cause No. 45235), we took a similar step by requiring an additional increase in the subsidy reduction for a single rate class, Indiana Michigan's streetlighting class. *See Indiana Michigan Power Company*, Cause No. 45235 (Order issued Mar. 11, 2020), p. 89. Based on the factors discussed, and in the manner discussed above, we believe that this approach is warranted for all of Duke Energy Indiana's subsidizing rate classes.

(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.

(D) **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 testified that the Company's proposed rate design does not reflect cost of service and shifts cost responsibility within the HLF rate class by charging customers demand-related costs through energy charges. As noted by Mr. Chriss, the use of energy charges to recover demand-related costs results in a shift in demand cost responsibility from lower load factor customers to higher load factor customers. As such, higher load factor customers would be paying for a portion of the demand-related costs that are incurred to serve lower load factor customers simply because of the manner in which the Company would be collecting those costs in rates. Mr. Chriss also noted that any concern related to a disproportionate impact on low load factor customers is not relevant because the HLF rate is specifically designed for high load factor customers and the Company has a low load factor rate option (Rate LLF) for customers that are not well suited to the HLF rate. Accordingly, Mr. 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. Mr. Chriss also provided an estimate of the charges that would result from his proposal, which he concluded would result in less rate shock for HLF secondary customers, would produce charges more consistent with how the costs proposed to be rolled-in to base rates from the Company's riders were recovered through those riders, and would result in more modest changes in total charges than the rate structure proposed by the Company.

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. <u>Petitioner's Rebuttal Evidence</u>. 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~~note that the impact of Walmart's and Kroger's ~~this~~ proposals ~~will have~~ on members of the rate class that have lower load factors is not a great concern. To that end, we are particularly persuaded by the evidence presented by Mr. Chriss and Mr. Bieber, as well as the testimony of Mr. Bailey at the evidentiary hearing, that Rate HLF and Rate LLF are specifically designed to provide benefits to high load factor customers and low load factor customers, respectively, for service under each of those rates. As such, even though there is some variance in load factors within the HLF class, the impact of Walmart's and Kroger's proposed changes to Rate HLF within the class would, by the Company's design, be minimal. Given the express design of the Company's tariff to provide separate beneficial rates to both low load factor customers and high load factor customer, we specifically agree with Walmart and Kroger that the use of energy charges to recover demand-related costs in the structure of Rate HLF improperly distorts the structure of that rate for customers who are, by nature, high load factor customers. That distortion results in a misallocation of cost responsibility within the class to the favor of lower load factor customers within that class and sends improper price signals to all HLF customers.

As noted in Kroger's brief, Kroger's and Walmart's proposed rate design reflects a cost-based difference that improves the alignment between charges and underlying costs while also mitigating potential intraclass rate impacts. Although this gradual movement will cause lower load factor customers to experience slightly greater rate increases than the class average, it will strike a balance between two important ratemaking principles – improving the alignment between rates and the underlying cost components while also employing gradualism. Kroger's and Walmart's proposal will not impact any customer group other than Rate HLF customers and it is revenue neutral to the Company. ~~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.~~

We are not persuaded by Petitioner's argument that its ~~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. As Mr. Bailey conceded at the hearing, and as Kroger noted in its brief, the Company uses "lower-than-42%-load-factor" customers, including 30% and 40% load factor customers, to support this argument. *See* Hearing Tr., p. C-84, lines 7-25. We agree with Kroger's argument that HLF Secondary customers with a load factor below 42% would likely be better off taking service under Rate LLF, and concerns about the rate impacts to these customers should not drive rate design decisions that will ultimately penalize the higher load factor customers that belong on Rate HLF. ~~"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.~~ The Commission recently recognized the importance of improving the alignment between demand and energy charges in its Order in the Indiana Michigan Power rate case (Cause No. 45235). In that case, we approved a rate design proposal similar in concept to that proposed by Walmart and Kroger in this case, finding that such a design would result in rates that are more closely aligned with the underlying cost components and send customers more efficient price signals. *See Indiana Michigan Power Company*, Cause No. 45235 (Order issued Mar. 11, 2020), p. 92. Accordingly, we find that ~~Company's~~ Walmart's and Kroger's proposal~~ed~~ to recover 100% of demand-related costs in Rate HLF to demand charges and to adust the HLF energy charge downward by a correspondening amount ~~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