ORIGINAL

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF INDIANA MICHIGAN POWER COMPANY, AN INDIANA CORPORATION, FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE, FOR APPROVAL OF: REVISED DEPRECIATION RATES; ACCOUNTING RELIEF; INCLUSION IN BASIC RATES AND CHARGES OF THE COSTS OF QUALIFIED POLLUTION CONTROL PROPERTY; MODIFICATIONS TO RATE ADJUSTMENT MECHANISMS; AND MAJOR STORM RESERVE; AND FOR APPROVAL OF NEW SCHEDULES OF RATES, RULES AND REGULATIONS.	CAUSE NO. 44075 APPROVED: FEB 13 2013

ORDER OF THE COMMISSION

Presiding Officers:
Kari A. E. Bennett, Commissioner
Jeffery A. Earl, Administrative Law Judge

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INTRODUCTION

On September 23, 2011, Indiana Michigan Power Company ("Petitioner," "Company" or "I&M") filed a Petition with the Indiana Utility Regulatory Commission ("Commission") seeking authority to increase its rates and charges for electric utility service and associated relief as discussed below. On September 23, 2011, Petitioner also filed its case-in-chief, workpapers and information required by the minimum standard filing requirements ("MSFRs") set forth at 170 IAC 1-5-1.

Petitions to Intervene were filed by Citizens Action Coalition of Indiana, Inc. ("CAC"), City of Fort Wayne ("Fort Wayne"), City of South Bend ("South Bend"), Steel Dynamics, Inc. ("SDI"), I&M Industrial Group ("Industrial Group"), the Kroger Company ("Kroger"), Inovateus Solar LLC ("Inovateus"), Ecos Energy ("Ecos"), and AEP Indiana Michigan Transmission Company, Inc. ("IM Transco"). All but one of these petitions were granted without objection. Ecos' petition was granted over I&M's objection.

On October 20, 2011, pursuant to notice given and published as required by law, the Commission held a Prehearing Conference and Preliminary Hearing. Petitioner, the CAC, Fort Wayne, South Bend, SDI, the Industrial Group, Kroger, Inovateus, Ecos, IM Transco, and the Indiana Office of Utility Consumer Counselor ("OUCC") appeared and participated in the hearing. On November 2, 2011, the Commission issued a Prehearing Conference Order in this Cause, which established a procedural schedule for this Cause and explained that the Commission would not be bound by the time constraints of the MSFR Rule because the procedural schedule proposed by the parties went beyond the deadline for an order to be issued under the MSFR Rule.

On February 2, 2012, Petitioner prefiled its supplemental direct testimony, exhibits and workpapers updating its rate base as of December 31, 2011. Pursuant to notice given and published as required by law, proof of which was incorporated into the record by reference and placed in the official files of the Commission, the Commission conducted an evidentiary hearing in this Cause from February 20, 2012, through February 28, 2012, at which time Petitioner presented its case-in-chief and its witnesses were cross-examined.

Pursuant to notice given and published as required by law, the Commission held public field hearings on April 23, 2012, in Fort Wayne, the largest municipality in Petitioner's Indiana service area, April 24, 2012 in South Bend, and on April 25, 2012, in Muncie. At the field hearings, members of the public were afforded the opportunity to make statements to the Commission. The OUCC filed additional written comments of members of the public several times throughout this proceeding.

On April 27, 2012, the OUCC and Intervenors filed their respective cases-in-chief. On May 25, 2012, the OUCC and Intervenors filed their respective cross-answering testimony and Petitioner filed its rebuttal testimony, exhibits, Major Project Update, and workpapers. On June 5, 2012, I&M filed its Submission of Omitted Rebuttal Exhibit and Correction to Rebuttal Testimony, and on June 13, 2012, I&M filed its Submission of Corrections to Rebuttal Testimony.

On June 13, 2012, the OUCC filed a Motion to Strike Portions of Petitioner's Witness David Moody's Rebuttal Testimony. On June 13, 2012, I&M filed its Petitioner's Response to Motion to Strike, and the OUCC filed its Reply to Petitioner's Response to Motion to Strike on June 22, 2012. The Presiding Officers denied the Motion to Strike at the evidentiary hearing on June 25, 2012.

The evidentiary hearing in this Cause continued from June 18, 2012, through June 28, 2012, at which time the OUCC and Intervenors presented their respective cases-in-chief and Petitioner presented its rebuttal evidence.

Based on the evidence presented and the applicable law, the Commission now finds:

1. **Notice and Jurisdiction.** Due, legal, and timely notice of the filing of the Petition in this Cause was given and published by Petitioner as required by law. Proper and timely notice was given by Petitioner to its customers summarizing the nature and extent of the proposed changes in its rates and charges for electric service. Due, legal, and timely notice of all public hearings in this Cause were given and published as required by law. I&M is a public utility as defined in Ind. Code § 8-1-2-1(a). Pursuant to Ind. Code § 8-1-2-42, the Commission has jurisdiction over Petitioner's rates and charges for utility service. Therefore, the Commission has jurisdiction over Petitioner and the subject matter of this proceeding.

2. **Petitioner's Organization and Business.** I&M, a wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP"), is a corporation organized and existing under the laws of the State of Indiana, with its principal offices at One Summit Square, Fort Wayne, Indiana. I&M is a member of the East Zone of the AEP System, which is operated on an integrated basis pursuant to the AEP Interconnection Agreement, a Federal Energy Regulatory Commission ("FERC")-approved agreement that defines the sharing of costs and benefits associated with certain AEP East Zone affiliates' respective generating plants ("AEP Interconnection Agreement"). I&M is engaged in, among other things, rendering electric service in the States of Indiana and Michigan. I&M owns, operates, manages, and controls plant and equipment within the States of Indiana and Michigan that are in service and used and useful in the generation, transmission, distribution, and furnishing of such service to the public. I&M has maintained and continues to maintain its properties in an adequate state of operating condition.

I&M provides electric service to approximately 458,000 customers in Adams, Allen, Blackford, DeKalb, Delaware, Elkhart, Grant, Hamilton, Henry, Howard, Huntington, Jay, LaPorte, Madison, Marshall, Miami, Noble, Randolph, St. Joseph, Steuben, Tipton, Wabash, Wells, and Whitley Counties in Indiana. I&M also provides retail electric service to approximately 128,000 customers in Michigan. In addition, I&M serves wholesale customers in Indiana and Michigan. I&M's electric system is an integrated and interconnected entity that is operated within Indiana and Michigan as a single utility. I&M's transmission system is under the functional control of PJM Interconnection, L.L.C. ("PJM"), a FERC-approved regional transmission organization ("RTO"), and is used for the provision of open access nondiscriminatory transmission service pursuant to PJM's Open Access Transmission Tariff ("OATT") on file with FERC. As a member of PJM, charges and credits are billed to AEP and allocated to I&M for functional operation of the transmission system, management of the PJM markets, and general administration of the RTO.

I&M renders electric service by means of electric production, transmission and distribution plant, as well as general property, equipment, and related facilities, including office buildings, service buildings and other similar properties which are used and useful in the generation, purchase, transmission, distribution, and furnishing of electric energy for the convenience of the public (collectively referred to as "Utility Property"). I&M's Utility Property is classified in accordance with the Uniform System of Accounts ("USOA") as prescribed by FERC and approved and adopted by this Commission.

3. **Existing Rates.** I&M's existing retail rates in Indiana were established pursuant to a settlement agreement that was approved in the Commission's order in Cause No. 43306 based upon test year operating results for the twelve months ended September 30, 2007, adjusted for fixed, known, and measurable changes. The petition initiating Cause No. 44075 was filed with the Commission on September 23, 2011. Therefore, in accordance with Ind. Code § 8-1-2-42(a), more than fifteen months has passed between I&M's last petition and I&M's most recent request for a general increase in its basic rates and charges.

4. **Relief Requested.** I&M originally requested authority to increase its rates and charges for electric utility service and approval of: revised depreciation rates; accounting relief; inclusion in basic rates and charges of the costs of Qualified Pollution Control Property ("QPCP"); modifications to rate adjustment mechanisms; a major storm reserve; and new schedules of rates, rules, and regulations. As shown by Petitioner's Exhibit SMK-R1, I&M requests an increase in annual revenues from basic rates of $169,550,883. After accounting for offsets and decreases in existing rate adjustment mechanisms, the Company's overall proposal results in a net annual increase in revenues of $170,131,845.

5. **Test Year.** As provided in the Prehearing Conference Order, the test year to be used for determining Petitioner's actual and pro forma operating revenues, expenses and operating income under present and proposed rates is the twelve months ended March 31, 2011, adjusted for changes that are fixed, known, and measurable for ratemaking purposes and that occur within twelve months following the end of the test year.

6. **Overview.** I&M's President and Chief Operating Officer, Paul Chodak III, provided a general overview of Petitioner's request and discussed the circumstances that led to I&M's request. He explained that from the end of the test year used to establish I&M's current rates (September 30, 2007) through November 30, 2011, I&M's capital investment to expand and improve its distribution, transmission, and generation facilities that are used to provide service to customers have increased on an Indiana jurisdictional basis by approximately $411 million. Consequently, the Company's earnings are currently below the authorized level.

Scott M. Krawec, I&M Director of Regulatory Services, explained that I&M's jurisdictional pro forma operating income at present rates is $74,700,720. This level is below the authorized return in the amount of $153,566,000 which was authorized in Cause Nos. 43306 and 43636.

The OUCC and Intervenors in the Cause did not agree with I&M's proposed rates and regulatory changes. The OUCC proposed an increase in I&M's rates to produce an additional

$27,740,964, a 2.14% increase. The Intervenors proposed a number of adjustments and opposed several of I&M's requests, all of which would act to lower the rate increase requested by I&M.

7. **Petitioner's Rate Base.**

A. **Original Cost.** The Indiana jurisdictional original cost of Petitioner's property used and useful in providing service to the public on December 31, 2011, was $2,185,361,368 and the Indiana jurisdictional net original cost rate base was $2,398,831,408. This calculation differs from Petitioner's proposed amount due to our treatment of the baffle bolt replacement at Cook Unit 2. Further, this rate base does not include Petitioner's investment of approximately $125 million in the new Cook Unit 1 turbine which was placed in service and became used and useful utility property on October 26, 2011. We discuss both of these issues below.

Michael D. Eckert, Senior Utility Analyst in the OUCC's Electric Division, proposed a net original cost rate base equal to $2,324,464,062. The difference from Petitioner's proposed net original cost rate base is that the OUCC (and SDI's Witness, Ralph C. Smith, Senior Regulatory Consultant at Larkin & Associates, PLLC) proposed to exclude from rate base the prepaid pension asset and the OUCC proposed inclusion of materials and supplies based on a 13-month average as opposed to the actual balance as of March 31, 2011. The Commission's findings on the disputed adjustments to rate base are discussed below.

(1) **Cook Unit 1 Turbine.**

(a) **I&M Case-in-Chief.** The Cook Unit 1 turbine replacement, which Mr. Krawec identified as a Major Project as that term is used in 170 IAC 1-5-1(l), was installed during the refueling outage and placed into service on October 26, 2011. Michael H. Carlson, I&M Vice President-Site Support Services at Cook Plant, estimated the cost for the turbine replacement to be $139 million (Total Company). The Company filed investment updates on a monthly basis in compliance with the Prehearing Conference Order in this Cause. As shown on Petitioner's Exhibit SMK-S1, the plant-in-service balance for the project through April 30, 2012 was $125,683,529 (Total Company). Mr. Krawec provided information in his direct testimony regarding the turbine replacement. He stated that the turbine replacement will take place during Unit 1's refueling outage and will be placed into service by October 2011. He said the turbine replacement is reflected in rate base at zero net plant value cost for purposes of earning return on this plant. He noted that I&M will update its rate base and depreciation prior to the evidentiary hearing if the final net costs of replacement differs from the estimate.

(b) **OUCC Case-in-Chief.** Mr. William W. Dunkel, a Principal of William Dunkel and Associates, noted that I&M's depreciation study excludes $21,610,932 in insurance proceeds received for Unit 1 Turbine Repair but that I&M did not exclude the retirements, cost of removal and other costs caused by the Cook Unit 1 fire. He stated that I&M intended to exclude costs caused by the Cook Unit 1 turbine fire, which occurred in 2008, and that the gross removal related to the Unit 1 Turbine Repair was not excluded from the net salvage analysis used in the depreciation study. In addition, the retirements related to the Unit 1 Turbine Repair were not removed from either the net salvage analysis or the interim retirement ratio calculations used in the I&M depreciation study.

Mr. Dunkel stated that the impact of these exclusions has two effects on the depreciation rates. By excluding the gross salvage, I&M increased the depreciation rates; by not excluding the cost of removal caused by the turbine fire, I&M did not make the adjustment that would lower the depreciation rates. Mr. Dunkel therefore concluded that the adjustment I&M made for the Cook Unit 1 turbine fire was not a balanced adjustment. He recommended that in addition to excluding the gross salvage related to this turbine fire, the associated cost of removal and retirements should also be excluded from the depreciation analysis in order to be fair and balanced. The depreciation rates he recommended properly excluded the retirement, gross salvage, and cost of removal amounts related to the turbine fire in Cook Unit 1. Mr. Dunkel concluded by recommending that the Commission apply his 1.72% depreciation rate to the Cook Unit 1.

(c) <u>I&M Rebuttal</u>. Mr. Krawec explained that in November 2011, consistent with Generally Accepted Accounting Principles ("GAAP"), I&M began recording depreciation expense associated with the new turbine and stopped recording depreciation expense associated with the old turbine. He testified that I&M is pursuing a settlement with its insurance provider, Nuclear Electric Insurance Limited ("NEIL"), concerning the turbine replacement, and that the pending insurance claim could ultimately impact the amount booked to net plant-in service for this investment. He testified that while it is appropriate to include the turbine investment in rate base in this case, I&M is willing to include only the incremental depreciation associated with this new investment in rates now and is willing to consider deferral of the return on rate base from this investment from the time the new rates established in this case go into effect until I&M's next rate case. Mr. Krawec explained that, under this proposal, the ultimate return that would be recognized for ratemaking purposes would be limited to the amount of the investment in the new turbine that is not covered by the final outcome of the NEIL insurance claim. Mr. Krawec stated the full amount of the investment in the new turbine should be included in rate base in this proceeding and I&M would "true-up" the actual return in its next base rate case reflecting the final outcome of the NEIL insurance claim if I&M is not granted accounting authority to defer the return on this unit.

Mr. Krawec testified that as of April 30, 2012, I&M's depreciation expense has increased by $2,014,184 (Total Company) or $1,302,274 (Indiana Jurisdictional) annually, due to the new turbine, as reflected on Petitioner's Supplemental Exhibit SMK-S1, Major Project Report. He clarified that the depreciation expense on the new plant will not be impacted by the outcome of the NEIL insurance claim. Thus it is appropriate to recognize the depreciation on this Major Project Update in the revenue requirement in this case.

The depreciation adjustments associated with Petitioner's major project update are shown on Petitioner's Exhibit A-R5, Depreciation and Amortization Adjustment No. R5, to remove depreciation expense associated with the previous turbine, and Depreciation and Amortization Adjustment No. R6, to add depreciation expense associated with the new turbine.

(d) <u>Commission Discussion and Findings.</u> Traditionally, plant investment is reflected in the ratemaking process through a return on the rate base additions and the associated depreciation expense is recognized in the utility's cost of service. As of the in-service date established in the record, the new turbine is used and useful in the provision of electric service. Therefore, it is appropriate to include the turbine investment in rate base in this case and to include the associated depreciation expense in the revenue requirement. However, in light of the pending insurance issues related to the NEIL insurance coverage, we find that Petitioner's proposal to defer the return on rate base from this investment from the time the new rates established in this case go into effect until I&M's next rate case is reasonable and should be approved. Accordingly, we find that the depreciation adjustments associated with the major project update shown on Petitioner's Exhibit A-R5, Depreciation and Amortization Adjustment No. R5, to remove depreciation expense associated with the previous turbine, and Depreciation and Amortization Adjustment No. R6, to add depreciation expense associated with the new turbine should be reflected in the revenue requirement used to establish basic rates. We further find and authorize I&M to defer the return on this rate base investment from the time the new rates established in this Cause go into effect until I&M's next rate case as proposed by Mr. Krawec. As proposed by Mr. Krawec, the ultimate return that will be recognized for ratemaking purposes will be limited to the amount of the investment in the new turbine that is not covered by the final outcome of the NEIL insurance claim.

(2) **Prepaid Pension Asset.**

(a) **I&M Case-in-Chief.** I&M's proposed rate base includes prepaid pension expense in the amount of $61,691,738 (Indiana Jurisdictional) as of March 31, 2011. I&M removed the balance applicable to non-utility operations costs from the Total Company amount but did not otherwise adjust the end of test-year level of this investment.

(b) **OUCC Case-in-Chief.** Margaret A. Stull, Senior Utility Analyst for the OUCC, opposed the inclusion of prepaid pension expenses in rate base. She testified that I&M's voluntary pension contributions do not represent an investment in used and useful utility plant and are not required to provide quality, reliable utility service to Indiana ratepayers. Ms. Stull recommended that if the Commission determines that I&M should receive some benefit from its voluntary pension contributions, it should only receive a debt return as a component of its revenue requirement based on the actual cost of debt incurred to fund the prepayments. Based on Ms. Stull's recommendation, Mr. Eckert removed $91,758,368 of prepaid pension expense on a total company basis and $61,691,738 on an Indiana jurisdictional basis from rate base.

Ms. Stull stated that prepaid pension expense refers to certain voluntary pension contributions Petitioner elected to make in addition to the annual pension contributions required by the Employee Retirement Income Security Act ("ERISA"). She noted the prepaid pension expense payments that Petitioner desires to include in rate base were substantially made in 2005 and 2010. Through discovery, Ms. Stull ascertained the dates and amounts of each year's pension contributions along with Petitioner's calculation of the prepaid pension expenses proposed to be included in rate base. Her review of this information led her to conclude that I&M did not make any contributions to its pension fund from 1993 through 2002 despite collecting funds for pension expense from ratepayers as part of I&M's revenue requirement during this same period. Ms. Stull also provided a table indicating no payments made in the years 2006, 2007, 2008, and 2009 despite the inclusion of funds in base rates for pension expense.

Ms. Stull asserted that including this proposed asset in rate base would require customers to pay a much higher interest rate (i.e., I&M's full cost of capital) than the much lower interest rate actually incurred by AEP to borrow the funds. She stated that I&M is allowed to earn a return on its investments in utility plant to insure safe, reliable utility service for Indiana ratepayers. She asserted that I&M should not be allowed to borrow funds at a low commercial paper rate, invest this cash into its pension fund, earn a full return on these additional pension contributions from its ratepayers, and then pocket the difference for its shareholders.

(c) SDI Case-in-Chief. Mr. Smith also opposed I&M's proposed inclusion of prepaid pension expense as an asset in rate base. Mr. Smith asserted that because I&M's 2011 FERC Form 1 shows that its pension benefit obligation is currently underfunded, I&M has a pension liability, which contradicts the Company's proposal to include in rate base the pension asset that resulted from voluntary management decisions. Claiming a pension asset in rate base when the Company's FERC Form 1 shows that the defined benefit plan is underfunded is inappropriate. Mr. Smith testified that there is a trend away from defined benefit plans and that including I&M's proposed pension asset in rate base could provide a disincentive for making reasonable reforms to the Company's pension plans that would reduce costs.

He stated pension funding levels are the result of discretionary AEP management decisions, and were anticipated to produce net savings based on AEP top management's assumption that the additional pension funding contributions would be financed using low-cost short term debt. Frequently, there is a wide range between the minimum funding required under ERISA and the maximum annual funding, the range typically limited by the maximum tax-deductible funding contribution limitations placed by the Internal Revenue Service ("IRS"). Increasing funding of a defined pension plan (pension trust contributions) would earn a return, which would then reduce future pension expense. Mr. Smith testified that making additional discretionary funding payments into the pension trust in amounts beyond ERISA requirements could potentially benefit employees and shareholders and result in additional costs to ratepayers.

Mr. Smith contended that pension expense associated with defined benefit pension plans should only be reflected in rate base as part of cash working capital based on a properly prepared lead-lag study, which has not been presented in this case. Mr. Smith argued that if the prepaid pension asset is to be included in the revenue requirement it should be based on a debt rate, preferably the rate for commercial paper. Mr. Smith testified that in 2011, I&M paid an average monthly interest rate of 0.407% on commercial paper, while its parent AEP (where the pension funding decisions were made) paid a weighted average interest rate of 0.51%. In comparison, the Company is requesting a pre-tax cost of capital of approximately 10.48%, which is 23.7 times higher than the 2011 commercial paper interest rate of 0.41%. Allowing the pension asset to be included in rate base would cost ratepayers $6.565 million. The discretionary decisions by AEP executive management to make additional contributions to the pension plan, which has led to the pension asset, increases the revenue requirement because the financing cost to ratepayers exceeds the pension savings, and are contrary to the rationale for the discretionary funding that was presented to the AEP board.

(d) I&M Rebuttal. Mr. Huge E. McCoy, Director of Accounting Policy and Research for the American Electric Power Service Corporation ("AEPSC") stated that the prepaid pension asset is not a new item but has been reflected on the Company's books since 2005 in accordance with the governing accounting standard. Mr. McCoy testified regarding the history and purpose of the prepaid pension asset as well as the associated accounting and ERISA standards. Mr. McCoy stated that the prepaid pension asset is properly defined as the cumulative amount of cash contributions to the pension trust fund beyond the cumulative amount of pension cost included in the cost of service used for ratemaking purposes. He disagreed with Ms. Stull's characterization of the additional pension contributions as voluntary or discretionary. He explained that although the additional pension contributions were not absolutely required as ERISA minimum contributions at the times they were made, if the additional contributions had not yet been made, ERISA would have required the Company to make the contributions. He explained that the Company began making contributions somewhat before they were absolutely required in order to even out such required contributions over several years and to minimize the total required contributions during this period because investment income on early contributions reduces the total funding requirement. Mr. McCoy pointed out that customers have benefitted because these additional contributions resulted in additional investment income in the pension trust and this in turn reduced pension cost that is recognized for ratemaking purposes.

Renee V. Hawkins, AEPSC Assistant Treasurer and Managing Director, Corporate Finance, explained that when the additional contributions were initiated, the Company was looking at mandatory pension contributions through the decade and chose to manage them with some discretion on the timing of the contributions. Ms. Hawkins identified the reasons that the pension fund contributions were made prior to the mandatory contribution date. The first reason was to manage the timing in order to fund when the cash is available to make the contributions instead of delaying until the contributions were mandatory under ERISA rules, at which point the company would have had no discretion on the timing of the funding. She explained either way, the contributions are necessary to meet the pension obligations. Second, having just experienced the 2008 and 2009 credit market freeze, Ms. Hawkins stated the Company preferred to be contributing to the pension when funds were available to avoid being in the position of having to fund the pension when either capital is not readily available or when the cost of capital is high. The third reason was to reduce the overall pension cost, as discussed by Mr. McCoy.

Mr. McCoy disagreed that the contributions should not be included in rate base. He stated that while the most obvious rate base item may be plant in service, rate base typically includes other property, such as working capital, fuel inventory, materials and supplies, and prepayments. Mr. McCoy explained his view that management should be encouraged to keep the pension plan operating smoothly so that it can legally meet its promised obligations. Mr. McCoy testified that as a result of additional pension contributions made after March 31, 2011, the pension plan was approximately 86% funded as of December 31, 2011. He explained that the additional pension contributions to the trust fund result in additional trust fund investment income that directly reduces annual Financial Accounting Standard ("FAS") 87 pension cost. He showed that the prepaid pension asset reduced 2011 pension cost by approximately $7.1 million versus the actual 2011 pension cost. He stated that if the Commission were to exclude the prepaid pension asset from rate base, the related $7.1 million pension cost savings also should be removed from cost of service so that customers will not receive the benefit from the additional contributions in the ratemaking process without the costs incurred by the Company to create that benefit also being reflected in the revenue requirement.

Mr. McCoy rebutted Ms. Stull's suggestion that the Company did not appropriately fund the pension trust from 1993 through 2002. He explained the final order in Cause No. 39314 was issued on November 12, 1993, so only a small portion of the year 1993 would apply to any analysis of historical ratemaking versus funding. Mr. McCoy also explained that pension cost is determined under FAS 87 for ratemaking purposes. In contrast, pension contributions are subject to ERISA and IRS requirements. As a result, it is unreasonable to expect the amount of pension cost and the amount of pension contributions to be equal. With regard to the 1993 through 2002 period to which Ms. Stull refers, Mr. McCoy stated that while it is true that the Company made no pension contributions, it is also true that total qualified pension plan cost for the period was slightly negative for this period.

Mr. McCoy clarified that I&M financed the pension contributions for its employees and retirees through cash payments that are reflected in I&M's capital structure. I&M's 2010 pension contribution was funded not with short-term debt but instead with available cash and neither the 2010 contribution nor the 2005 contribution were funded with commercial paper on an ongoing basis. He explained that the pension cost savings realized from the 2010 contribution were mainly due to reduced pension cost in subsequent years as a result of additional investment income on the 2010 trust fund contribution. According to Mr. McCoy, this pension cost savings and reducing the pension funding shortfall were the real reasons for making the 2010 contribution.

In response to Mr. Smith's claim that the Company has not demonstrated that it has a prepaid pension asset and that instead it has a net liability, Mr. McCoy explained that Mr. Smith has confused two separate items which properly are treated differently for ratemaking purposes: (1) the prepaid pension asset (accounted for in accordance with the provisions of FAS 87), which is the cumulative difference between cash pension contributions and pension cost included in the cost of service used to establish rates, and (2) the net funded position (accounted for in accordance with the provisions of FAS 158), which is the difference between the balance of pension plan trust assets and the pension benefit obligation. I&M's prepaid pension asset represents the cumulative amount of actual cash pension contributions beyond the cumulative amount of pension cost included in cost of service, which should be included in rate base in order to reflect the Company's cost of funds on the additional cash contributions.

Mr. McCoy also disagreed with Mr. Smith's claims that funding is discretionary and the inclusion of the prepaid pension asset in rate base could provide a disincentive for making reasonable reforms to the Company's pension plan. He explained that a prudent cash investment should not be excluded from rate base just because it was made before it was absolutely required. In addition, he testified that the prepaid pension asset represents contributions that, although they were discretionary at the time of the contributions, would have been required by now under ERISA without the earlier contributions. Mr. McCoy also pointed out that while Mr. Smith provided evidence that many companies have made changes to their pension plans, Mr. Smith did not claim that the Company's pension plan is too costly. Mr. McCoy stated that while Mr. Smith claims that including prepaid pension in rate base would provide a disincentive to making changes such as adopting a cash balance formula, he failed to recognize that the Company already made just such a change. He stated that since January 1, 2011, all Company employees have been earning their pension benefits only under the cash benefit formula.

Mr. McCoy responded to Mr. Smith's suggestion that the Company should eliminate or severely restrict its defined pension benefit plan. He stated that the Company's pension plan is a significant component of total employee compensation. He noted that the U.S. Government

Accountability Office report GAO-09-291, which Mr. Smith quotes, acknowledges that defined benefit pension plans are an important source of retirement income for millions of Americans. In Mr. McCoy's view, Mr. Smith's recommendation to eliminate the prepaid pension asset from rate base would increase unpredictability and would restrict management's ability to prudently manage its pension plan in the best interest of customers.

Mr. McCoy addressed Mr. Smith's recommendation that financing costs of the pension contributions should be included at a debt rate based on low-cost commercial paper as an alternative to including the prepaid pension asset in rate base. He explained that I&M's 2010 pension contribution was funded not with short-term debt but instead with available cash and neither the 2010 contribution nor the 2005 contribution were funded with commercial paper on an ongoing basis. Mr. McCoy pointed out that, like Ms. Stull, Mr. Smith incorrectly identified the savings that justified the Company's 2010 pension contribution as being based upon how the contribution was financed, when actually the savings mainly were due to reduced pension cost that resulted from the additional investment income produced by the 2010 trust fund contribution. Ms. Hawkins explained that cash flow from deferred income taxes was used to fund I&M's pension contribution. She explained that even if short term debt had been used to fund the contributions (as other subsidiaries across the AEP system initially did), this would not justify the exclusion of the prepaid asset from rate base. She explained that short-term debt is sometimes used to fund capital expenditures until a debt issuance or cash flows from operations are available to fund the asset. Because such assets are reflected in rate base, the prepaid pension asset should not be treated differently even if it had been initially funded with short term debt.

(e) <u>Commission Discussion and Findings.</u> The record reflects that the prepaid pension asset was recorded on the Company's books in accordance with governing accounting standards. The record also reflects that the prepaid pension asset has reduced the pension cost reflected in the revenue requirement in this case and preserves the integrity of the pension fund. Petitioner made a discretionary management decision to make use of available cash to secure its pension funds and reduce the liquidity risk of future payments. In addition, the prepayment benefits ratepayers by reducing total pension costs in the Company's revenue requirement. Therefore, we find that the prepaid pension asset should be included in Petitioner's rate base.

(3) <u>Materials & Supplies.</u>

(a) <u>I&M Case-in-Chief.</u> I&M adjusted its proposed rate base to eliminate $3,828,761 of materials and supplies ("M&S)" applicable to non-utility operations, i.e., River Transportation Division. Otherwise, I&M's proposed revenue requirement used the end-of-test-year M&S amount of $186,556,239 (Total Company) or $121,493,195 (Indiana Jurisdictional).

(b) <u>OUCC Case-in-Chief.</u> Mr. Eckert did not oppose I&M's proposed rate base adjustment to eliminate the M&S applicable to non-utility operations, but disagreed with I&M's proposal to use the M&S amount as of March 31, 2011, as the pro forma test year amount. He testified that he reviewed the M&S balances for the six-year period April 2006 through February 2012 and determined that the March 31, 2011 balance was the second highest amount and therefore was not representative of the test year. Using a 13-month average for the period March 2010 through March 2011, Mr. Eckert recommended the M&S balance to be included in rate base should be $178,075,379 (Total Company).

(c) **I&M Rebuttal.** Jeffrey L. Brubaker, AEPSC Director - Regulatory Accounting Services, testified that Mr. Eckert's proposal to use a 13-month average balance instead of the end-of-period balance in rate base is arbitrary. In Mr. Brubaker's view the 13-month average does not show that the end of period balance for the test year is unreasonable. Mr. Brubaker highlighted certain errors in Mr. Eckert's calculation of his proposed M&S Indiana jurisdictional adjustment. Mr. Brubaker noted that while Mr. Eckert indicated that the test year included four of the highest months over a six-year period, Mr. Eckert failed to recognize that the test year also contains five of the seven lowest monthly M&S balances in the 25-month period December 2009 through December 2011, and five of the twelve lowest monthly balances in the 33-month period April 2009 through December 2011. Based on this evidence, Mr. Brubaker concluded that Mr. Eckert's 13-month average balance results in an unreasonably low balance of M&S to be included in rate base. Mr. Brubaker explained that if the Commission uses a 13-month average balance, the appropriate period would be from December 2010 through December 2011 as this period would correspond with the rate base cutoff date in this Cause. Mr. Brubaker calculated the 13-month average balance of M&S in rate base for December 2010 through December 2011 to be $180,987,920, to produce a M&S Indiana jurisdictional adjustment of ($3,549,664). Nevertheless, Mr. Brubaker recommended the Commission reject Mr. Eckert's proposal to use a 13-month average and instead include the actual March 31, 2011 balance of M&S in rate base.

(d) **Commission Discussion and Findings.** We find that the appropriate M&S balance to include in rate base is the actual balance as of March 31, 2011, as adjusted to eliminate amounts applicable to non-utility operations. Traditionally, we rely upon actual end of test year or pro forma period balances to estimate a utility's expenses. The OUCC has not provided a sufficient basis for us to deviate from that practice. Thus, the amount of materials and supplies included in rate base is $186,556,239 (Total Company) or $121,493,195 (Indiana Jurisdictional).

(4) **Baffle Bolts.**

(a) **OUCC Case-In-Chief.** Ms. Stull raised an issue regarding the replacement of baffle bolts at Cook Unit Two. Ms. Stull explained that certain test-year costs are one-time expenditures that are not reasonably expected to occur in the future. She stated that the rates being set in this Cause should reflect Petitioner's normal, on-going annual revenues and expenses. Therefore, if an expense will not reasonably recur in the future, it should be eliminated from operating expenses included in the revenue requirement.

Ms. Stull believes that the test-year expenses related to the replacement of baffle bolts - $11,597,530 (Total Company) and $7,498,405 (Indiana Jurisdictional) - are non-recurring. According to Petitioner's response to a data request, baffle bolts are used to fasten baffle plates in place inside the reactor vessel. These plates provide structural support for nuclear fuel and also channel the reactor coolant through the core for heat removal. The original design at Cook included 832 baffle bolts. According to Ms. Stull, Petitioner stated that no baffle bolts have ever been replaced in Cook Unit One and that, prior to the test year, no baffle bolts had ever been replaced in Cook Unit Two. Petitioner also stated that baffle bolts are designed for a 40-year life and are not routinely replaced during the original life span of nuclear plants. Based on this response, Ms. Stull recognized that replacing baffle bolts is an uncommon occurrence and determined there is no reason to believe that baffle bolts will be replaced at the Cook Plant facility in the future. She noted Petitioner expensed, rather than capitalized, these costs because, according to Petitioner, the work associated with the baffle bolts was a repair activity.

Because Petitioner does not consider these to be capital costs and because these costs are not reasonably expected to recur in the future, Ms. Stull recommended eliminating most of these expenditures from test-year operating expenses. Ms. Stull proposed amortization of the cost of baffle bolt replacement over the remaining life of the Cook Plant Unit 2. She noted that Cook Plant Unit 2 is currently licensed through 2037 yielding a remaining life of twenty-five (25) years. Amortizing the total costs of baffle bolt replacement over twenty-five (25) years yields an annual cost of $463,901 (Total Company) and $299,936 (Indiana Jurisdictional). Removing total test year costs and adding back the annual amortization of those costs yields an adjustment of $11,133,629 (Total Company) and $7,198,469 (Indiana Jurisdictional).

(b) <u>I&M Rebuttal.</u> Both Mr. Chodak and Mr. Krawec responded to Ms. Stull's removal of test-year O&M expense incurred for the baffle bolt repair at Cook Unit 2. Mr. Chodak explained that the baffle bolt replacement was a reasonable and necessary cost of providing service, was prudently incurred at the Cook Plant during the test year to maintain safe operation of the nuclear plant, and is representative of future operations. Mr. Chodak said that while I&M may not be replacing the baffle bolts in its reactor vessel every year, there will be other emergent work that will occur going forward. Mr. Chodak clarified that while the cost of the baffle bolts were incurred during the test year, the Company continued to incur additional expense following the test year to inspect baffle bolts.

Mr. Krawec disagreed with Ms. Stull's recommendation that the baffle bolts be removed from I&M's test year expenses and amortized over the life of Cook Unit 2, explaining that should the Commission find that the baffle bolt replacement at Cook Unit 2 is an extraordinary one-time expense which is non-recurring in nature, this should not preclude I&M from recovering the cost in a timely manner through the ratemaking process. He testified that the baffle bolt replacement was not a capital addition and therefore should not be amortized over the life of Cook Unit 2. He also recommended that should the baffle bolt expense be removed from the test period annual expense, the cost of the baffle bolt replacement should be recognized for ratemaking purposes via amortization over a three-year period, which he explained is reasonable because it approximates the period of time that rates established in this Cause will be in effect. Mr. Krawec also testified that should the Commission approve recovery of the baffle bolt replacement expense over 25 years, the unamortized balance should be recorded as a regulatory asset and included in I&M's rate base in this Cause and subsequent general rate filings.

(c) <u>Commission Discussion and Findings.</u> The evidence shows that no baffle bolts have ever been replaced in Cook Unit One and, prior to the test year, no baffle bolts had ever been replaced in Cook Unit Two. The evidence also indicates that baffle bolts are designed for a 40-year life and are not routinely replaced during the original lifespan of a nuclear plant. In light of these facts, we find that the baffle bolts expense is a one-time expense that is not likely to recur, and therefore, the expense should be removed from

Petitioner's test-year operating expenses. This results in a reduction of Petitioner's test-year operating expenses of $11,133,629 (Total Company) and $7,198,469 (Indiana Jurisdictional).

However, we agree that Petitioner should be allowed to recover the costs associated with the baffle bolt replacement. Therefore, we authorize Petitioner to amortize the cost of the baffle bolt replacement over the remaining twenty-five year life of Cook Unit 2. This amortization yields an annual expense of $463,901 (Total Company) and $299,936 (Indiana Jurisdictional). In addition, we recognize that there is an unamortized portion of the expense identified by Mr. Krawec. Therefore, we find that the unamortized portion of the baffle bolt expense should be recorded as a regulatory asset and included in I&M's rate base in this Cause and subsequent general rate filings.

B. Original Cost Rate Base. Based upon the foregoing findings with respect to the proposed adjustments to rate base, the Commission finds that the net original cost rate base (Indiana Jurisdictional) for I&M is $2,398,831,408 and is calculated as follows:

Net Plant At Original Cost	$2,185,361,368
OPEB	$ 1,478,564
Prepaid Pension Expense	$ 61,691,738
Deferred Gain Rockport 2 Sale	$ (26, 201,384)
Fuel Stock	$ 47,809,575
Other Materials & Supplies	$ 121,493,078
Unamortized cost of baffle bolt replacement	$ 7,198,469
Original Cost Rate Base	$2,398,831,408

C. Fair Value.

(1) I&M Case-in-Chief. David C. Moody, Vice President, Shaw Consultants International, Inc. and Michael E. Green, Senior Executive Consultant with Shaw Consultants, presented testimony and exhibits concerning the valuation of I&M's plant and equipment.

Mr. Moody made a personal inspection of Petitioner's transmission, distribution and general plant for this valuation as well as for a previous valuation in 2007. His appraisal developed the value of Petitioner's electric plant in service as of March 31, 2011, on the basis of the cost to construct the property new less existing depreciation ("Current Cost"). He utilized accepted methodologies for such property valuation, including recognized source materials and cost indices, like the Handy-Whitman Index of Public Utility Construction Costs ("Handy-Whitman Index"), for application to the original costs by years of installation to obtain the Current Cost as of March 31, 2011.

Mr. Moody explained how he determined the depreciation allowances to be applied to Current Cost and noted that the allowances for depreciation constitute the differences between Current Cost and Current Cost less depreciation. For the Rockport Plant and Petitioner's other Production Plant, Mr. Moody's opinion of the depreciated Current Cost is based on the results of the market value appraisal conducted by Mr. Green.

Mr. Green, an Accredited Senior Appraiser in public utilities and Certified General Real Property Appraiser, developed the appraised value of Petitioner's electric production plant as of March 31, 2011, on the basis of the income approach. Mr. Green compared the results of the income approach to available comparable sales data as a test of reasonableness. The values indicated by the income approach were then used by Mr. Moody to measure accrued depreciation in the cost approach.

Mr. Green explained that an income approach valuation of an electric power generating plant is typically based on a discounted cash flow ("DCF") analysis. He stated that the DCF analysis requires a market study to develop a long-term forecast of plant performance, economic dispatch, market revenues, and variable operating expenses. It also requires a projection of operation and maintenance ("O&M") expenses and capital expenditures necessary to support the level of projected future operations. He added that market revenues minus O&M expenses, capital expenditures, and income taxes result in a forecast of future after tax cash flows which are then discounted back to present value at a market based after-tax weighted average cost of capital ("WACC").

Mr. Green discussed the market study used in his analysis, described the market where I&M's generating assets are located, discussed the major market drivers underlying an electricity market forecast, and identified the assumptions made by Shaw Consultants with respect to each of the major market drivers. This included a discussion of the reserve margins in PJM, the current supply mix in PJM, the types of new units expected to be built in PJM, and the impact that the project capacity additions and retirements will have on the resource mix over the 20-year projection period. Mr. Green also discussed the Shaw Consultant's forecast of future fuel and emissions prices, the capacity price forecast used and other aspects of his analysis.

Because there is not an active market for non-Production utility plant, Mr. Moody used indirect methods for determining depreciation for this plant. Mr. Moody discussed his determination of depreciation for the Production Plant, Transmission Plant, Distribution Plant, and General Plant and presented the overall results of his analysis. He concluded that the Current Cost of the electric plant in service at March 31, 2011, was $15,588,394,590 and the Current Cost less depreciation was $7,767,969,769.

To determine the fair value of the used and useful property, Mr. Moody proposed the Commission give weight to the net original cost of the property and to its net Current Cost. Mr. Moody stated that the two generally accepted indicators of fair value are the depreciated original cost and the cost to construct the electric properties new less existing depreciation. Mr. Moody stated that fair value is generally regarded as being a weighting of these two indicators.

Mr. Moody testified that original cost less depreciation is an account of actual historical investment reduced by annual accruals of depreciation. Mr. Moody explained that once the investment is made it does not vary over time except for the annual allowance for depreciation. In his view, it is analogous to long-term debt and preferred stock in that once the investment is made in plant, that specific amount of investment is fixed for the time it is in service, regardless of function or inflation. In contrast, the cost to construct the electric properties new less allowances for existing depreciation changes from year to year as price levels vary according to inflation or deflation. He said because existing depreciation (as opposed to accounting depreciation) varies according to advances in design and construction, and according to the use of the assets, the methodology he proposed for the calculation of fair value reflects the characteristics of the indicators in the same proportion as the provided capital used to construct the assets. In other words, a certain percentage of Petitioner's capital structure is made up of fixed obligations (debt, preferred stock, and no-cost capital) that are unaffected by inflation or the physical characteristics of the assets. Mr. Moody proposed that the fair value should reflect this same proportion of original cost less depreciation since it has the same unvarying characteristics. Another percentage of the capital structure, that is, the remainder after all fixed obligations are satisfied, consists of equity capital. He testified that the return on common equity is affected by yearly changes in inflation and by the physical operating condition of the assets, to the extent that the operating condition affects performance. He said this portion of the fair value should be weighted with a pro rata share of the Current Cost to construct the electric properties in service less existing depreciation because this indicator reflects the impact of the same phenomena.

Mr. Moody calculated the fair value based on the capital structure provided by Ms. Hawkins and the original cost less depreciation found on Petitioner's books and records. He stated that the cost to construct the electric properties new less existing depreciation is taken from the results of his appraisal. The result of this analysis for plant in service as of March 31, 2011 is as follows:

	Cost	Weight	Contribution
Original Cost Less Depreciation	$3,190,052,163	57.33%	$1,828,856,905
Current Cost Less Depreciation	$7,767,969,769	42.67%	$3,314,592,700
Fair Value Net Electric Plant, Total Company			$5,143,449,605
Net Electric Plant, Indiana Jurisdictional			$3,468,969,555

(2) **OUCC Case-in-Chief.** Edward R. Kaufman, Senior Analyst for the OUCC, raised issues that he contended call into question the reasonableness of Petitioner's estimated fair value rate base. First, Mr. Kaufman contended if Mr. Green's appraised (market) value includes any items that are expressly excluded from fair value, his market value exceeds fair value. For example, if the market value is based on a DCF (cash flow) analysis and that DCF analysis assumes electricity prices that exceed cost, then the model will produce excess profits and an inflated market value. Next, Mr. Kaufman argued that Mr. Green's estimated value for I&M's generating plant is hypothetical because his valuation is based on the value as stand-alone plants selling electricity into the PJM grid. He also argued that Mr. Green's estimated value is circular because it is intended to be used as an input to determine Petitioner's authorized rates, but those same rates charged for electricity are used to determine the plant value. With regard to Mr. Green's DCF analysis, Mr. Kaufman expressed a concern that the analysis assumes a dramatic increase in capacity prices and an increase in capacity revenue from Cook Unit 2 from 2014 to 2020. Mr. Kaufman also argued that the Commission should consider net demolition costs when determining Petitioner's fair value rate base. Mr. Kaufman criticized Mr. Moody's analysis because Mr. Moody did not adjust his results or otherwise recognize improvements in productivity that have occurred over the life of the assets. Mr. Kaufman claimed that because Mr. Moody's reproduction cost new less depreciation ("RCNLD") analysis did not include an offset or reduction for increases in productivity, his estimated fair value rate base is overstated.

(3) **Industrial Group Case-in-Chief.** Mr. Michael P. Gorman, Managing Principal of Brubaker & Associates, Inc., identified several material concerns about the accuracy of the Company's fair market value estimate. Mr. Gorman questioned the reliability of Mr. Green's DCF valuation for a number of reasons. First, Mr. Gorman testified that Mr. Green, in estimating the net-free cash flow for I&M's generating units, used market price estimates for power and natural gas that substantially exceed the current market price for those same commodities. If current market prices were used, Mr. Gorman testified, Mr. Green's analysis would produce lower net cash flows, and a lower fair value estimate. Mr. Gorman stated that Mr. Green's analysis appeared flawed because it does not reflect a reduction in generating output for units scheduled to undergo significant environmental retrofits. Mr. Gorman explained that to the extent Mr. Green overstated the energy generation from these units, he overstated the net-free cash and fair value of the assets.

Mr. Gorman also expressed concern that the reproduction cost less depreciation valuation conducted by Mr. Moody fails to reflect the current technological obsolescence of I&M's plant and equipment, I&M's plans to retire certain units, and the need to make capital expenditures in I&M's plant to keep it used and useful. This, Mr. Gorman testified, indicates that Mr. Moody's analysis overstates the fair value of I&M's rate base. For these reasons, Mr. Gorman testified that the valuation performed by Messers. Moody and Green is not reliable and not useful in estimating the Company's fair value rate base.

(4) **I&M Rebuttal.** Mr. Green responded to Mr. Gorman's criticism that the DCF valuation of the production assets is questionable because the market price estimates for power and natural gas over the period 2011 to 2014 reflected in the analysis substantially exceed the current market prices for these commodities today. Mr. Green noted that neither the date of the valuation (3/31/11) nor the veracity of the valuation estimate as of the date of valuation have been called into question. Rather, Mr. Gorman asserts that current market prices are much lower than those used by Mr. Green, and thus would produce material lower net cash flows and a lower fair value estimate. Mr. Green explained that commodity market prices change all the time. He stated that to assert that recent changes would produce materially lower cash flows and a lower fair value estimate without supporting calculations is an unsubstantiated hypothesis.

Mr. Green explained that his direct testimony included DCF analyses for each of I&M's generating plants based on forecasted market revenues developed using the Ventyx Market Analytics - Zonal Analysis market modeling software. He said the results of that market price forecast were then compared to the NYMEX Clearport Futures Energy and Natural Gas Prices for illustration. He stated Shaw Consultants never actually relied on the NYMEX futures prices in its DCF analyses because the AEP Dayton hub contracts are not actively traded, are not considered a substitute for a formal fundamental market analysis, and are not location specific.

Rather, the comparison was shown to corroborate, not supplant, the results of the market price forecast.

Mr. Green re-ran the Market Analytics – Zonal Analysis market model using updated inputs from the EIA Short Term Energy Outlook dated May 2012 and the EIA preliminary 2012 Annual Energy Outlook to gauge the effect of updated fuel prices on the valuation of I&M's production assets. He stated these 2012 EIA forecasts are one year later than the 2011 EIA forecasts used in the original market study. Substituting the updated fuel price forecasts, but retaining the original valuation date (3/31/11), resulted in a decreased valuation of merely 1%. Further, wholesale adoption of the most recent NYMEX forward prices would only result in a 7% reduction in the value of I&M's generation assets.

Mr. Green also responded to Mr. Gorman's observation that plant capacity factors in his analysis did not change sufficiently to accommodate planned environmental retrofits. He explained that the environmental retrofits planned for I&M's generating units do not require a change in operation for construction. They are constructed independently of plant operations. He stated that once the retrofit construction is complete, the retrofits are tied into the facility during normal shut down periods, resulting in minimum down time. This is true of both fossil units and nuclear units. He stated that when Shaw Consultants re-ran the Market Analytics – Zonal Analysis market model described above, the actual planned outage days for the 2015 tie-in were used in the model to explicitly capture the effect. He stated that the combination of updated fuel prices and the actual planned outage resulted in a change in valuation of merely -1%.

Mr. Green also explained that the DCF in Petitioner's Exhibit MEG-4 was based upon the most accurate, up-to-date projections available at that time. He said the Life Cycle Management project ("LCM") costs were not included in the DCF analysis because the scope of the project had not yet been determined. He added that it is not uncommon for plant operators to update and revise projections over time; however, the LCM project was not filed at the Commission until April 13, 2012, and has not yet been approved. Mr. Green stated that Mr. Gorman is correct in one respect; the capital expenditures for Cook Unit 1 and Cook Unit 2 in Petitioner's Exhibit MEG-4 do not contain the most recent projections for the LCM project. He testified that current AEP projections for 2012 through 2020 indicate incremental capital costs of $752 million over the original projections included in Petitioner's Exhibit MEG-4 while projected O&M costs are $315 million lower than those in Petitioner's Exhibit MEG-4, resulting in net increased costs of $437 million. He stated that after accounting for an assumed 55 MW increase in capacity at Cook Unit 2 beginning in 2016, the generation fleet value would be reduced from Petitioner's Exhibit MEG-4 by 10%. He said accounting for the updated market price projections discussed above the reduction from Petitioner's Exhibit MEG-4 would be 11%.

Mr. Green testified that Mr. Kaufman mixes concepts when he contends that the estimated value is intended to be used as an input to determine Petitioner's authorized rates, but those same rates charged for electricity are used to determine the plant value. Mr. Green explained that the revenues used to determine plant value are based on the competitive wholesale market for electricity. The wholesale market rates used to estimate plant value are projected over a long period of time into the future and vary considerably from one year to the next. He stated the production portion of Petitioner's retail electric rates is derived from a return on the fair value of Petitioner's property plus recovery of actual operating expenses which only varies as a consequence of rate proceedings. He said it would be utterly coincidental for projected market revenues in any given year to equal the Petitioner's production cost of service.

Mr. Green also addressed Mr. Kaufman's concern that capacity prices in the DCF increase and capacity revenues at Cook Unit 2 are significant compared to the after tax cash flow. He explained that Mr. Kaufman fails to point out any error in the capacity price forecast. Mr. Kaufman points out only that capacity prices show a dramatic increase over time, but he did not provide any analysis of the PJM Reliability Pricing Model ("RPM") or the market fundamentals that drive RPM pricing. Mr. Green explained a cursory inspection of the PJM website's description of the RPM reveals that it includes incentives that are designed to stimulate investment both in maintaining existing generation and in encouraging the development of new sources of capacity – resources that include not just generating plants, but demand response, and transmission facilities. He said the fact that capacity market prices are projected to equal net cost of new entry at the time when reserve margins signal the need for new resources should come as no surprise, given the construct of the market and the intent of the RPM.

Mr. Moody testified that the other parties' criticisms regarding the reliability of his reproduction cost new less depreciation valuations, including the conjecture that the analysis might not reflect the technological obsolescence of I&M's plant and equipment, are ill founded. First, by using a market-based approach to valuing the production plant, all losses in value for those assets are accounted for, including technological obsolescence. The definition of obsolescence (or any other loss in value) is ultimately determined by what sellers and buyers agree to in the market. He explained that the retirement of Units 1, 2, and 3 at Tanners Creek has nothing to do with technology and everything to do with the fact that the units are 60 years old or more, and the fact that they have simply reached the end of their economic useful lives. Second, with respect to non-production plant, the majority of I&M's investment is in facilities for which there has been little or no technological improvement for many years. These facilities include poles, towers, conductors, services, conduit, and line transformers. These non-production accounts make up over 86% of the investment on a Current Cost basis. He said, of the balance, by far the largest portion (an additional 12%) is in transmission and distribution substation equipment. Mr. Moody testified that although there has been incremental technological improvement in some types of substation equipment over the years, these improvements have not led to either lower cost or shorter lives for existing equipment. He stated as a result, it would be inappropriate to make any broad adjustment to the Handy-Whitman Index to attempt to adjust for technological improvement. He added that if he were to discover any equipment or classes of equipment that exhibited technological obsolescence, the appropriate approach would be to identify the exact nature of that obsolescence and to address it specifically.

Mr. Moody calculated the impact on the fair value analysis of the revisions Mr. Green made to the DCF analyses and showed that the revised analysis had an immaterial affect on the fair value analysis. Mr. Moody still believes that the fair value of I&M's property in service at March 31, 2011, is $5,143,499,605. He said the difference between his opinion and the result of using Mr. Green's revised analysis is 3.4%.

Mr. Moody also responded to Mr. Kaufman's reference to miscalculations that call into question the reasonableness of Petitioner's estimated fair value rate base. He explained that there is nothing in Mr. Kaufman's testimony that points to or discusses any errors in calculation.

Mr. Moody reiterated that the fair value he presented is not based only on net Current Cost, but reflects net original cost as well. Mr. Moody added that the reasonableness of the fair value rate base is corroborated by looking at the results in comparison to alternative methodologies used by the Commission in the past. He said, one alternative, which does not rely on varying gas or electricity prices, changing technology, or plant production factors, is to start with the most recently-allowed fair value rate base, make allowances for general inflation in the economy between the original fair value date and the date at issue, and to add net plant additions for the interim, producing an updated fair value. Mr. Moody showed that using this methodology, the fair value of the electric plant as of March 31, 2011 is $4,047,570,890 (Indiana Jurisdictional). He noted that using the methodology he proposed in this case, the fair value of I&M's plant allocated to retail service in Indiana in this case is approximately $3,468,970,000. He stated that when this fair value amount is considered in light of the result using the alternative methodology presented above, the fair value he presented in this case appears to be not only reasonable, but conservative.

Mr. Moody disagreed with Mr. Kaufman's contention that the fair value opinion is based on a hypothetical scenario that does not currently exist. He said the required steps for arriving at an opinion of market value are clearly laid out in the appraisal profession, and for properties that produce income, the most important step is to determine the purchase price that can be supported by the net present value of future economic returns. He explained that for this particular case, the estimated market value of the generation assets is based on a willing buyer/willing seller concept. Another way of expressing market value is "value in exchange." He stated the electricity prices used in the DCF model are market prices – they are the prices I&M would have to pay to replace the electricity produced by the generation assets. He stated that the value of the facilities is directly related to the value of the power they produce. He explained that it is unlikely that I&M would accept a price less than market value in a sale of the assets, or that the Commission would approve a sale at a below market price. He concluded the current use of the assets is irrelevant to the determination of market value.

Mr. Moody also responded to Mr. Kaufman's comments on the consideration of retirement costs. Mr. Moody explained that the cost of retiring a plant is not a rate base issue, but a depreciation recovery issue. He said, I&M's original cost (the other indicator for fair value in Mr. Moody's analysis) is net of depreciation and therefore does not contain an allowance for retirement costs. He said those costs are determined as part of the plant depreciation rate. Further, the market value of the generating plants presented in this case was based on the actions of participants in the market for generating plants. He explained that in that market, plants are not typically demolished. He said the site and much of the infrastructure is redeveloped as another, new plant site which has significant value. He said this value offsets any cost of removal of the portions of the plant not used by the purchaser.

Mr. Moody also responded to Mr. Kaufman's statement that if I&M's plant was reconstructed today it would be designed and constructed more efficiently and therefore would not be identical to the current system. He explained that this statement may or may not be true. He said Mr. Kaufman assumes this to be the case but offers no evidence as to the degree of difference in design or cost that would be the result of constructing the system today. Mr. Moody added that the existing system was constructed in response to the needs of customers as determined at the time of construction. He said under the "regulatory pact," I&M is required to meet the needs of all of its customers, even if it is a detriment to the efficiency of the existing system. He stated that I&M is promised an opportunity to recover these costs that were made in the public interest. He explained that adjustments to the original cost contribution to fair value are not adjusted for this piecemeal aspect and the fair value of the system should be consistent in this manner.

Mr. Moody also explained why it is not necessary to adjust his results for improvements in productivity as suggested by Mr. Kaufman. He testified that the Handy-Whitman Index reflects these by the nature of its development. Generally speaking, each index is made up of either two or three major components that drive the cost of the type of asset being trended. For example, the index for poles might be comprised of material (poles and cross arms), labor (skilled and common in some ratio), and vehicles. Mr. Moody stated that while it is true that there has been advancement in productivity in labor over the years due to the development of tools and supply systems, it also true that the same gains apply to the manufacture and delivery of manufactured materials. He said the same drivers that lower the relative cost of installation of poles (or any other asset) also lower the relative cost of converting raw materials into finished products. He explained that as long as the ratio of the costs of the constituents of the index remains relatively similar with respect to one another, the index is a valid representation of the total cost of purchasing and installing the asset. He said the same concepts apply to technology. Mr. Moody pointed out that the Indiana Department of Local Government Finance advocates the use of the Handy-Whitman Index for utility property, but does not require an adjustment for technology or productivity.

Finally, Mr. Moody clarified that the Current Cost less depreciation portion of the fair value indicator includes the effects of historical inflation; the original cost less depreciation does not reflect any inflation.

(5) Commission Discussion and Findings. Ind. Code § 8-1-2-6 requires the Commission to value a public utility's property at its fair value. In *Indianapolis Water v. Pub. Serv. Comm'n*, the court of appeals confirmed that a utility should be entitled to earn a fair return on the fair value of its rate base. 484 N.E.2d 635, 638-640 (Ind. Ct. App. 1985) (see also *Office of Util. Consumer Counselor v. Gary-Hobart Water Corp*, 650 N.E.2d 1201 (Ind. Ct. App. 1995)). "This Commission has routinely accepted RCNLD studies into the record and considered [them] as evidence in support of Petitioner's fair value." *South Haven Sewer Works, Inc.*, Cause No. 41903, 2002 Ind. PUC LEXIS 221, at *5 (IURC June 5, 2002). Our supreme court recognized that RCNLD is one of several reasonable valuation methods that can be used in determining fair value, stating:

> [T]he courts will not limit the Commission to any one or more methods of valuation, be it prudent investment, original cost, present value, or cost of reproduction. This court has held that cost of reproduction depreciated is a proper item to be considered under the statute in arriving at a fair value figure.

Pub. Serv. Comm'n of Ind. v. City of Indianapolis, 131 N.E.2d 308, 318 (Ind. 1956).

In *Indianapolis Water*, the court explained that a fair value determination is not an either/or proposition between original cost and reproduction cost, but derives from consideration of all legitimate value factors. 484 N.E.2d at 638-640. Therefore, there are a number of legitimate valuation methods that the Commission should consider in determining fair value, one of which is the RCNLD method. "[R]eproduction cost new less depreciation cannot be disregarded in fixing a valuation for rate making purposes." *Id.* at 640 (quoting *City of Indianapolis*, 131 N.E.2d at 325 (Emmert, J., concurring)). The court indicated that this observation is as pertinent today as in 1956. *Id.* at 640. We will give appropriate weight to the RCNLD of Petitioner's utility plant for purposes of our fair value finding.

Petitioner's proposed fair value of its utility plant weighs both net original cost and net Current Cost. I&M's proposed fair value of its plant allocated to retail service in Indiana in this case is approximately $3.469 billion (Indiana Jurisdictional). The OUCC, relying in part on Mr. Kaufman's challenges to Petitioner's calculations, proposed a fair value of no more than $2.9 billion (Indiana Jurisdictional). Mr. Gorman, on behalf on the Industrial Group also raised several concerns regarding Petitioner's fair value calculations. On rebuttal, Petitioner agreed that its calculations did not take into account the impact of the LCM project at the Cook plant. Mr. Green testified that accounting for the LCM project, with an accompanying increase in the Cook plant's output, and using updated pricing forecasts would reduce his fair value calculation by approximately 11%.

Giving due consideration to the evidence presented, we find that Petitioner's proposed fair value of its used and useful property is no more than $3.469 billion (Indiana Jurisdictional). When combined with the other factors relevant to fair value rate base, we find that Petitioner's fair value Indiana Jurisdictional rate base is determined as follows:

Fair Value Plant	$3,468,969,555
OPEB	$ 1,478,564
Prepaid Pension Expense	$ 61,691,738
Deferred Gain Rockport 2 Sale	$ (26,201,384)
Fuel Stock	$ 47,809,575
Other Materials & Supplies	$ 121,493,078
Unamortized cost of baffle bolt replacement	$ 7,198,469
Fair Value Rate Base Indiana Jurisdictional	$3,682,439,595

8. Fair Rate of Return and Net Operating Income.

A. Cost of Capital.

(1) I&M Case-in-Chief. William E. Avera, Ph.D., President of FINCAP, Inc., presented his assessment of the rate of return on equity ("ROE") for I&M. He also addressed the reasonableness of I&M's capital structure, considering both the specific risks faced by I&M and other industry guidelines, and supported a fair return on fair value rate base that is consistent with underlying regulatory standards and the guidance of the Commission. Dr. Avera conducted various quantitative analyses to estimate the current cost of equity, including: alternative applications of the DCF and the Capital Asset Pricing Model ("CAPM"); an equity risk premium approach based on allowed rates of return; and reference to expected earned rates of return for utilities.

Based on the cost of equity estimates indicated by his analyses, Dr. Avera evaluated I&M's ROE taking into account the specific risks and potential challenges for its jurisdictional electric utility operations in Indiana, as well as other factors (*e.g.*, flotation costs) that are properly considered in setting a fair rate of return on equity. Based on the results of his analyses and the economic requirements necessary to support continuous access to capital, Dr. Avera recommended a ROE for I&M from the middle of his 10.65% to 11.65% reasonable range, or 11.15%.

Dr. Avera noted that currently, I&M is assigned a corporate credit rating of "BBB" by Standard & Poor's Corporation ("S&P"), Baa2 by with Moody's Investors Service ("Moody's"), and BBB- by Fitch Ratings Ltd. ("Fitch). The S&P and Moody's ratings are identical to those assigned to I&M's parent, AEP, and the Fitch rating for AEP is one notch higher at BBB.

Dr. Avera pointed out that AEP plans to invest an additional $2.6 billion in utility assets during 2011 and $2.9 billion in 2012, while construction expenditures at I&M are anticipated to total approximately $305 million in 2011 alone. Dr. Avera testified that support for the Company's financial integrity and flexibility will be instrumental in attracting the capital required to meet these fund needs in an effective manner. Investors are aware of the financial and regulatory pressures faced by utilities associated with rising costs and the need to undertake significant capital investments and noted that both S&P and Moody's have observed that cost increases and capital projects, along with uncertain load growth, are a significant challenge to the utility industry. Investors are also aware that utilities, including I&M, are confronting increased environmental pressures that impose significant uncertainties and costs. He stated that while customers benefit from the advantages of fuel cost savings and diversity that nuclear power confers, investors associate nuclear facilities with risks that are not encountered with other sources of generation.

Dr. Avera also discussed the implications of recent capital market conditions. He explained that the financial and real estate crisis that the country experienced in late 2008 and 2009 led to unprecedented price fluctuations in the capital markets as investors dramatically revised their risk perceptions and required returns. As a result of investors' trepidation to commit capital, stock prices declined sharply while the yields on corporate bonds experienced a dramatic increase. Dr. Avera said that uncertainties surrounding economic and capital market conditions heighten the risks faced by electric utilities, which, as described earlier, face a variety of operating and financial challenges.

Dr. Avera presented a comparison of interest rates on long-term bonds to those projected for the next few years, showing that the cost of permanent capital will be higher in the 2012-2015 timeframe that it is currently. Dr. Avera explained that as a result, current cost of capital estimates are conservative, and likely understate investors' requirements at the time the rates set in this proceeding become effective. Dr. Avera discussed what these events imply with respect to the ROE for I&M. He stated the Company's capital structure must preserve the financial flexibility necessary to maintain access to capital even during times of unfavorable market conditions. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Because all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to invest and hold them. Thus, the required rate of return for a particular asset at any time is a function of the yield on risk-free assets and the asset's relative risk.

Dr. Avera testified that he did not rely on a single method to estimate the cost of common equity for I&M. In his opinion, no single method or model should be relied on by itself to determine a utility's cost of common equity because no single approach can be regarded as definitive. Therefore, he applied both the DCF and CAPM methods to estimate the cost of common equity, and considered the results of the risk premium and expected earnings approaches. In his opinion, comparing estimates produced by one method with those produced by other approaches ensures that the estimates of the cost of common equity pass fundamental tests of reasonableness and economic logic.

Dr. Avera also evaluated the reasonableness of I&M's requested capital structure and examined the implications of cost adjustment mechanisms for the Company's ROE. He concluded that a common equity ratio of approximately 52% represents a reasonable capitalization for I&M. He explained that the common equity ratio implied by I&M's capital structure is consistent with the range of book value capitalizations maintained by the proxy group of electric utilities, and falls below the average market value equity ratios for the proxy group, based on data at year-end 2010 and near-term expectations. He added that his conclusion is reinforced by the investment community's focus on the need for a greater equity cushion to accommodate higher operating risks and the pressures of funding significant capital investments, as well as the impact of off-balance sheet commitments such as I&M's obligations under operating leases.

(a) Comparable Risk Proxy Groups. Dr. Avera explained that application of the DCF model and other quantitative methods to estimate the cost of common equity requires observable capital market data, such as stock prices. The accepted approach to increase confidence in the results is to apply the DCF model and other quantitative methods to a proxy group of publicly traded companies that investors regard as risk-comparable. Dr. Avera's DCF analyses focused on a reference group of other utilities composed of those companies classified by Value Line as electric utilities with: (1) an S&P corporate credit rating of "BBB-" to "BBB+"; (2) a Value Line Safety Rank of "2" or "3"; (3) a Value line Financial Strength Rating of "B+" to "A"; and (4) a market capitalization of approximately $1.8 billion or greater. In addition, he eliminated four utilities that are involved in a major merger or acquisition. These criteria resulted in a proxy group composed of twenty-four companies, which he referred to as the "Utility Proxy Group."

Dr. Avera also applied the DCF model to a reference group of comparable risk companies in the non-utility sectors of the economy. Dr. Avera referred to this group as the "Non-Utility Proxy Group." Dr. Avera testified that consideration of the results for the Non-Utility Proxy Group makes the estimation of the cost of equity using the DCF model more reliable. He explained that the estimates of growth from the DCF model depend on analysts' forecasts. He stated that it is possible for utility growth rates to be distorted by short-term trends in the industry or the industry falling into favor or disfavor by analysts. He said the result of such distortions would be to bias the DCF estimates for utilities. He explained that because the Non-Utility Proxy Group includes low-risk companies from many industries, it diversifies away any distortion that may be caused by the ebb and flow of enthusiasm for a particular sector.

Dr. Avera's Non-Utility Proxy Group was composed of those U.S. companies followed by Value Line that: (1) pay common dividends; (2) have a Safety Rank of "1"; (3) have a Financial Strength Rating of "B++" or greater; (4) have a beta of 0.85 or less; and, (5) have investment grade credit ratings from S&P. He testified that these criteria provide objective evidence to evaluate investors' risk perceptions. Dr. Avera compared the overall risk of both proxy groups with I&M. This comparison indicated that investors would view the firms in his proxy groups as having risk comparable to I&M.

(b) Discounted Cash Flow Analyses. Dr. Avera explained that DCF models attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The cost of equity is the discount rate that equates the current price of a share of stock with the present value of all expected cash flows from the stock. Dr. Avera explained that rather than developing annual estimates of cash flows into perpetuity, the DCF model can be simplified to a "constant growth" form. Dr. Avera applied the constant growth DCF model to estimate the cost of common equity for I&M, which is the form of the model most commonly relied on to establish the cost of common equity for traditional regulated utilities and the method most often referenced by regulators.

Dr. Avera explained that the first step in implementing the constant growth DCF model is to determine the expected dividend yield for the firm in question. He explained that this is usually calculated based on an estimate of dividends to be paid in the coming year divided by the current price of the stock. He said the next step is to evaluate long-term growth expectations. In constant growth DCF theory, earnings, dividends, book value, and market price are all assumed to grow in lockstep, and the growth horizon of the DCF model is infinite. He noted that implementation of the DCF model is more than just a theoretical exercise; it is an attempt to replicate the mechanism investors used to arrive at observable stock prices.

Dr. Avera explained that historical growth rates are unlikely to be representative of investors' expectations for utilities. Structural and industry changes have led to declining growth in dividends, earnings pressure, and, in many cases, significant write-offs. Dr. Avera testified that while these conditions serve to depress historical growth measures, they are not representative of long-term expectations for the utility industry or the expectations that investors have incorporated into current market prices. Because past trends for utilities do not currently meet the requirements of the DCF model, Dr. Avera's DCF analysis did not reference historical growth rates. Instead, he focused exclusively on indicators of future growth in applying the DCF model.

Dr. Avera explained that while the DCF model is technically concerned with growth in dividend cash flows, implementation of this DCF model is solely concerned with replicating the forward-looking evaluation of real-world investors. In the case of utilities, dividend growth rates are not likely to provide a meaningful guide to investors' current growth expectations because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry. He explained that as a result of this trend towards a more conservative payout ratio, dividend growth in the utility industry has remained largely stagnant as utilities conserve financial resources to provide a hedge against heightened uncertainties. He stated that as payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from dividends to earnings as a measure of long-term growth. Dr. Avera testified that future trends in earnings, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations.

Dr. Avera explained that in constant growth theory, growth in book equity will be equal to the product of the earnings retention ratio (one minus the dividend payout ratio) and the earned rate of return on book equity. Further, if the earned rate of return and the payout ratio are constant over time, growth in earnings and dividends will be equal to growth in book value. Despite the fact that these conditions are seldom, if ever, met in practice, Dr. Avera testified that this "sustainable growth" approach may provide a rough guide for evaluating a firm's growth prospects and is frequently proposed in regulatory proceedings. Accordingly, while Dr. Avera believes that analysts' forecasts provide a superior and more direct guide to investors' growth expectations, he included the "sustainable growth" approach in his presentation for completeness.

Dr. Avera testified that in applying quantitative methods to estimate the cost of equity, it is essential that the resulting values pass fundamental tests of reasonableness and economic logic. Accordingly, DCF estimates that are implausibly low or high should be eliminated when evaluating the results of this method. Dr. Avera's application of the constant growth DCF model results in cost of common equity estimates for the Utility Proxy Group ranging from 9.5% to 11.5%. His analysis resulted in of common equity estimate for the Non-Utility Proxy Group ranging from 11.7% to 12.3%.

(c) **<u>Capital Asset Pricing Model.</u>** As explained by Dr. Avera, the CAPM is a theory of market equilibrium that measures risk using the beta coefficient. Assuming investors are fully diversified, the relevant risk of an individual asset (*e.g.*, common stock) is its volatility relative to the market as a whole, with beta reflecting the tendency of a stock's price to follow changes in the market. As Dr. Avera also explained, like the DCF model, the CAPM is a forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of investors' required rate of return, the CAPM must be applied using estimates that reflect the expectations of actual investors in the market, not with backward-looking, historical data.

Dr. Avera explained how he applied the CAPM to estimate a forward-looking estimate for investor's required rate of return from common stocks. He explained that because empirical research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect. He stated that according to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. The need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. To account for this, *Morningstar* (Ibbotson SBBI 2010 Valuation

Yearbook) has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity. Accordingly, Dr. Avera's CAPM analyses incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization for the respective proxy groups. He stated that the application of his forward-looking CAPM approach resulted in an unadjusted ROE of 10.9% for the Utility Proxy Group and an adjusted ROE of 11.7% when the size adjustment is incorporated. For the Non-Utility Proxy Group, Dr. Avera's forward-looking CAPM approach resulted in an average implied cost of common equity of 10.6%, or 10.3% after adjusting for the impact of firm size.

Dr. Avera explained that it is appropriate to consider anticipated capital market changes in applying the CAPM. Current bond yields are likely to understate capital market requirements at the time the outcome of this proceeding becomes effective. Accordingly, in addition to the use of current bond yields, he also applied the CAPM based on the forecasted long-term Treasury bond yields developed based on projections published by Value Line, IHS Global Insight, and Blue Chip. Dr. Avera explained that incorporating a forecasted Treasury bond yield for 2012-2015 implied an unadjusted cost of equity of approximately 11.2% for the Utility Proxy Group, or 12.0% after accounting for firm size. For the Non-Utility Proxy Group. Dr. Avera's application of the CAPM using a projected government bond yield resulted in cost of equity estimate of 10.9% and 10.6% before and after adjustment for firm size, respectively.

(d) Risk Premium Approach. The risk premium method of estimating investors' required rate of return extends to common stocks the risk-return tradeoff observed with bonds. The cost of equity is estimated by determining the additional return investors require to forgo the relative safety of bonds and bear the greater risks associated with common stock and by then adding this equity risk premium to the current yield on bonds.

Dr. Avera based his estimates of equity risk premiums for electric utilities on surveys of previously authorized rates of return on common equity. He said authorized returns presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order. He stated that such returns should represent a balanced and impartial outcome that considers the need to maintain a utility's financial integrity and ability to attract capital. Moreover, allowed returns are an important consideration for investors and have the potential to influence other observable investment parameters, including credit ratings and borrowing costs. Thus, this data provides a logical and frequently referenced basis for estimating equity risk premiums for regulated utilities. The rates of return on common equity authorized utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates and published in its *Regulatory Focus* report. Dr. Avera subtracted the average yield on public utility bonds from the average allowed rate of return on common equity for electric utilities to calculate equity risk premiums for each year between 1974 and 2010. Over this 37-year period, these equity risk premiums for electric utilities averaged 3.36%, and the yield on public utility bonds averaged 9.01%.

Dr. Avera said there is a capital market relationship that must be considered when implementing the risk premium method. He explained there is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. Accordingly, Dr. Avera explained, for a 1% increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have changed since the equity risk premiums were estimated.

Based on the regression output between the interest rates and equity risk premiums displayed in his exhibit, Dr. Avera testified that the equity risk premium for electric utilities increased approximately 41 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated on page 1 of Petitioner's Exhibit WEA-8, with the yield on average public utility bonds in July 2011 being 5.34%, he said this implied a current equity risk premium of 4.86% for electric utilities. Adding this equity risk premium to the average yield on triple-B utility bonds of 5.70% produces a current cost of equity of approximately 10.6%. As shown on page 2 of Petitioner's Exhibit WEA-8, incorporating a forecasted yield for 2012-2015 and adjusting for changes in interest rates since the study period implied an equity risk premium of 4.29% for electric utilities. Dr. Avera explained that adding this equity risk premium to the average implied yield on triple-B public utility bonds for 2012-2015 of 7.10% resulted in an implied cost of equity of approximately 11.4%.

(e) <u>Expected Earnings Approach.</u> Dr. Avera also evaluated the cost of common equity using the expected earnings method. He explained that reference to rates of return available from alternative investments of comparable risk can provide an important benchmark in assessing the return necessary to assure confidence in the financial integrity of a firm and its ability to attract capital. It avoids the complexities and limitations of capital market methods and instead focuses on the returns earned on book equity, which are readily available to investors. The concept underlying the expected earnings approach is that investors compare each investment alternative with the next best opportunity. If the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms.

Dr. Avera explained that the traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. He said the actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. While the traditional comparable earnings test is implemented using historical data taken from the accounting records, it is also common to use projections of returns on book investment, such as those published by recognized investment advisory publications *(e.g.*, Value Line). He stated that because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison.

Dr. Avera pointed out that regulators do not set the returns that investors earn in the capital markets - they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. Dr. Avera stated that this opportunity cost test does not require theoretical models to indirectly infer investors' perceptions from stock prices or other market data. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior. Dr. Avera testified that the average ROE indicated for electric utilities based on the expected earnings approach range from 10.5% to 10.7%.

(f) Flotation Costs. Dr. Avera testified that flotation costs are also relevant in setting the ROE for a utility. He explained that the common equity used to finance the investment in utility assets is provided from either the sale of stock in the capital markets or from retained earnings not paid out as dividends. When equity is raised through the sale of common stock, there are costs associated with "floating" the new equity securities. He said these flotation costs include services such as legal, accounting, and printing, as well as the fees and discounts paid to compensate brokers for selling the stock to the public. Also, some argue that the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds a utility nets when it issues common equity.

Dr. Avera stated that there is not an established mechanism for a utility to recognize equity issuance costs. He explained that while debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. He testified that equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment nor are flotation costs capitalized as an intangible asset. Thus, unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. He explained that because there is no accounting convention to accumulate the flotation costs associated with equity issues, these costs must be accounted for indirectly, with an upward adjustment to the cost of equity being the most logical mechanism.

Dr. Avera explained that while there are a number of ways in which a flotation cost adjustment can be calculated, one of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Dr. Avera noted that *New Regulatory Finance* concluded that: "The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue." He said, alternatively, a study of data from Morgan Stanley regarding issuance costs associated with utility common stock issuances suggests an average flotation cost percentage of 3.6%. Dr. Avera added that AEP incurred issuance costs equal to approximately 3.02% of the gross proceeds from its 2009 public offering of common stock. He testified that applying this 3.02% expense percentage to a representative dividend yield of 5.0% implies a minimum flotation cost adjustment on the order of 15 basis points.

(g) Impact of Rate Adjustment Mechanisms. Dr. Avera explained that the FAC and other rate adjustment mechanisms used by I&M do not warrant any adjustment in his evaluation of a fair ROE. He said investors recognize that I&M is exposed to significant risks associated with energy price volatility and rising costs and concerns over these risks have become increasingly pronounced in the industry. He said that while the FAC is supportive of the

Company's financial integrity, even for utilities with energy cost adjustment mechanisms in place, there can be a significant lag between the time the utility actually incurs the expenditure and when it is recovered from ratepayers. Thus, the FAC does not insulate I&M from the need to finance significant deferred power production and supply costs. He added that investors are also aware that the Company's fuel cost recovery may be adversely affected by the operating expense and return tests applicable to its FAC, which may result in an effective disallowance of fuel costs. He testified that the rate adjustment mechanisms do not imply that the Company's risks are lower than for other utilities in the nation or for those in the proxy groups used in his quantitative analysis. He explained that adjustment mechanisms and trackers have been increasingly prevalent in the utility industry in recent years. As a result, the mitigation in risks associated with such rate adjustment mechanisms is already reflected in the cost of equity range determined earlier. Similarly, Dr. Avera explained that the firms in the Non-Utility Proxy Group also have the ability to alter prices in response to rising production costs, with the added flexibility to withdraw from the market altogether.

(h) **Recommended ROE.** Dr. Avera said that considering the relative strengths and weaknesses inherent in each method, and conservatively giving less emphasis to the upper- and lower-most boundaries of the range of results, he concluded that the cost of common equity indicated by his analyses is in the range of 10.5% to 11.5%. After incorporating a minimum adjustment for flotation costs of 15 basis points to his cost of equity range, he concluded that a fair rate of return on equity for the proxy group of electric utilities is currently in the range of 10.65% to 11.65%.

Dr. Avera recommended a ROE for I&M at the midpoint of his reasonable range, or 11.15%. He stated recent challenges in the economic and financial market environment highlight the imperative of maintaining the Company's financial strength in attracting the capital needed to secure reliable service at a lower cost for customers. Dr. Avera explained that I&M faces significant risk due to its use of nuclear generation, the ongoing uncertainties related to future emissions legislation, and the need to provide an ROE that supports I&M's credit standing while funding necessary system investments. Dr. Avera testified that these considerations indicate that an ROE from the middle of his recommended range is reasonable. Dr. Avera added that I&M has distinguished itself in numerous measures of operating efficiency and effectiveness while maintaining moderate electric rates. Considering the Company's superior performance, Dr. Avera concluded that establishing a ROE of 11.15% for I&M is entirely consistent with regulatory economics.

(2) **OUCC Case-in-Chief.** Edward R. Kaufman presented the OUCC's proposed cost of equity ("COE") analysis.

(a) **Comparable Risk Proxy Groups.** Mr. Kaufman adjusted Dr. Avera's Utility Proxy Group to exclude four companies Mr. Kaufman did not consider reasonably comparable to I&M. Mr. Kaufman disagreed with Dr. Avera's use of a Non-Utility Proxy Group based on his view that the non-regulated companies do not share reasonably comparable risk with either Petitioner or the electric utility industry.

(b) **DCF Analyses.** To determine the current yield Mr. Kaufman used a three-month dividend yield of 4.23% and six-month average dividend yields of 4.27% from

AUS Utility Reports. He multiplied the current dividend yield by the one half year expected growth rate to convert the current yield to a forward yield. He also used a Value Line dividend yield of 4.34% for forward yields. When data was available, Mr. Kaufman used both historical and forecasted growth rates of earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS"). He used Value Line as his primary source of growth rates and reviewed forecasted growth in EPS from Zacks and Yahoo (Thomson Financial Network). Mr. Kaufman's estimate of growth using the Value Line data is 5.13%. His estimated growth rate using the forecasted growth in EPS is 5.30%. Mr. Kaufman excluded zero and negative growth figures to estimate growth but did not exclude low growth rates. To determine reasonableness, Mr. Kaufman compared his growth rate to the long-term historical trend in growth of EPS, DPS and BVPS.

Mr. Kaufman also performed a 2-stage DCF analysis, using an intermediate growth rate of 6.17% (Value Line forecasted growth in EPS) and a dividend yield of 4.25%. He assumed the first stage of the 2-stage DCF analysis would last 5 years and used a long-term growth rate of 4.75%. These inputs produced a 9.49% COE. Mr. Kaufman also competed a 2-stage DCF analysis using an average growth rate of 5.30% for the first stage (relying on averaged Value Line, Yahoo.com and Zacks' forecasted growth rates in EPS). This produced an estimated COE of 9.31%.

Mr. Kaufman's DCF model produced a range of estimates from 9.31% to 9.51%. Mr. Kaufman gave more weight to his single-stage DCF analysis, which used Value Line data, because he said it is based on a broader review of growth rates and he viewed it as most consistent with prior Commission decisions on how to estimate growth rates in a DCF analysis. Mr. Kaufman opined that analysts' forecasts of intermediate-term growth rates in EPS may be inflated and should not be used by themselves to estimate long-term growth in a DCF analysis.

Mr. Kaufman contended that a DCF analysis based exclusively or primarily on forecasted growth in EPS may overstate COE. He criticized Dr. Avera's use of a five-year investment horizon associated with analysts' forecasts in the DCF. Mr. Kaufman stated that even though investors may not intend to hold an investment beyond a given year, the DCF model requires a long term estimate of growth. In Mr. Kaufman's opinion, the Commission should give weight to both historical and forecasted data of growth rates because that is what the Commission has done in past rate cases. Mr. Kaufman acknowledged that Dr. Avera used sustainable growth in his fourth DCF analysis. He explained that he is uncomfortable using this methodology to estimate COE in a regulatory setting.

(c) CAPM Analysis. Mr. Kaufman believes that use of the geometric mean calculation to determine the CAPM risk premium is preferable over the arithmetic mean calculation because the geometric mean calculation more accurately measures the change in wealth over multiple periods. Mr. Kaufman stated that his CAPM analysis considered both geometric and arithmetic mean risk premiums. He also performed a second CAPM analysis using what he viewed as a forecasted market risk premium. He explained that because of the current economic environment and near record-low US Treasury rates, a forecasted risk premium may (at this time) not overstate the historical risk premium. To determine the risk-free rate, Mr. Kaufman gave the vast majority of his emphasis to long-term interest rates (30-year Treasury securities), some emphasis to intermediate-term interest rates (average of five-year and ten-year

Treasury securities) and no emphasis to results generated from the use of short-term interest rates (one year Treasury securities). Mr. Kaufman used 3-month and 6-month average yields in his CAPM to strike what he viewed as a balance between using current data while not relying on data that has become stale. Like Dr. Avera, Mr. Kaufman relied on Value Line as his source of beta. This resulted in an average beta of 0.728. Mr. Kaufman's CAPM analysis produced a range of COE estimates from 6.58% to 6.61% using an historical risk premium and a range of 6.83% to 6.87% using a forecasted risk premium.

Mr. Kaufman noted that Dr. Avera provided four CAPM analyses for his utility proxy group. Mr. Kaufman disagreed with Dr. Avera's market risk premium, his use of projected bond yields and his use of a size adjustment. Mr. Kaufman also noted that Dr. Avera's CAPM analysis in this case produced a higher COE than it did in a recent Michigan case.

(d) **Risk Premium Approach.** Mr. Kaufman did not conduct a risk premium analysis. He said he does not believe that using commission authorized COE is appropriate to estimate a required ROE. Mr. Kaufman also raised a concern about Dr. Avera's use of the forecasted bond yields from his CAPM analysis in his Risk Premium model. Mr. Kaufman also noted that Dr. Avera's 10.56% COE from his Risk Premium analysis was counterintuitive when compared to historical return in the S&P Public Utility Index.

(e) **Expected Earnings Approach.** Mr. Kaufman did not conduct an expected earnings analysis and raised a concern that Dr. Avera's analysis includes companies that Mr. Kaufman did not consider comparable to Petitioner.

(f) **Flotation Costs.** Mr. Kaufman acknowledged the Commission has typically allowed utilities to recovery measurable and reasonable flotation costs but considered it unnecessary to include a flotation cost adjustment for Petitioner at this time.

(g) **Impact of Rate Adjustment Mechanisms.** Mr. Kaufman did not make a specific adjustment to his COE estimate to recognize the influence of trackers. He explained to the extent that Indiana has trackers that are similar to those provided in other regulatory jurisdictions the effect of trackers is already captured by using an appropriately representative proxy group of state regulated electric utilities. In his view, the use of trackers calls into question the relevance of using a proxy group of unregulated companies.

(h) **Recommended ROE.** Mr. Kaufman explained that he gave additional weight to his Value Line DCF and CAPM analyses based on historical risk premiums. This produced an overall range of 6.58% to 9.51%. He believes that I&M's COE is near the high end of his range and recommended a COE of 9.20%. A COE of 9.20% results in a weighted cost of capital of 6.35%. He made no company-specific business risk adjustment. He made no adjustment to his estimated. Mr. Kaufman pointed to low inflation rates, a Duke University survey of estimated annual returns, and other forecasts as support for the reasonableness of his recommendation. Mr. Kaufman also argued that his estimated COE is supported by the expected average long-term rate of return on equities for Petitioner's Pension, OPEBs, and nuclear decommissioning study.

(3) **Industrial Group Case-in-Chief.** Mr. Gorman presented a rate of return analysis on behalf of the Industrial Group.

(a) **Comparable Risk Proxy Groups.** Mr. Gorman relied on the same Utility Proxy Group used by Dr. Avera with the exception of three utilities, which he excluded due to recent mergers and acquisition activities. Mr. Gorman urged the Commission to reject Dr. Avera's Non-Utility Proxy Group because it includes companies operating in various industries subject to risks that are different from those affecting I&M's utility operations.

(b) **DCF Analysis.** Mr. Gorman performed three versions of the DCF. Mr. Gorman relied on the average of the weekly high and low stock prices of the utilities in the proxy group over a 13-week period ended March 23, 2012. In his judgment, a 13-week average stock price is a reasonable balance between the need to reflect current market expectations and the need to capture sufficient data to smooth out aberrant market movements. In his constant growth DCF model, Mr. Gorman used the most recently paid quarterly dividend as reported in the Value Line Investment Survey.

Mr. Gorman explained that as predictors of future returns, security analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data. He said assuming the market generally makes rational investment decisions, analysts' growth projections are more likely to influence observable stock prices than growth rates derived only from historical data. For his constant growth DCF analysis, Mr. Gorman relied on a consensus, or mean, of professional security analysts' earnings growth estimates as a proxy for investor consensus dividend growth rate expectations. He used the average of analysts' growth rate estimates from three sources: Zacks, SNL Financial, and Reuters available on March 28, 2012.

Mr. Gorman also estimated a sustainable long-term growth rate for his sustainable growth DCF model. He said the data he used to estimate the long-term sustainable growth rate is based on the Company's current market to book ratio and on *Value Line's* three- to five-year projections of earnings, dividends, earned returns on book equity, and stock issuances. As shown in Industrial Group Exhibit MPG-6, page 1, the average sustainable growth rate for Mr. Gorman's proxy group using this internal growth rate model is 4.93%.

Mr. Gorman also conducted a multi-stage growth DCF model. For the first stage of his model, he relied on the growth projections from his constant growth DCF analysis. For the transition period, the growth rates were reduced or increased by an equal factor. For the long-term growth period, Mr. Gorman used 5.0% based on the assumption that each company's growth would converge on the projected growth for the U.S. GDP of 5.0%. He used the same 13-week stock price and the most recent quarterly dividend payment data in his multi-stage growth DCF analysis.

Mr. Gorman concluded a fair return on equity based on his DCF analyses is 9.50%. He reached this conclusion by placing primary emphasis on the results of his constant growth DCF model using analysts' growth rate forecasts and multi-stage growth DCF analysis, both rounded up to 9.50%.

Mr. Gorman criticized Dr. Avera's DCF analysis because it excluded DCF return produced by negative growth rates. Mr. Gorman testified that applying the multi-stage DCF version to Dr. Avera's utility group yields lowers the DCF returns.

(c) <u>CAPM Analysis.</u> Mr. Gorman performed a CAPM analysis using the Blue Chip Financial Forecast's projected 30-year Treasury bond yield of 3.80%. Mr. Gorman believes that the nominal risk-free rate (or expected inflation rate and real risk-free rate) included in a long-term bond yield is a reasonable estimate of the nominal risk-free rate included in common stock returns. Mr. Gorman used the proxy group average Value Line beta estimate of 0.75 in his CAPM analysis. He derived a forward-looking market risk premium estimate using an expected return on the market less the risk-free rate. He estimated the expected return on the S&P 500 by adding an expected inflation rate to the long-term historical arithmetic average real return on the market. Mr. Gorman also used a long-term historical average market risk premium estimate based on Morningstar's *Stocks, Bonds, Bills and Inflation 2012 Classic Yearbook* over for the period 1926 through 2011.

(d) <u>Risk Premium Approach.</u> Mr. Gorman performed a Risk Premium study by estimating the difference between the required return on utility common equity investments and U.S. Treasury bonds for each year over the period 1986 through 2011. His common equity required returns were based on regulatory commission-authorized returns for electric utility companies. Mr. Gorman also established the equity risk premium based on the difference between regulatory commission-authorized returns on common equity and contemporary "A" rated utility bond yields for the period 1986 through 2011. Mr. Gorman's risk premium analyses produced a return estimate in the range of 9.40% to 9.20%, with a midpoint estimate of 9.30%.

Mr. Gorman criticized Dr. Avera's Risk Premium analysis because it adjusted the actual equity risk premium to reflect an inverse relationship between interest rates and utility equity risk premiums. Mr. Gorman stated that this is not consistent with academic literature that finds that this relationship should change with risk changes and not simply changes to interest rates. He also contended that Dr. Avera's bond yields were stale and that his reliance on projected interest rates is highly problematic because recent interest rate projections have turned out to be wrong.

(e) <u>Expected Earnings Approach.</u> Mr. Gorman testified that Dr. Avera's expected earnings approach should be rejected. He stated that a comparable earnings analysis measures an accounting return on book equity and is not developed from observable market data and can differ significantly from the return investors currently require.

(f) <u>Flotation Costs.</u> Mr. Gorman urged the Commission to reject Dr. Avera's flotation cost adjustment on the grounds that it is not based on actual and verifiable costs.

(g) <u>Impact of Rate Adjustment Mechanisms.</u> Mr. Gorman testified that I&M's current tracker mechanisms, including the tracker for environmental cost recovery, allows for frequent rate changes to reflect the Company's increasing invested capital costs and this mitigates I&M's construction and operating risk and supports a lower return.

(h) **Recommended ROE.** Mr. Gorman recommended the Commission award Petitioner a ROE of 9.50%, based primarily on his DCF analysis, and an overall rate of return of 6.68%. Mr. Gorman explained that he placed less weight on his CAPM return estimates because he is concerned about the reliability of the results based on extremely low Treasury bond yields in today's marketplace. Mr. Gorman reviewed the S&P credit rating review for I&M. He testified that using the Company's proposed capital structure and assuming I&M earns his recommended 9.50% return, I&M's financial credit metrics are supportive of its current "BBB" utility bond rating.

(4) **South Bend Case-in-Chief.** Mr. Reed W. Cearley, an independent contractor, did not perform a DCF, CAPM or other COE analysis but offered his opinion that I&M's return on equity should be lower than, and certainly no higher than the ROE approved in its last rate case and suggested that I&M and its investors should tighten their belts by accepting a lower ROE.

(5) **I&M Rebuttal Evidence.** Dr. Avera explained that Mr. Kaufman's and Mr. Gorman's analyses and their resulting recommendations are flawed and should be rejected. Dr. Avera noted that the ROE in the Michigan settlement represents a reduction of allowed return from 10.35% to 10.2%. He explained that Mr. Kaufman proposes that the Indiana ROE be reduced from 10.5% to 9.2%. He emphasized that in recent years I&M has consistently fallen short of earning its allowed return.

Dr. Avera explained that Mr. Kaufman and Mr. Gorman recognize that I&M has relatively greater investment risk than other utilities. He showed that S&P ranks I&M as considerably higher in risk compared to other utilities. He noted that his direct testimony discussed the fundamental risk exposures that drive investors to regard I&M as a relatively risky utility, including its exposure to nuclear power and large capital needs. The end result is that I&M must offer investors a higher return than its peers to compete for capital. He explained that if the utility is unable to offer a return similar to that available from other opportunities of comparable risk, investors will become unwilling to supply the capital on reasonable terms. He added that for existing investors, denying the utility an opportunity to earn what is available from other similar risk alternatives prevents them from earning their opportunity cost of capital. He said in this situation the government is effectively taking the value of investors' capital without adequate compensation.

(a) **Expected Earnings Analysis.** Dr. Avera refuted Mr. Kaufman's and Mr. Gorman's position that the comparable earnings analysis he used is not a reasonable method for estimating a fair ROE for I&M. He explained that the traditional comparable earnings test identifies a group of companies that are believed to be comparable in risk to the utility. The actual earnings of those companies on the book value of their investment are then compared to the allowed return of the utility. He explained that while the traditional comparable earnings test is implemented using historical data taken from the accounting records, more recently it is implemented using projections of returns on book investment, such as those published by Value Line, which is a recognized investment advisory publication. He stated that because these returns on book value equity are analogous to the allowed return on a utility's rate base, this measure of opportunity costs results in a direct, "apples to apples" comparison. Dr. Avera noted that in a previous electric rate case Mr. Kaufman presented both a survey of authorized returns from *Public Utilities Fortnightly* to support the reasonableness of his independent study and a comparison of actual returns from CA Turner Report, which is directly analogous to Dr. Avera's expected earnings approach, but using historical earned return on equity instead of Value Line expected return.

Dr. Avera conducted expected earnings analyses on the proxy groups used by Mr. Kaufman and Mr. Gorman, which they accept as comparable in risk to I&M. Those results show that these companies are expected to earn substantially more than these witnesses are proposing to allow I&M. Similarly, Dr. Avera presented the authorized returns for both Mr. Kaufman and Mr. Gorman's proxy groups, and again the results presented prove to be higher than the ROEs Mr. Kaufman and Mr. Gorman are recommending for I&M in Indiana.

While he agreed that market-based models are certainly important tools in estimating investors' required rate of return, Dr. Avera testified that this in no way invalidates the usefulness of the expected earnings approach. He said a very simple, conceptual principle is that when evaluating two investments of comparable risk, investors will choose the alternative with the higher expected return. He stated if I&M is only allowed the opportunity to earn a 9.5% return on the book value of its equity investment, as recommended by Mr. Gorman, while other electric utilities are expected to earn an average of 10.5%, the implications are clear. Dr. Avera added that regulators do not set the returns that investors earn in the capital markets – they can only establish the allowed return on the value of a utility's investment, as reflected on its accounting records. As a result, the expected earnings approach provides a direct guide to ensure that the allowed ROE is similar to what other utilities of comparable risk will earn on invested capital. As long as the proxy companies are similar in risk, their expected earned returns on invested capital provide a direct benchmark for investors' opportunity costs that is independent of fluctuating stock prices, market-to-book ratios, debates over DCF growth rates, or the limitations inherent in any theoretical model of investor behavior.

(b) Comparable Risk Proxy Groups. Dr. Avera explained that while Mr. Kaufman and Mr. Gorman recommended returns near the top of their results from financial models, they did not look at the end result in terms of what other utilities are allowed to earn and are expected to be able to actually earn. Dr. Avera showed that Mr. Kaufman's recommended ROE for I&M would fall woefully short of what other utilities are expected to actually earn. Dr. Avera showed that assuming that I&M was expected to actually earn Mr. Kaufman's 9.2% recommended ROE, such a return would not produce an end result that would enable I&M to effectively compete with other utilities to attract capital because it falls far below the 10.0% return expected for Mr. Kaufman's proxy group. Dr. Avera added that in light of Mr. Kaufman's own testimony that I&M's risks warrant a higher return, this 10.0% benchmark represents a floor on a reasonable ROE for the Company.

Dr. Avera also showed that the expected earnings for Mr. Gorman's proxy group average 10.2%. Dr. Avera explained that because Mr. Gorman's recommended ROE falls far below what the utilities in Mr. Gorman's own proxy group are expected to earn, it violates the opportunity cost standard underlying a fair ROE and is insufficient to allow I&M an opportunity to attract capital on reasonable terms.

Dr. Avera explained that Mr. Kaufman and Mr. Gorman offer no meaningful criticisms of his use of a Non-Utility Proxy Group. Dr. Avera stated that Mr. Kaufman and Mr. Gorman dismiss out of hand Dr. Avera's analysis of the cost of equity for non-utility firms based only on the faulty premise that these companies have higher risk. He explained the implication that an estimate of the required return for firms in the competitive sector of the economy is not useful in determining the appropriate return to be allowed for rate-setting purposes is wrong and inconsistent with investor behavior. Dr. Avera explained that his direct testimony did not contend that the operations of the companies in the Non-Utility Proxy Group are comparable to those of electric utilities. He recognized that operating a worldwide enterprise in the restaurant, beverage, computer software, retail, or transportation industry involves unique circumstances that are as distinct from one another as they are from an electric or gas utility. But he said that investors consider the expected returns available from all these opportunities in evaluating where to commit their scarce capital. He explained that so long as the risks associated with his Non-Utility Group are comparable to I&M and other utilities the resulting DCF estimates provide a meaningful benchmark for the cost of equity.

Dr. Avera noted that neither Mr. Kaufman nor Mr. Gorman presented any objective evidence to support the contention that Dr. Avera's Non-Utility Proxy Group is riskier than I&M or Dr. Avera's proxy group of electric utilities. Dr. Avera presented an analysis that refuted Mr. Kaufman's and Mr. Gorman's claim, showing that the average corporate credit rating for the Non-Utility Proxy Group of "A" is higher than the "BBB" average for the Utility Proxy Group and I&M. Dr. Avera also showed that all of the firms in his Non-Utility Proxy Group have a Safety Rank of "1", which classifies them among the least risky stocks covered by Value Line. Meanwhile, the Safety Rank corresponding to the firms in his Utility Proxy Group and I&M is 3. Similarly, Dr. Avera showed the average beta value of 0.71 for the Non-Utility Proxy Group is less that the 0.74 average for the Utility Proxy Group and essentially identical to the value corresponding to I&M. Dr. Avera concluded that this review of objective indicators of investment risk demonstrates that, if anything, the Non-Utility Proxy Group could be considered somewhat less risky in the minds of investors than I&M or the common stocks of the proxy utilities.

(c) <u>Flotation Costs.</u> Dr. Avera explained there is no justification for ignoring flotation costs in the end result test. He explained that I&M has been and will continue to invest massive amounts of equity capital to serve the public and the earnings base of this equity is permanently reduced by the amount of past flotation costs. He stated that without a flotation adjustment, these legitimate costs of providing utility service will be excluded for ratemaking purposes and will further undercut I&M's ability to earn its authorized ROE.

(d) <u>Change in Bond Yields Following Date of Dr. Avera Analysis.</u> Dr. Avera explained that the drop in Treasury bond yields does not translate directly into lower equity costs for utilities like I&M. He explained that as Treasury yields push deeper into historical lows driven by investors' "flight to safety," stock markets have tumbled. He added that because I&M is on the more risky end of the utility spectrum, it is not completely clear that falling interest rates on U.S. Treasuries translate into significantly lower costs of equity for I&M. He observed that if such a simple relationship did indeed exist, cost of equity experts would add little value beyond regurgitating Treasury yields.

(e) Mr. Kaufman's DCF. Dr. Avera explained that Mr. Kaufman's DCF analysis is flawed because it uses growth rates Mr. Kaufman regards as reasonable rather than those used by investors. Dr. Avera explained that growth rates are an input, not the output of the DCF model. He said Mr. Kaufman goes about mixing historical growth rates and projected growth rates of earnings per share, dividends, and book value per share without regard to what investors may be actually expecting for growth today when they put their money down to buy a stock. Dr. Avera explained that in the case of utilities, growth rates in dividends per share ("DPS") are not likely to provide a meaningful guide to investors' current growth expectations because utilities have significantly altered their dividend policies in response to more accentuated business risks in the industry. Thus, past DPS growth measures are not representative of long-tern expectations for the utility industry. Dr. Avera explained that as payout ratios for firms in the utility industry trended downward, investors' focus has increasingly shifted from DPS to earnings as a measure of long-term growth. He stated that future trends in EPS, which provide the source for future dividends and ultimately support share prices, play a pivotal role in determining investors' long-term growth expectations. He said the fact that investment advisory services focus primarily on growth in EPS indicates that the investment community regards this as a superior indicator of future long-term growth. He added that to the extent there is any useful information in historical patterns, that information is incorporated into analysts' growth forecasts. He showed that Mr. Kaufman's analysis reflects a downward bias because he relies on historical dividends to predict dividend growth. Dr. Avera testified that the most reliable way to estimate the growth rate investors are actually using when they purchase a particular stock at a particular time is to reference publications used by investors and research on investor behavior as Dr. Avera did in his analysis. He noted that Mr. Gorman's testimony corroborates this view.

Dr. Avera identified studies that contradict Mr. Kaufman's position that analysts' projections are optimistic, but pointed out the key issue is that, regardless of their accuracy, investors rely on these projections. He explained that the fact that analysts' EPS projections may deviate from actual results does not hamper their use in applying the DCF model as Mr. Kaufman contends. He testified that investors, just like securities analysts and others in the investment community, do not know how the future will actually turn out. He said investors can only make investment decisions based on their best estimate of what the future holds in the way of long-term growth for a particular stock. Dr. Avera added that securities prices are constantly adjusting to reflect investors' assessment of available information.

Dr. Avera explained that while the projections of securities analysts may be proven optimistic or pessimistic in hindsight, this is irrelevant in assessing the expected growth that investors have incorporated into current stock prices. He said any bias in analysts' forecasts – whether pessimistic or optimistic – is irrelevant if investors share analysts' views. Dr. Avera noted that Value Line is a well-recognized source in the investment and regulatory communities that does not sell or underwrite securities.

Dr. Avera explained that Mr. Kaufman eliminated growth rates less than 1% but kept low growth rates based on the supposition that investors do not ignore them. Dr. Avera pointed out that Mr. Kaufman presented no evidence from investors to support this supposition. Dr. Avera explained that the proper inquiry is whether a growth rate produces a DCF estimate that clearly identifies it as an outlier that should not be used in estimating investors' required returns. Dr.

Avera showed that when Mr. Kaufman's DCF is corrected to eliminate illogical, low-end values, as well as high-end outliers, the implied COE ranges from 9.6% to 11.6% with the midpoint being 10.6% and an average of 10.4%. The average cost of equity implied by Mr. Kaufman's DCF analysis as adjusted by Dr. Avera based on analysts' growth projections was 9.9%.

Dr. Avera testified that there is no basis to assume that Mr. Kaufman's two-stage DCF model reflects investor expectations. Dr. Avera explained that the only relevant growth rate is the growth rate used by investors, whether it is "intermediate" or not. He explained that investors do not have clarity to see far into the future, and noted that Mr. Kaufman presents no evidence that investors evaluate the future based on the assumptions and data sources that were required to apply Mr. Kaufman's two-stage model. On the contrary, in the financial media one observes many references to 3-5 year earnings growth forecasts for individual companies and very few references to very long-term GDP forecasts. He said long-term GDP growth rates are simply not discussed within the context of establishing investors' expectations for individual firms. Dr. Avera explained why the two-stage model no longer fits the expectations that investors built into electric utility stock prices, and noted that FERC abandoned the two-stage DCF model and uses a constant growth model using earnings per share projections and sustainable growth, just as Dr. Avera did in his analysis.

(f) **Mr. Kaufman's CAPM.** Dr. Avera explained that Mr. Kaufman's CAPM results are flawed and should be ignored because they are based almost exclusively on historical rates of return, not current projections and thus fall woefully short of investors' current required rate of return. Dr. Avera explained that Mr. Kaufman did not attempt to develop a market risk premium using current capital market information. Rather, his Appendix C simply presented the results of various studies and surveys conducted almost exclusively in the past and long before recent dislocation in financial markets and the onset of recession.

Dr. Avera explained that the backward-looking approaches used by Mr. Kaufman incorrectly assume that investors' assessment of the relative risk differences, and their required risk premium, between Treasury bonds and common stocks is constant and equal to some historical average. Dr. Avera explained that the incongruity between investors' current expectations and requirements and historical risk premiums is particularly relevant during periods of heightened uncertainty and rapidly changing capital market conditions, such as those experienced recently. He said that as a result, there is every indication the historical CAPM approach used by Mr. Kaufman fails to fully reflect the risk perceptions of real-world investors in today's capital markets, and this in turn violates the standards underlying a fair rate of return by failing to provide an opportunity to earn a return commensurate with other investments of comparable risk.

Dr. Avera explained that the problem with the approach used by Mr. Kaufman is that, instead of looking directly at an equity risk premium based on current expectations – which is what is required in order to properly apply the CAPM – he undertakes an unrelated exercise of compiling a list of selected computations culled from the historical record. Average realized risk premiums computed over some selected time period may be an accurate representation of what was actually earned in the past, but they do not answer the question as of what risk premium investors were actually expecting to earn on a forward-looking basis during these same time periods. Similarly, calculations of the equity risk premium developed at a point in history –

whether based on actual returns in prior periods or contemporaneous projections – are not the same as the forward-looking expectations of today's investors, which are premised on an entirely different set of capital market and economic expectations.

Dr. Avera also explained that the risk premium that Mr. Kaufman derived from Ibbotson Associates' Data does not comport with what this publication reports. He showed that Ibbotson Associates (now *Morningstar*) computes the equity risk premium by subtracting the arithmetic mean income return (not the total return) on long-term Treasury bonds from the arithmetic average return on common stocks. In other words, *Morningstar* concluded that using only the income component of the long-term government bond return provides a more reliable estimate of the expected risk premium because investors do not anticipate capital losses for a risk-free security. Mr. Kaufman, however, calculated his equity risk premium using the total return for *Morningstar's* long-term government bond series. As a result, the equity risk premium Mr. Kaufman presents falls far below what his own data source reports and the resulting CAPM cost of equity estimate is understated. Dr. Avera showed that the most recent edition of Mr. Kaufman's source of historical realized rate of return data calculates the long-horizon equity risk premium by subtracting the arithmetic mean average income return on long-term Treasury bonds from the arithmetic mean average return on the S&P 500, resulting in an equity risk premium of 6.62%, versus the 5.7% value reported by Mr. Kaufman.

Dr. Avera also disagreed with Mr. Kaufman's view that geometric means provide a better measure of expected returns when applying Mr. Kaufman's historical CAPM. He explained that while both the arithmetic and geometric means are legitimate measures of average return, they provide different information. Each may be used correctly, or misused, depending upon the inferences being drawn from the numbers. The geometric mean of a series of returns measures the constant rate of return that would yield the same change in the value of an investment over time. The arithmetic mean measures what the expected return would have to be in each period to achieve the realized change in value over time. In estimating the cost of equity, the goal is to replicate what investors expect going forward, not to measure the average performance of an investment over an assumed holding period. When referencing realized rates of return in the past, investors consider the equity risk premiums in each year independently, with the arithmetic average of these annual results providing the best estimate of what investors might expect in future periods.

Dr. Avera explained that the issue is not whether both measures can be useful; it is which one best fits the use for a forward-looking CAPM in this case. He said one does not have to get deeply into finance theory to see why the arithmetic mean is more consistent with the facts of this case. The Commission is not setting a constant return that I&M is guaranteed to earn over a long period. Rather, the exercise is to set an expected return based on test year data. In the real world, I&M's yearly return will be volatile, depending on a variety of economic and industry factors, and investors do not expect to earn the same return each year. Dr. Avera commented that Mr. Kaufman's reference to geometric average rates of return provides yet another element of built-in downward bias in Mr. Kaufman's analysis.

(g) <u>CAPM Size Adjustment.</u> Dr. Avera stated that Mr. Kaufman's own source, *Morningstar*, recognizes the relationship between firm size and return. Yet, Mr. Kaufman failed to consider this factor. Dr. Avera explained that because empirical research indicates that the CAPM does not fully account for observed differences in rates of return attributable to firm size, a modification is required to account for this size effect. He explained that according to the CAPM, the expected return on a security should consist of the riskless rate, plus a premium to compensate for the systematic risk of the particular security. The degree of systematic risk is represented by the beta coefficient. Dr. Avera explained the need for the size adjustment arises because differences in investors' required rates of return that are related to firm size are not fully captured by beta. He stated that to account for this, *Morningstar* has developed size premiums that need to be added to the theoretical CAPM cost of equity estimates to account for the level of a firm's market capitalization in determining the CAPM cost of equity. Accordingly, Dr. Avera's CAPM analyses for Mr. Kaufman's proxy group incorporated an adjustment to recognize the impact of size distinctions, as measured by the average market capitalization.

Dr. Avera stated that application of the forward-looking CAPM approach resulted in an unadjusted ROE of 10.7% for the firms in Mr. Kaufman's proxy group, or 11.5% after adjusting for the impact of firm size. Dr. Avera showed that there is widespread consensus that interest rates will increase materially as the economy strengthens. He showed that incorporating a forecasted Treasury bond yield for 2012-2016 implied an unadjusted cost of equity of approximately 11.0% for the utilities in Mr. Kaufman's proxy group, or 11.8% after accounting for firm size.

(h) Mr. Gorman's DCF. Dr. Avera explained that Mr. Gorman applied the constant growth DCF model using forward-looking estimates of EPS growth based on consensus forecasts of securities analysts, as well as considering a sustainable growth rate. This is comparable to the method Dr. Avera used. Dr. Avera noted that Mr. Gorman recognized that in order to correctly apply the DCF model one must attempt to estimate investors' consensus about what the dividend or earnings growth rate will be and concluded that as predictors of future returns, security analysts' growth estimates have been shown to be more accurate than growth rates derived from historical data. Thus, Mr. Gorman and Dr. Avera agree that EPS growth forecasts represent a superior guide to investors' expectations.

However, Dr. Avera disagreed with Mr. Gorman's claims that each company's growth would converge to the projected growth for the US GDP of 5%. He stated that there is no link between Mr. Gorman's GDP growth rate ceiling and the actual expectations of investors in the capital markets, which are the determining factor in any analysis of a fair ROE. Dr. Avera explained that Mr. Gorman presents no meaningful information to suggest that investors share his view that growth in GDP must be considered the highest sustainable long-term growth rate. He said the industry-wide historical comparisons of utility sales growth and GDP cited by Mr. Gorman may be factually correct, but they do not address what Mr. Gorman identified as the fundamental requirement in estimating growth – the future expectations of investors. In fact, Mr. Gorman specifically noted the pitfalls associated with historical data in assessing investors' expectations of growth. Dr. Avera added that actual historical growth rates for firms in Mr. Gorman's own proxy group contradict the notion that long-term growth is constrained by GDP. For example, Value Line reports that OGE Energy achieved earnings growth over the last 10 years of 6.0%, Public Service Enterprise Group had 10-year EPS growth of 6.5%, while Sempra Energy's 10-year EPS growth rate was 8.0%. Dr. Avera testified that these values for Mr. Gorman's own proxy firms indicate that utilities can and do achieve long term growth that exceeds Mr. Gorman's ceiling. Contrary to Mr. Gorman's artificial constraint, it is entirely logical for investors to recognize the potential for certain companies to grow faster than the overall economy.

Dr. Avera identified computational errors that bias Mr. Gorman's multi-stage DCF cost of equity estimates downward. Dr. Avera explained that under Mr. Gorman's multi-stage DCF approach Mr. Gorman predicted the cash flows that would accrue to investors over the next 200 years. To arrive at his estimated cost of equity, Mr. Gorman used the internal rate of return ("IRR") function available in Microsoft's Excel spreadsheet program to determine the discount rate (*i.e.*, investors' required rate of return) that would equate these cash flows with the current market price of the stock. Dr. Avera stated that this IRR calculation, however, assumes that annual cash flows are received at the end of each year, which is inconsistent with the periodic dividend payments that investors receive and results in a downward bias in the implied cost of equity.

(i) **<u>Mr. Gorman's Risk Premium.</u>** Dr. Avera explained that Mr. Gorman's risk premium approach is not a reliable guide for a fair ROE for I&M because Mr. Gorman subjectively chose to truncate the data available to apply his risk premium approach by ignoring all observations prior to 1986 and such manipulation of the data runs counter to the assumptions underlying the study of historical risk premiums, as Ibbotson Associates has recognized. Dr. Avera concluded that by choosing a truncated time period for his risk premium study, Mr. Gorman unnecessarily introduces a subjective bias that taints his analysis and artificially lowers his results.

Dr. Avera discussed other flaws in Mr. Gorman's risk premium application. Dr. Avera explained that Mr. Gorman failed to incorporate the inverse relationship between interest rates and equity risk premiums in his analysis of historical authorized rates of return. Dr. Avera stated that there is considerable empirical evidence that when interest rates are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums are greater. He said this inverse relationship between equity risk premiums and interest rates has been widely reported in the financial literature. Dr. Avera explained that as shown on Mr. Gorman's Exhibit MPG-13, current interest rates are significantly less than those prevailing in the late 1980s and early 1990s. He said given that interest rates are currently lower than the average over Mr. Gorman's study period, current equity risk premiums should be relatively higher, which Mr. Gorman's analysis entirely ignores. Dr. Avera showed that when Mr. Gorman's risk premium approach is corrected to account for these factors the analysis results in a current cost of equity estimate for I&M of 10.32%, or 11.27% after incorporating projected bond yields.

(j) **<u>Mr. Gorman's CAPM.</u>** Dr. Avera explained that the fundamental difference between his CAPM approach and Mr. Gorman's is that, while Dr. Avera's analysis actually looked to the future return expectations of investors in the capital markets, Mr. Gorman's "forward-looking" CAPM was based almost entirely on historical data. Dr. Avera explained that the relatively small portion of Mr. Gorman's forward-looking market return constituting inflation was based on projected data, but the actual return on the market itself was completely backward looking. Thus, Mr. Gorman essentially presented two variants of a CAPM using historical data. Dr. Avera stated that neither one of these approaches is consistent with the assumptions of the CAPM because the CAPM seeks to determine the expected return, and is predicated on the forward-looking expectations of investors.

Dr. Avera also refuted Mr. Gorman's claim that Dr. Avera used a "highly inflated" forward-looking estimate of the market rate of return. He explained that the use of forward-looking expectations in estimating the market risk premium is well accepted in the financial literature. He stated that Mr. Gorman's criticism seems to hinge on the fact that this method produces an equity risk premium for the S&P 500 that is considerably higher than the historical benchmarks Mr. Gorman cites. Dr. Avera stated that estimating investors' required rate of return by reference to current, forward-looking data, as he has done, is entirely consistent with the theory underlying the CAPM methodology. He explained that the CAPM is a forward-looking model based on expectations of the future. As a result, in order to produce a meaningful estimate of required rates of return, the CAPM is best applied using data that reflects the expectations of actual investors in the market.

Dr. Avera showed that a forward-looking application of the CAPM approach implied an unadjusted result of 10.9% for Mr. Gorman's proxy group, and an adjusted ROE of 11.7%. Dr. Avera showed that incorporating projected bond yields implied an unadjusted cost of equity of approximately 11.2% for Mr. Gorman's proxy group, and an adjusted ROE of 12.0%.

(k) **Impact of Rate Adjustment Mechanisms.** Dr. Avera explained that there is no reason to adjust I&M's ROE. Dr. Avera explained that trackers do not change the fundamental regulatory requirement that a utility have a reasonable opportunity to recover its reasonable and necessary expenses plus a fair rate of return on investment. Trackers do not eliminate the main regulatory risk that concerns investors: that an expenditure or investment will be disallowed because it is deemed unreasonable, unnecessary, or imprudent. He stated that when recovery is in base rates, the utility may over or under recover its expenses based on how actual revenues and costs behave between rate cases. If an expense or investment is moved to a tracker, the utility normally forgoes the upside possibility of over-recovery but benefits from avoiding the down-side of under-recovery. He noted that while I&M has a number of trackers, so do the utilities in the Utility Proxy Group. Dr. Avera testified that the major storm reserve treatment does not alter the fundamental principle that I&M should be allowed to recover its reasonable and necessary expenses. The exposure to disallowance for storm restoration expenses found unnecessary, unreasonable, or imprudent remains. Moreover, provisions to recover major storm restoration expenses are common for electric utilities in the proxy group. Dr. Avera explained that the ability of a utility to recover costs via tracking mechanisms does not mean that unregulated companies are not comparable in risk because unregulated companies have the opportunity to change prices whenever they wish, including in response to an increase in production costs and can abandon a product or geographic area if it is unprofitable. He said unregulated companies do not risk disallowances by regulators, only the discipline of the marketplace.

(6) **Commission Discussion and Findings.** The record contains a number of different methods of estimating Petitioner's cost of common equity, resulting in COE recommendations ranging from 6.58% to 12.3%. Petitioner recommended an ROE of 11.15%, the OUCC recommended an ROE of 9.2%, and the Industrial Group recommended an ROE of 9.5%. The midpoint of the Parties' recommendations is 10.175%. We recognize 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.

In Petitioner's last rate order, we authorized an ROE of 10.5%. This amount was based upon a settlement agreement. Petitioner's recommended range of ROE begins at 10.65%. However, Dr. Avera adjusted the results of his analyses to account for firm size and flotation costs. We have often determined that these kinds of adjustments are inappropriate. The Commission will only allow flotation cost adjustments when they are based on verifiable actual costs so that the reasonableness and appropriateness of the costs may be examined. Dr. Avera provided only speculation that such costs will occur and an estimate of their impact on Petitioner's ability to earn its authorized ROE. If these adjustments are removed from Dr. Avera's calculations, Petitioner's Range begins at or slightly less than 10.5%, Petitioner's current ROE. We also note that Dr. Avera's recommended ROE in this case of 11.15% is 35 basis points lower than the 11.5% ROE he recommended in his case-in-chief in Petitioner's last rate case. Notwithstanding the actual values of Dr. Avera's recommendation, it is reasonable to view this change as a relative change in market expectation from one period to the next.

We also consider the effect of cost tracking and rate adjustment mechanisms in reducing Petitioner's earnings risks and attempt to properly reflect them in Petitioner's cost of equity. We note that earnings risk can be seen in both an absolute and a volatility context – the absolute context serves as an effective marker to provide investors with an understanding of the base line earnings available, while the volatility context relates to the ability of the company to perform under a range of real world operating conditions. 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 is to reduce the uncertainty of the earnings that an investor can expect.

Petitioner has a number of trackers in place currently, and we have generally continued such trackers in this Cause. We have also considered and approved certain new or revised mechanisms, each of which has the effect of reducing I&M's earnings risk exposure. For example, we have redesigned the OSS Margin Sharing Mechanism to allow I&M to share OSS Margins both above and below the imbedded amount. We have recognized the changing capacity sharing dynamic of the AEP East System by authorizing annual adjustments in the Capacity Tracker. We have addressed the uncertainty of major storm damage restoration expenses through the creation of a reserve account. These steps should reasonably be expected to reduce the uncertainty of earnings available to investors and should enhance Petitioner's ability to earn its authorized ROE. In light of this discussion, we conclude that a slight decrease in Petitioner's ROE from that authorized in its last rate case is appropriate.

Based on our discussion above, we find that a reasonable range for Petitioner's cost of equity is 9.5% to 10.50%, and when considering the quality of the company's management of its electric utility franchise, we conclude that a 10.2% ROE is fair and reasonable.

B. Overall Weighted Cost of Capital. Based on these findings and after giving effect to the ROE we authorized above, we find that Petitioner's capital structure and weighted cost of capital is as follows:

Description	Total Company Capitalization	Percent Of Total	Cost Rate	Weighted Cost Of Capital
Long Term Debt	$1,563,320,246	38.74%	6.33%	2.45%
Preferred Stock	$ 8,072,400	0.20%	4.58%	0.01%
Common Equity	$1,721,707,204	42.67%	10.20%	4.35%
Customer Deposits	$ 28,745,633	0.71%	6.00%	0.04%
ACC. DEF. FIT	$ 658,660,139	16.32%	0.00%	0.00%
ACC. DEF. JDITC	$ 54,720,445	1.36%	8.35%	0.12%
Total	$4,035,226,067	100.00%		6.97%

Based on the record we further find that the foregoing capital structure properly reflects the target capital structure for the period the rates authorized herein will be in effect. We accept I&M's proposal to establish its authorized net operating income by multiplying the overall weighted average cost by the original cost rate base and find that the overall weighted cost of capital should be considered, along with other factors, in deriving a fair return for Petitioner.

C. Fair Rate of Return.

(1) I&M Case-in-Chief. Dr. Avera recognized that most, but not all, utility rate proceedings apply the cost of capital to original cost rate base. However, Dr. Avera explained that in his consulting and teaching outside of the utility regulatory arena, the cost of capital concept is applied to investment bases other than original cost. He stated that a recent and widespread application of standard ROE methods to a rate base other than original cost in the regulatory arena is in the area of telephone regulation. He stated that the Federal Communication Commission ("FCC") established a method of setting rates for unbundled network elements pursuant to the Telecommunications Act of 1996. Dr. Avera testified that one of the methods used by the Arizona Commerce Commission has been to allow a fair return on the fair value increment that is equal to the long-term U.S. Treasury bond yield reduced by the expected inflation rate. He explained that while there are other alternatives that are logical and supported by the economic and financial literature, this method produces a lower adjustment than others and could be applied in this case to balance the interests of investors and customers. Dr. Avera testified that this minimal return on the fair value increment would allow I&M an opportunity to earn a return that is comparable to similarly situated entities. By adopting this approach, the Commission would properly use the fair return to the fair value increment as a tool to support I&M's continued financial resilience.

Dr. Avera explained that equity investors expect that they will benefit when the value of an investment rises above the price originally paid. Indeed, the expectation of an increase in investment value is one of the two sources of cash flow in the DCF model. He stated that for corporations in both the non-utility and utility sectors there is often a significant difference between the original cost (less depreciation) of equity investment as reflected on the balance sheet and the value that equity garners in the market as common stock. He said giving a reasonable measure of return to the fair value increment would provide a clear signal that the Commission is willing to use the regulatory tools at its disposal to support I&M's efforts to maintain investment grade ratings and improve its credit standing by improving its ability to earn its allowed return.

Dr. Avera testified that because the return from the fair value increment is not risk-free, risk-free Treasury bond yields are not an excessive benchmark. He added that the Company has consistently earned less than the allowed return due to attrition. Applying a risk-free Treasury bond yield adjusted for inflation would be entirely consistent with fair value standards and the need to ensure that the Company has a realistic opportunity to actually earn the allowed return (including on any fair value increment). Dr. Avera recommended a rate of return on the fair value increment of 1.72%. In arriving at his inflation-adjusted Treasury bond yield, he considered projected data from a variety of sources commonly relied on by investors and the financial community. He explained that the inflation forecasts ranged from 1.95% to 2.58%, depending on the source and the horizon of the forecast period. In calculating the inflation-adjusted risk-free Treasury rate, he employed the 2.58% upper limit of this range, which is both conservative and consistent with the source and maturity of the 30-year Treasury bond yields discussed earlier in his testimony. He said subtracting an inflation rate of 2.58% from the 4.3% average 30-year Treasury bond yield for July 2011 results in an inflation-adjusted risk-free return on the fair value increment of 1.72%.

As explained by Dr. Avera, the "fair value increment" reflected in I&M's proposed methodology for determining the fair return on fair value is the difference between I&M's original cost rate base and its fair value rate base as presented by Mr. Moody. Mr. Krawec explained that the first step is to determine the incremental fair value on Indiana jurisdictional net plant in rate base above the original cost of the same property. He said Mr. Moody calculated the Total Company net plant fair value and Ms. Caudill calculated the Indiana Jurisdiction amount. He explained that Ms. Caudill also calculated the Indiana jurisdictional original cost net plant in rate base. Mr. Krawec explained that next step is to apply the rate of return of 1.72% supplied by Dr. Avera to the increment and gross up the return for income taxes using the conversion factor supplied by Jeffrey B. Bartsch, AEP Director - Tax Accounting and Regulatory Support. To attempt to mitigate controversy and in the interest of affordability, while recognizing the need to maintain adequate financial strength to keep capital costs low, the amount of the fair value adjustment reflected in the Company's proposed revenue requirement is 50% of the computed fair value revenue requirement or approximately $17.989 million.

(2) OUCC Case-in-Chief. Mr. Kaufman testified that the Commission can provide Petitioner a reasonable return by multiplying the Company's weighted cost of capital by its original cost rate base. He noted that in Michigan I&M did not seek a fair value increment and argued Petitioner does not require a higher level of return in Indiana than it sought in Michigan. Mr. Kaufman stated that he is not convinced that an inflation adjusted risk-free rate of return is a meaningful number to estimate a fair rate of return. He explained that the Commission has found that historical inflation should be removed from the rate of return as it corresponds with the historical inflation included in the fair value rate base. He claimed Dr. Avera did not do this.

Mr. Kaufman explained that the Commission can provide Petitioner with a reasonable return without including a fair value increment in authorized rates. Mr. Kaufman asserted that by multiplying the Company's weighted cost of capital by its original cost rate base, the Commission can provide a reasonable return.

Mr. Kaufman recommended the Commission reject Petitioner's proposed methodology for determining a fair return on the fair value of its used and useful property. He testified that Petitioner has not demonstrated it needs a fair value increment. Other than vague concerns about sending a message to credit markets and offsetting anticipated attrition, Petitioner's testimony does not provide any evidence that it needs an incremental return to accomplish these ends. He said if the Commission feels compelled to make a fair value rate base finding that is other than original cost, the Commission should find that Petitioner's fair value rate base is no more than $2.9 billion and multiply that by a cost of capital that has 50% of historical inflation from it. In Mr. Kaufman's view, Petitioner's future capital needs, concerns about credit metrics and attrition do not create a need for a fair value increment.

(3) **Industrial Group Case-in-Chief.** Mr. Gorman testified that I&M's method of estimating a fair value increment does not produce a fair return on either a fair value rate base or an original cost rate base. Rather, Mr. Gorman testified, I&M's proposal to use a fair value operating income adder simply produces an inflated rate of return on the Company's rate base. Mr. Gorman opined that the resulting earnings would be excessive and unjust, resulting in rates that would provide excessive compensation and would therefore be neither just nor reasonable.

(4) **I&M Rebuttal.** Dr. Avera explained that the Company's requested fair value increment would not allow I&M to earn a higher ROE than required by original cost ratemaking. He explained the purpose of the fair value increment is to allow I&M an opportunity to actually earn the allowed ROE. He stated that Indiana is a fair value state so the Commission has the authority to use fair value to meet regulatory objectives. He added that in this case, the fair value increment can be used to address this problem. Given the Company's low bond rating and challenging capital investment needs, Dr. Avera viewed the persistent under earning as a threat to I&M's credit standing and financial integrity. He explained that contrary to Mr. Gorman's claim that the fair value increment would provide an "excessive earnings opportunity," the proposed increment would only serve to give I&M the same opportunity to actually earn its allowed return as its investor-owned electric utility peers in Indiana and the rest of the country. In words the authorized net operating income would be equivalent to the allowed return on original cost rate base.

Dr. Avera disagreed that the net operating income should be the same between using original cost rate base and fair value rate base. He explained that would make the requirement to consider fair value meaningless and would not solve the problem facing I&M of persistently being unable to earn its authorized return. He concluded that the fair return on fair value is an appropriate regulatory tool for providing I&M an effective opportunity to earn an ROE that meets the end result test in Indiana.

(5) **Commission Discussion and Findings.** In *Duquesne Light Co. v. Barasch,* the Supreme Court held that the U.S. Constitution does not require the adoption of a

single theory of valuation. 488 U.S. 299, 316 (1989). "The Constitution within broad limits leaves the States free to decide what ratesetting methodology best meets their needs in balancing the interests of the utility and the public." *Id.* Indiana has selected the fair return on fair value rate base ratemaking methodology. The Supreme Court described the fair value approach as follows:

> Under the fair value approach, a "company is entitled to ask ... a fair return upon the value of that which it employs for the public convenience," while on the other hand, "the public is entitled to demand ... that no more be exacted from it for the use of [utility property] than the services rendered by it are reasonably worth." In theory the *Smyth v. Ames* fair value standard mimics the operation of the competitive market. To the extent utilities' investments in plants are good ones (because their benefits exceed their costs) they are rewarded with an opportunity to earn an "above-cost" return, that is, a fair return on the current "market value" of the plant. To the extent utilities' investments turn out to be bad ones (such as plants that are canceled and so never used and useful to the public), the utilities suffer because the investments have no fair value and so justify no return.

Id. at 308-309 (quoting *Smyth v. Ames,* 169 U.S. 466, 547 (1898)).

As we have in previous rate orders, we will use the following standards and criteria to determine a fair rate of return on Petitioner's investment in its utility plant:

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

(2) Return sufficient to ensure confidence in the financial integrity of the Petitioner;

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

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

One recognized method for evaluating the reasonableness of a utility's allowed return involves investigation of the utility's capital structure. From such investigation, we can develop the overall weighted cost of capital. This cost of capital may then be considered in determining a fair return. Having previously determined that the fair value of Petitioner's rate base is $3,675,241,126 (Indiana Jurisdictional), it is now our duty to determine a fair rate of return that can be used to calculate a fair dollar return for Petitioner's net operating income.

As our supreme court determined in *City of Indianapolis*:

> 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.

131 N.E.2d at 318. Therefore, 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.

We find that Petitioner's fair rate of return on the Company's fair value rate base can be determined by multiplying its fair value rate base by the weighted average cost of capital minus inflation. We determined above that Petitioner's weighted cost of capital is 6.97%. Using an inflation rate of 2.43%, we conclude that an appropriate authorized rate of return is 4.54%. Applied to the Company's fair value rate base of $3,682,439,595 (Indiana Jurisdictional), this produces an NOI of $167,197,805.

All Parties who presented evidence to determine Petitioner's NOI calculated the NOI on the basis of original cost ratemaking. Petitioner has not asserted that its calculated NOI using an original cost rate base represents an inadequate return on its investment. Rather, Petitioner requests a fair value increment, which is essentially a built-in boost to revenues to give it a heightened opportunity to earn its authorized return.

The purpose of a general rate case is to set rates that are fair, just, and reasonable, and which give the utility an opportunity to earn a return of, and return on, its investment, while not being so high as to constitute a taking from ratepayers. Once the Commission has determined Petitioner's reasonable expenses and revenues and calculated a fair ROE, we authorize an increase in Petitioner's rates to give Petitioner a reasonable opportunity to earn its authorized return. Petitioner then bears the burden of operating in an efficient manner to achieve its authorized return. To the extent that changing circumstances result in increased costs or decreased revenues, Petitioner has several cost and revenue tracking mechanisms in place to address such fluctuations, and the Company has the opportunity to return to the Commission for new rates and charges.

Petitioner's fair value increment proposal, when applied to an original cost rate base, artificially inflates the Company's rates by arbitrarily increasing the amount of revenues Petitioner is authorized to collect above that already calculated to provide a reasonable opportunity to earn its authorized return. Petitioner argues that it has traditionally under earned its authorized return. However, a utility is not entitled to a guarantee that it will earn its return. Rather, a utility is only entitled to a reasonable opportunity to earn a return on, and of, its investment. Therefore, we reject Petitioner's fair value increment proposal.

9. Operating Results At Present Rates.

A. Undisputed Pro Forma Adjustments. I&M proposed a number of pro forma adjustments to its test year revenues and expenses that were accepted by the other parties. All of the undisputed pro forma adjustments proposed by I&M have been fully identified in the record and are accepted even though they may not be specifically discussed in this Order. The disputed adjustments are discussed below.

B. Disputed Pro Forma Revenue Adjustments.

(1) Off System Sales Margins.

(a) I&M Case-in-Chief. As explained by Mr. Chodak and Mr. William J. Pascarella, Director of Generation Load Forecasting at AEPSC, Off System Sales ("OSS") margins are the revenues I&M is allocated from certain non-firm wholesale sales and other financial transactions made by AEP's Commercial Operations business unit. Making off-system sales is a wholesale business and not a retail service. Mr. Chodak testified that AEP is actively engaged in the competitive wholesale marketplace and brings considerable resources and expertise to bear in order to manage the attendant risks. As explained by Mr. Pascarella, AEPSC Director - Generation Load Forecasting, many off-system sales are not linked to physical assets (i.e., surplus generating capacity) but rather are based on purely financial transactions.

Mr. Krawec explained that I&M proposes to continue OSS margins sharing between customers and the Company through the OSS Margin Sharing Rider. However, I&M proposes that the revenue requirement used to establish basic rates for retail service not be artificially adjusted downward by OSS margins. I&M proposes that all OSS margins be shared 50/50. Under I&M's proposal, the Company will continue to have an incentive to optimize assets and pursue opportunities in the wholesale market for electricity, and I&M customers will continue to receive benefits on a 50/50 sharing basis from the opportunities for OSS margins. Mr. Pascarella explained that the Company's proposal results in no downside risk to the customer to the extent that the customer will never receive less than 50% of the total OSS margins, while the Company retains 100% of the downside risk. He explained that under the Company's proposal, the Company's financial health is protected from the potential material earnings swings that are an inherent risk in the volatile and rapidly changing environment. Mr. Krawec explained equal and balanced sharing of the OSS margins provides the Company with an incentive mechanism to optimize the margins in a manner that will benefit I&M customers and provide a reasonable reward to the Company as well.

Mr. Chodak and Mr. Pascarella explained that the current OSS Margin "sharing" mechanism does not effectively balance the attendant risks and rewards between the customer and the Company. Mr. Chodak explained that the actual experience under the current framework has resulted in customers receiving over $109 million in benefits and I&M incurring a loss of nearly $120,000. He stated that in today's market and economic conditions, this effectively results in I&M and AEP receiving none of the reward despite having created all of the value.

As explained by Mr. Pascarella, the competitive wholesale environment for OSS optimization has undergone significant changes since the time of I&M's last rate case. The economic recession which began in 2008, and the resulting reduction in market energy requirements, the impact of new and pending EPA regulations, and the changing commodity relationship between coal and natural gas has created significant challenges for OSS. Mr. Krawec testified that these changed market conditions have caused OSS margins to drop precipitously since I&M's test year in Cause No. 43306. He stated the amount of OSS margins for the period March 23, 2009, through June 30, 2011, and the projection through December 31, 2011, shows that the treatment of OSS margins established in Cause No. 43306 has not and will not result in the fair sharing of OSS margins or result in a reasonable balancing of the interests of both the customers and the Company.

Mr. Pascarella explained that the Commercial Operations business unit is currently part of AEPSC and performs OSS optimization activities on behalf of I&M and other AEP companies. That structure was established based on the symbiotic relationship between the functions necessary to serve native load customers and the non-traditional opportunities available in the wholesale markets. OSS margins are derived from traditional and non-traditional activities and include both physical and financial trading. The non-traditional activities include the company's participation in competitive energy auctions outside of AEP's service territory through PJM Interconnection and the Midwest Independent System Operator ("MISO"), the use of financial energy trading instruments, and active hedging. Mr. Pascarella testified that many of the mWh involved in AEPSC's trading transactions are never physically delivered, but are simply trades either buying or selling, in the wholesale electric market. He stated that these may include physical transactions that are "booked out", as well as purely financial transactions that do not contemplate physical flow. A "booked out" transaction occurs when AEPSC has a purchase and a sale of the same quantity for the same specific delivery period at the same specific delivery point. The offsetting sale and purchase transactions are financially settled rather than physically delivered resulting in "booked out" transactions. Mr. Pascarella explained that over the past few years, AEP's physical generation allocated to OSS is typically only 35% to 40% of the total volume of OSS for any given year. The remaining 60% to 65% of sales volume is derived from "non-traditional" sales.

Mr. Krawec explained that per the Commission's Order in Cause No. 43306, I&M's current rates and charges for retail electric service reflect OSS margins in both basic rates and through a rate adjustment mechanism. More specifically, the revenue requirement used to establish I&M current basic rates for retail service includes a credit of $37.5 million of OSS margins allocated to the Indiana retail jurisdiction. In other words, I&M's cost of providing retail electric service in Indiana was reduced by $37.5 million of anticipated margins from AEP's wholesale market operations. He stated that in Cause No. 43306, the OSS Margin Sharing Rider was also approved. He explained that the OSS Margin Sharing Rider tracks OSS margins above the $37.5 million reflected in basic rates and shares any such margins 50% to customers and 50% to the Company. The OSS Margin Sharing Rider factors are established annually based upon a projected level of I&M OSS margins and includes a reconciliation of actual OSS margins realized and actual rider revenues for a reconciliation period. Importantly, as currently designed, there is no adjustment to basic rates or to the rider, if actual jurisdictional OSS margins fall below the $37.5 million annual threshold. This means that I&M's current basic rates were established using a revenue requirement that depends on the wholesale market to cover $37.5 million of the cost I&M incurs to provide retail electric service.

Mr. Krawec presented a Table that showed the sharing of OSS margins for the period March 23, 2009, through December 31, 2011, under the sharing mechanism established in Cause No. 43306. During the February hearing, Mr. Krawec explained that over the identified period I&M's jurisdictional OSS margins were $109,128,889. Customers received the benefit of

$109,248,407. Mr. Krawec explained on cross examination that the Company has generated approximately $120,000 less in off-system sales than what I&M has credited to the customer.

Mr. Krawec clarified that the factors reflected in the OSS Margin Rider would continue to be established annually based upon a projected level of I&M OSS margins and would include a reconciliation of actual OSS margins and corresponding rider credits applied to customer bills during the reconciliation period. He added that as new basic rates and charges would be implemented following a Commission order in this Cause, I&M would revise its OSS Sharing Margin Rider. He said the modification would reflect the 50/50 sharing of all of the jurisdictional OSS margins forecasted in the most recent OSS Margin Sharing Rider proceeding approved by the Commission prior to the filing of the revised Rider. Thereafter, in the OSS Margin Sharing Rider Reconciliation, the reconciliation would be prorated to reflect the methodology established in Cause No. 43306 and the new methodology, with any over/under recovery of OSS Margin Sharing Rider amounts being included as an adjustment to the new factors in that reconciliation proceeding. Mr. Krawec added that I&M proposes to make a compliance filing reflecting an adjustment that would result in a $14 million credit to customers under the proposed OSS rider, based upon the recently filed forecast in Cause No. 43775 OSS-2, dated August 26, 2011.

(b) <u>OUCC Case-in-Chief.</u> Mr. Wes R. Blakley, Senior Utility Analyst in the OUCC's Electric Division, did not agree that there is a need to change the design of Petitioner's OSS Margin Sharing Rider. He explained that changes in rules and regulations, the economy, consumption or demand, and technological advancements are always possible and may or may not affect wholesale electricity markets. He presented historical and projected data in support of his position that I&M still consistently receives a significant amount of OSS margins. According to Mr. Blakley, the data does not support I&M's assertion that forecasted OSS margins are significantly less than the $37.5 million currently embedded in I&M's basic rates. Mr. Blakley recommended embedding an OSS margin credit amount of $32.9 million in base rates (calculated based on I&M's smallest Indiana Jurisdictional OSS margins amount achieved over the past five years (2007 through 2011)) and, consistent with Petitioner's current OSS margin sharing mechanism, a 50/50 sharing of OSS margins above his recommended base rate amount. Based on Mr. Blakley's recommendation, Mr. Eckert increased operating revenues by $50,477,473 (total company) or $32,908,567 (Indiana Jurisdictional). Dr. Emma H. Nicholson, Economist at Exeter Associates, Inc., testified that if the Commission accepts Mr. Blakley's recommendation, it should direct I&M to allocate the benefits of the OSS margins within the cost of service study the same way that it allocates the costs of production plants in the study.

(c) <u>Industrial Group Case-in-Chief.</u> James R. Dauphinais, a Principal of Brubaker & Associates, Inc., recommended the Commission require I&M to retain $37.5 million in annual OSS margins in its base rates and continue sharing OSS margins above $37.5 million with customers on a 50/50 basis through its OSS Rider. Mr. Dauphinais's recommendation would reduce I&M's base rate revenue requirement by $37.5 million. Mr. Dauphinais acknowledged that I&M's Indiana-jurisdictional OSS margins have fallen from an annual level of approximately $96.0 million in Cause No. 43306 to an average annual level of $40.6 million for the period of July 1, 2009, through June 30, 2011. He noted I&M is also forecasting Indiana-jurisdictional annual OSS margins will continue to fall from January 1, 2012, through December 31, 2012. Mr. Dauphinais testified that these lower levels of OSS margins do not, however, justify dropping the OSS margins included in base rates to zero. He stated that the fall in OSS margins from approximately $96.0 million annually to an average level of $40.6 million has not resulted in I&M Indiana ratepayers being allocated OSS margins through I&M's base rates and OSS Rider that are in excess of I&M's actual Indiana-jurisdictional OSS margins. He also asserted that while I&M may be forecasting lower annual OSS margins for calendar year 2012 in its Cause No. 43775 OSS-2 filing, reasonable ratemaking adjustments to test year values are not based on forecasted amounts because a forecasted value is not a known and measurable value. Mr. Dauphinais suggested that if the Commission concludes that some risk sharing of OSS margins between I&M and I&M customers should occur below $37.5 million of OSS margins, $37.5 million in OSS margins should be retained in I&M's base rates, but the OSS Rider should be modified to share OSS margin shortfalls of up to $37.5 million from this amount between I&M and I&M's retail customers on a 50/50 basis.

(d) **SDI Case-in-Chief.** Mr. Smith recommended that I&M's OSS Margin Sharing Rider provide that Indiana retail customers' share of jurisdictional OSS margins be 75% of the Company's Indiana jurisdictional OSS margins. He testified that this is the ratio I&M agreed to in a settlement in Michigan that was approved by the Michigan Public Service Commission and therefore it would be equitable to apply the same ratio to I&M's Indiana customers. However, in his Cross-Answering Testimony, Mr. Smith adopted the OUCC's recommendations regarding OSS margins sharing.

(f) **South Bend Case-in-Case.** Mr. Cearley recommended that the Commission reject I&M's proposed treatment of OSS margins. He recommended the Commission should continue with its practice of reflecting 100% of test year OSS margins in base rates, which would reduce I&M's proposed revenue requirements by approximately $18.75 million. Mr. Cearley testified that with respect to OSS margins, 100% of the initial margins should accrue to ratepayers because they are the ones who pay for the assets that provide the OSS margins. He stated that I&M has not established that it needs to increase its share in OSS margin benefits and that I&M's evidence shows that the annual threshold of $37.5 million is about right.

(g) **I&M Rebuttal.** Mr. Chodak testified that the OUCC's and Intervenors' recommendations would not only be unfair, but would potentially harm I&M's ability to serve its customers and guarantee that I&M would not have a reasonable opportunity to earn the return authorized by the Commission in this case. He explained that over the last three and one-half years, the existing mechanism resulted in I&M taking a significant loss and customers receiving credit for more than 100% of the OSS margins actually earned. He characterized the OUCC's and Intervenors' recommendations as asymmetrical and stated that such treatment fails to recognize the value created by I&M's OSS agent, AEP Commercial Operations, and the fact that much of the OSS margins result from trading activities and not simply the sale of excess generation. Mr. Chodak also testified that the OUCC's recommended approach would treat I&M differently from other utilities that are able to share up or down from the level embedded in the revenue requirement used to establish basic rates. He explained that Mr. Dauphinais's alternative recommendation concedes that sharing should reflect amounts above and below the amount embedded in basic rates, but his proposed sharing starts from an even higher amount than recommended by the OUCC. Mr. Chodak explained that even then, there remains an imbalance between the efforts made to create value and the level of reward to the value creator. He explained that the 50/50 sharing of incremental changes in OSS margins, even when it is applied above and below the amount embedded in basic rates, does not actually result in a 50/50 sharing arrangement.

Mr. Krawec provided rebuttal testimony to show that the OUCC and Industrial Group's proposals regarding OSS margin sharing do not fairly recognize the impact of the earnings test imposed in the FAC proceedings. He explained that the Settlement Agreement approved in Cause No. 43306 provided that I&M's share of OSS margins and net positive financial transmission rights ("FTR") revenues under the OSS margins sharing mechanism are excluded from the earnings test in determining I&M's compliance with the provisions of IC 8-1-2-42(d)(3) and IC 8-1-2-42.3. He stated this approach recognizes that I&M should not lose its share of OSS margins through the application of the earnings test in the FAC proceedings and thus gives effect to the sharing and balancing of risk and reward. He noted that the testimony in support of the settlement agreement approved in Cause No. 43306 indicated that the provision regarding the earnings test is reasonable because the OSS margin sharing mechanism agreed to there differs from the sharing mechanism used by other Indiana utilities in that it applies only to margins above the amount embedded in the revenue requirement. He testified that the one-way sharing proposals offered by the OUCC and Industrial Group are unreasonable because these proposals, if adopted, would have the effect of clawing back I&M's share of the OSS margins via the operation of the earnings test absent the extension of the above-referenced exclusion established in Cause No. 43306.

Kevin T. Brady, Vice President – Commercial Operations for AEPSC, testified that the OSS margin sharing proposals offered by these other parties would effectively eliminate any meaningful opportunity for the Company to share in the OSS margins it creates and that the OUCC's and Intervenors' OSS margin sharing proposals fail to account for the differences between I&M's OSS margins and those of the other Indiana utilities. Mr. Brady criticized Mr. Blakley's reliance on the past five years of historic performance, stating that the wholesale market has changed dramatically over that time and past results are not an indicator of future performance. He explained that the wholesale market in general is volatile and shale gas, environmental regulations, and a dismal economy have greatly affected I&M's expectation for OSS margins. He testified that the OUCC's recommendation is inconsistent with even the existing sharing mechanism because, if the OUCC truly believes I&M's going forward OSS margins will be $32.9 million, it is in essence seeking 100% of that amount by locking it into basic rates. Similarly, Mr. Brady stated, the Industrial Group's recommendation seems to be an attempt to capture at least 100% of the OSS margins and an abandonment of the sharing concept developed in the last case and recognized as reasonable and appropriate by the Commission in past cases. He noted the Industrial Group's position also fails to recognize the Commission's findings in other cases where the OSS margins sharing issue was litigated in which the Commission approved sharing above and below the amount embedded in basic rates.

Mr. Brady stated that the OUCC's proposal would penalize I&M for its success in utilizing trading activities to optimize OSS margins. He showed that when the trading activities are removed, I&M's 2009 OSS margin level (which the OUCC suggested using to set the base rate credit) drops to $11.2 million and setting the credit at $32.9 million effectively inflates the size of the credit going forward because I&M successfully produced significant OSS margins through trading activities. Mr. Brady testified that if the Commission determines that the lowest level of margins over the last five years should be embedded as a credit in rates, the amount of that credit should be $11.2 million, not the $32.9 million proposed by the OUCC.

(h) **Commission Discussion and Findings.** The Commission approved the current OSS margin sharing mechanism, which represents a bargain between I&M and its customers to share in the risks and rewards of Petitioner's efforts to maximize OSS margins. In light of the evidence in this case that reflects a downward trend in OSS margins as market dynamics have evolved, we find that an adjustment to the OSS margin sharing mechanism is appropriate.

In Cause No. 43306, Petitioner's Indiana-jurisdictional annual OSS margins were $96.0 million, and the Commission imbedded $37.5 million of OSS margins per year into Petitioner's base rates. The mechanism provided for sharing of any margins in excess of $37.5 million on a 50/50 basis between ratepayers and Petitioner. The evidence shows that from 2007 through 2011, I&M achieved the following OSS margins:

Year	*OSS Margins Realized by I&M*
2007	$89.6 million
2008	$79.0 million
2009	$32.9 million
2010	$41.4 million
2011	$42.3 million

I&M's OSS margins for the test year ended March 31, 2011, were $43.5 million. OSS margins for the pro forma period ended March 31, 2012, were $36.7 million. I&M projects that its OSS margins in 2012 and 2013 will be at or below the levels seen from 2009 – 2011.

The OUCC acknowledged that based on the historical actual OSS margins achieved by I&M between 2007 and 2012, it is appropriate to adjust the amount of OSS margins included in base rates and recommended use of the smallest annual margin achieved by I&M during the past five years or $32.9 million. I&M proposed that no OSS margins be included in base rates and that all OSS margins should be shared 50/50. We agree with the OUCC that base rates should reflect a representative amount of OSS margins to recognize the contribution that ratepayers have already made to the capital and operating expense costs associated with off-system sales of excess generation.

I&M presented evidence that it generates a percentage of its OSS margins through non-traditional means that are unconnected to asset optimization or the sale of excess power. In Mr. Busby's rebuttal testimony, I&M presented a table depicting the division of trading margins and margins excluding trading for the years 2009 through 2011. The evidence shows that the Cook Unit 1 nuclear power plant was off-line for a significant portion of 2009. Because of this, we find that the 2009 OSS trading margins are not sufficiently representative of I&M's prospective OSS margins.

Based on the evidence, the average of Petitioner's OSS margins excluding trading for 2010 and 2011 is $26.9 million. We find that it is reasonable to exclude the OSS trading margins from the amount to be imbedded in base rates because they are primarily derived from commercial transactions that do not inherently flow from generation asset optimization. Therefore, we conclude that Petitioner shall imbed $26.9 million in its base rates. This imbedded amount recognizes the contribution that ratepayers have already made toward the plant and personnel expenses required for Petitioner to conduct its traditional OSS sales. Further, because the costs of the assets being optimized are allocated on a demand basis, we direct I&M to allocate these revenues to the various rate classes based on the production demand allocation factors approved herein. In addition, we agree with Petitioner that sharing only the amount of sales in excess of the imbedded amount and not any shortfalls does not fairly align the risk and reward of OSS sales between the Company and ratepayers. Accordingly, we modify the OSS margin sharing mechanism as follows: Petitioner shall continue to share the amount of OSS margins (both trading margins and margins excluding trading) above the $26.9 million imbedded amount on a 50/50 basis with ratepayers. And Petitioner shall also be authorized to share any amount of OSS sales shortfall on a 50/50 basis with ratepayers down to $0. We find that the sharing of OSS margins below the amount imbedded in base rates reduces the risk to the Company of earnings erosion should reduced OSS margins occur.

(2) AEP Pool Capacity Settlements.

(a) I&M Case-in-Chief. The AEP Interconnection Agreement ("Agreement") requires each member to provide adequate generating facilities (or resources) to meet its firm load requirement. The Agreement allocates the AEP Power Pool capacity costs on the basis of each member's highest non-coincident peak ("NCP") in the preceding twelve months. The Member Load Ratio ("MLR") is the ratio of a member's highest NCP in relationship to the total of all members' highest NCP. The Agreement provides a capacity settlement that equalizes responsibility for installed capacity. The capacity settlement equalizes reserve margins by assigning responsibility to each member for its MLR share of the AEP System capacity. To the extent that a member's capacity is less than its AEP System responsibility, such deficit company is required to make up its shortfall by paying a capacity charge to the surplus companies, based on the embedded cost of capacity of the surplus companies.

Jennifer S. McLravy, AEPSC Director - Financial Forecasting, explained how the capacity equalization settlement is calculated under the AEP Interconnection Agreement. Ms. McLravy also explained how the surplus members of the Pool are reimbursed by the deficit members and how deficit members' capacity settlement charges are calculated.

In her direct testimony, Ms. McLravy sponsored an adjustment of test-year operating revenues to reflect the annualization of the pool capacity settlement using: (1) a normalized MLR; (2) adjusted levels of member capacity; and (3) adjusted capacity equalization rates. She calculated the normalized MLR using an average of monthly MLRs for April 2011 through March 2012. She explained that because the monthly MLR is calculated based on the peaks from the preceding twelve months, the April 2011 through March 2012 MLR reflects two separate periods of peaks: (1) actual peaks during the 12 month test year; and (2) forecast peaks during the 12-month period following the test year. She explained that the peaks in the test year (or actual period) were appropriately normalized and are consistent with the forecasted peaks in the adjustment period which are already normalized. She explained that the normalization was performed using statistical techniques to simulate adjusted peak data which effectively removes abnormalities, random events and weather impact.

Ms. McLravy's calculation showed I&M's normalized MLR is 0.19562. She explained that the normalized MLR is higher than I&M's average test year MLR of 0.19216 reflecting the normalized peaks during the test year and the normal weather and continued effect of the varying pace of economic recovery across the eastern companies of the AEP System during the twelve months following the end of the test year.

She explained that her calculation of the Pool capacity settlement adjustment annualized the end of the test year Pool capacity but made no other changes. Ms. McLravy explained that she updated the equalization rate reflected in her adjustment to include updated changes in investment cost and expected fixed operating costs.

Ms. McLravy identified three events that changed the level of I&M capacity settlement receipts: (1) the retirement of Ohio Power Company's ("OPCo") Sporn Unit 5 in September 2011; (2) the merger of Columbus Southern Power ("CSP") into OPCo on December 31, 2011; and (3) the completion of the Dresden Gas Plant as an addition to Appalachian Power Company ("APCo") capacity that occurred January 31, 2012. Ms. McLravy explained that even though I&M's capacity remained the same, the fact that the capacity changed for other members of the Pool changes whether I&M is a surplus or deficit member of the Pool and this in turn affects the capacity settlement receipts that I&M receives from or pays to the Pool. She explained that because of these three events along with normalized peaks, I&M's capacity settlement receipts from the Pool have decreased from $60.7 to $38.5 million.

She agreed with Mr. Chodak that because of the changing nature of these events, the use of a Pool Capacity Tracker might better capture the Pool Capacity Settlement for ratemaking purposes. She added that such a mechanism would provide protection for customers as well as the Company, from the potential changes identified above as well as other events that may change the level of capacity settlement receipts from the representative level reflected in her testimony.

(b) **<u>OUCC Case-in-Chief.</u>** Mr. Eckert recommended the Commission reject Petitioner's capacity equalization settlement adjustment because, he contends, Petitioner did not provide enough information to support the adjustment. He testified that I&M had not identified any specific weather events or weather trends that would support normalization of the test year MLR. He also stated that I&M provided no specific reasons why it needed to adjust its capacity equalization rates.

(c) **<u>Fort Wayne Case-in-Chief.</u>** Kerry A. Heid, a rate consultant, recommended the Commission disallow the pool capacity settlement adjustment in its entirety and utilize the test year amount. He opined that the proposed operating revenue adjustment is not fixed, known and measurable because it was based solely on estimates for which he states there is complete lack of support.

(d) **I&M Rebuttal.** Ms. McLravy responded that the recommendations of Fort Wayne and OUCC with respect to the capacity settlement revenue adjustment would reflect a capacity credit that is too high and would deny I&M a reasonable opportunity to earn the return authorized in this case. She stated that I&M's proposed adjustment is reasonable and that I&M is willing to periodically adjust rates to ensure that customer rates always reflect the actual amount of the credit/charge. She testified that the test year and adjustment period results are known and that the twelve months ended March 2012 actual net capacity settlement receipts/payments of $30.8 million are much lower than the test year receipts of $60.7 million. She explained that I&M included $38.5 million on a Total Company basis as a credit in its cost of service, which lowers its revenue requirement used to set rates. Ms. McLravy explained that since the end of the test year, I&M's capacity credits from the AEP Pool have dropped substantially due to changes in the capacity in the AEP Pool. She explained that as of the end of the adjustment period I&M was making capacity payments to the Pool and this would continue until such time as new peaks are set and rolled into the calculation. Ms. McLravy added that even after that happens, I&M will not return to the level of capacity credits received during the test year. She testified that, contrary to the recommendations of Mr. Heid and Mr. Eckert, historic test year capacity payments or credits are not representative of future payments or credits. Instead, rates should be set using the fixed, known and measurable adjustment period capacity payments or credits.

In response to the criticism of her normalized MLR, Ms. McLravy also presented an alternative approach that would set rates based on actual results. She explained it would be a simple matter to periodically adjust I&M's rates to match the projected credits received or payments made with actual levels. According to Ms. McLravy, a periodic rate adjustment mechanism could set an initial level based on expected levels and then reconcile that amount to actual results once they are known. She testified that a periodic adjustment mechanism would insure that customers either receive every dollar I&M receives from the capacity settlement or pay only what I&M pays when in a capacity deficit position taking, the debate out of establishing the proper level to include for ratemaking purposes for such a volatile item.

I&M proposes that the initial tracker amount should reflect Ms. McLravy's adjusted test year expense. Mr. Krawec explained that the Capacity Tracker factors would be established annually based upon a projection of capacity payments/receipts to be tracked and will include a reconciliation of actual capacity payments/receipts for the prior year. If the Commission approves I&M's tracking proposal, Mr. Krawec stated I&M will file compliance tariffs reflecting this initial tracker recovery. Within nine months after the implementation of the initial capacity tracker, I&M would file a petition and supporting testimony and exhibits for approval to implement the first annual adjustment to the Capacity Tracker. Mr. Krawec explained that in the first annual proceeding, the initial factor would be reconciled and a new factor would be proposed based upon a forecast of capacity payments/receipts during the period the factor will be in effect adjusted for the amount of the reconciliation.

(e) **Commission Discussion and Findings.** I&M's capacity payments and receipts are governed by the formulas established in the FERC-approved AEP Interconnection Agreement. The evidence establishes that the test-year level of capacity settlement receipts is not representative of I&M's ongoing capacity settlements due primarily to actual changes that have occurred in the amount of capacity owned by other members of the AEP

Pool. The actual results for the twelve-month period following the test year support I&M's contention that test-year levels are not representative of current and ongoing future costs. The capacity settlements received by I&M in the post-test-year twelve-month period declined by approximately $30 million. Ms. McLravy identified three key changes driving the reduction in the capacity settlements: (1) the retirement of OPCo's Sporn Unit 5; (2) the merger of CSP into OPCo; and (3) the completion of the Dresden Gas Plant as an addition to APCo capacity. Based on this evidence, we find that the test year results for I&M's capacity settlement are not representative of current and future experience in light of the changes identified by Ms. McLravy.

In order to address the variability in the capacity settlement payments, we adopt I&M's proposal to periodically adjust I&M's rates to match the projected credits received or payments made with actual levels pursuant to Ind. Code § 8-1-2-42(a). We find such an adjustment mechanism appropriate in light of the materiality of the settlement capacity receipts and payments and the significant and unpredictable changes in the capacity settlements. The level of revenue recognized by I&M fell by nearly 50% during the twelve months following the test year. The initial level of revenues for the capacity settlement should be set at $38.5 million. This reflects the actual settlement receipts/payments of $30.8 million for the twelve months ended March 2012 and Ms. McLravy's normalization of this amount. The Capacity Tracker factors shall be established annually based upon a projection of capacity payments/receipts to be tracked and will include a reconciliation of actual capacity payments/receipts for the prior year as proposed by Mr. Krawec. I&M shall file compliance tariffs reflecting this initial tracker recovery. Within nine months after the implementation of the initial capacity tracker, I&M shall file a petition and supporting testimony and exhibits for approval to implement the first annual adjustment to the Capacity Tracker. As proposed by Mr. Krawec, the initial factor will be reconciled and a new factor will be proposed based upon a forecast of capacity payments/receipts during the period that the factor will be in effect adjusted for the amount of the reconciliation.

(3) <u>Reclassification of Revenues.</u>

(a) <u>OUCC Case-in-Chief.</u> Ms. Stull recommended reclassification of certain below-the-line revenues that I&M received during the test year for its share of royalty payments from Westinghouse Electric Company. The royalty payments relate to a first-of-a-kind engineering sub-contract awarded to Westinghouse in 1992 for a project coordinated by the Advanced Reactor Corporation ("ARC") under a Department of Energy ("DOE") Cooperative Agreement. Ms. Stull explained that funding to ARC to undertake this activity was provided by the Electric Power Research Institute ("EPRI"), the DOE, and supporting members of ARC. Ms. Stull proposed an adjustment to increase test year "Other Revenues" in the amount of $275,717 and explained that her proposed reclassification of these below-the-line revenues is reasonable because Petitioner included 100% of its EPRI costs in its proposed revenue requirement, as it has done in past cases. Ms. Stull opined that either both EPRI membership costs and associated revenues should be recorded above-the-line or both should be recorded below-the-line.

(b) <u>I&M Rebuttal.</u> Mr. Brubaker recommended the Commission reject Ms. Stull's proposal and make no adjustment. He disagreed with Ms. Stull's conclusion that I&M's customers are entitled to these below-the-line revenues. He explained that the royalty revenues recorded below-the-line have no relationship to I&M's EPRI dues. Rather, he explained, I&M is entitled to the royalties because it was one of the supporting members of the ARC that elected in 1992 to invest in ARC along with the EPRI and DOE. Mr. Brubaker stated EPRI's investment in ARC was not on behalf of all EPRI dues-paying members and I&M was not a member of EPRI in 1992, when the Company became a supporting member of ARC. Mr. Brubaker's rebuttal testimony included as an exhibit a communication from EPRI documenting that the work associated with the royalties was not part of the annual EPRI membership dues but were instead separate payments made to ARC for the project. Mr. Brubaker also testified that I&M's membership in EPRI began after the Commission granted approval in its Order dated November 12, 1993 in Cause No. 39314. Mr. Brubaker stated that the cost of I&M's investment as an ARC supporting member was never part of a revenue requirement used to establish I&M's basic rates.

(c) Commission Discussion and Findings. Based on the evidence, we reject the OUCC's proposed reclassification of the royalty revenues associated with I&M's investment as a supporting member of ARC. Mr. Brubaker's rebuttal testimony shows that I&M's customers did not fund the costs associated with the royalties. We are persuaded by Mr. Brubaker's rebuttal testimony that the EPRI dues included in the cost of service are unrelated to the royalties recorded below-the-line. We also decline to reclassify these revenues based on the evidence that they were properly recorded below-the-line in accordance with the FERC Uniform System of Accounts.

C. Disputed O&M Expense Adjustments.

(1) Carbon Capture and Storage Research and Development Costs.

(a) I&M Case-in-Chief. Mr. Chodak discussed the research and development project undertaken by the Company as part of the AEP System, to provide for the use of coal at an increased level relative to what it would be otherwise under regulation that constrains carbon emissions. He explained that this research includes evaluating a technology to remove carbon dioxide (CO_2) from flue gas and safely store it underground. He stated that this research involves a test project at the Mountaineer Plant owned by I&M affiliate, APCo.

Mr. Chodak explained that using the results of an initial test effort, AEP is conducting a Carbon Capture and Storage ("CCS") Front End Engineering Design ("FEED") Study. He stated that the CCS FEED Study is essential research into the CCS process that is directly transferable to I&M's Rockport Plant because it is of the same design as the Mountaineer Plant. Mr. Chodak stated that the FEED Study positions the Rockport Plant to continue to provide low cost generation to I&M's Indiana customers. Mr. Chodak added that it also will provide for the increased use of Indiana coal in the event that CCS is necessary to comply with carbon emission regulations.

Mr. Chodak explained that while I&M and its customers will receive the benefit of the entire FEED Study, the cost to I&M is only a fraction of the total cost because this research and development effort is being undertaken by the AEP System. He stated that I&M's share of the costs of the FEED Study is based on its ratio of coal-fired capacity that may use the CCS technology, which ratio is 11.5%, or $1.6 million (Total Company). As supported by Mr. Krawec, the proposed revenue requirement includes $520,798 to reflect an amortization of the

Indiana retail jurisdictional share of this cost over a two-year period. Mr. Chodak believes it is reasonable to include this amount in I&M's revenue requirement because the CCS FEED Study is beneficial to I&M's customers, is a proactive step taken to reasonably anticipate expected environmental regulations, and will allow I&M to continue to depend on the coal-fired Rockport Plant for electric generation with reduced environmental impact.

(b) **OUCC Case-in-Chief.** Cynthia M. Armstrong, Senior Utility Analyst in the OUCC Electric Division, recommended removal of I&M's adjustment for the CCS FEED Study costs from the revenue requirement calculation because she believes the CCS FEED Study costs are an unreasonable expense to recover from I&M's ratepayers.

In support of her recommendation, Ms. Armstrong stated that the equipment involved in the study is designed to operate on a plant that is not owned by I&M and is not part of I&M's rate base. Ms. Armstrong stated that I&M does not currently have plans to install CCS on the Rockport Plant. According to Ms. Armstrong, CCS FEED Studies are highly site-specific and even if the design of the capture equipment at Mountaineer were transferable for the possible deployment of carbon capture equipment on Rockport, the Rockport Plant would still have to conduct another study to determine the geological sequestration injection sites for carbon dioxide in the Rockport area and the transportation system to such a site. She stated that if and when I&M conducts a FEED study at Rockport, then it may be reasonable to seek recovery of costs from I&M's retail ratepayers.

Ms. Armstrong expressed concern that I&M did not inform the Commission of its intent to conduct the CCS FEED Study outside of Indiana and pass the study's cost on to I&M retail customers. She asserted that the Commission and other interested parties have had no opportunity to review the study in depth and the Commission has not found the costs are reasonable for inclusion in I&M's Indiana rates through another proceeding. Ms. Armstrong also stated that the local job and tax benefits realized in West Virginia as a result of the study have not been shown to extend to the Indiana retail jurisdiction and therefore costs from the project should not be passed on to Indiana retail ratepayers. She suggested that the study places APCo at an advantage over other AEP System coal units with respect to future construction of new coal-fired units capable of complying with the EPA's proposed Greenhouse Gas ("GHG") New Source Performance Standards ("NSPS") and Greenhouse Gas Tailoring Rule because the results of the initial studies at the Mountaineer site indicate that it has suitable sites nearby for the geological sequestration of CO_2. She indicated this presents Mountaineer with an advantage over other AEP System coal units that will still have to conduct studies to determine whether there are similarly suitable geological sequestration sites. Ms. Armstrong suggested that Mountaineer also may have an advantage with respect to GHG Prevention of Significant Deterioration permitting under the proposed GHG Tailoring Rule, because if the facility makes any major modifications which would increase the site's GHG emissions by more than 75,000 tons CO_2, then it will already have CCS installed to treat and offset those emissions.

Finally, Ms. Armstrong expressed concern that if the Commission allows I&M to include the APCo project in rates and the project is successful, I&M's ratepayers would have paid for a project without having access to the benefit of any carbon credits or allowances that may arise from the project. Ms. Armstrong recommended that AEPSC be required to allocate a portion of any future CO_2 allowance revenues to I&M to pass back to its ratepayers.

As a result of Ms. Armstrong's recommendations, Mr. Eckert adjusted the Company's O&M expense to remove the proposed adjustment of $805,500 ("Total Company"). Mr. Eckert also disagreed with Petitioner's proposed two-year amortization period for the FEED Study adjustment. If the Commission were to accept I&M's adjustment, Mr. Eckert recommended amortizing the expense over the expected life of the rates.

(c) **Industrial Group Case-in-Chief.** James T. Selecky, Managing Principal of Brubaker & Associates, Inc., also opposed the inclusion of the CCS FEED Study costs in I&M's revenue requirement based on his assumption that much of the study will be specifically geared toward the Mountaineer plant since it involves a test project at that plant. He stated that he is unaware of any plans to install any type of CCS facility at the Rockport Plant. Further, he testified that it appears I&M is seeking cost recovery simply because of a ruling of the West Virginia Public Service Commission denying APCo's requested recovery of the Mountaineer CCS costs. He opined that because I&M did not seek prior approval from this Commission to participate in the FEED study, I&M's ratepayers should not be expected to pay for the costs of that study. Mr. Selecky recommended a reduction to total Company O&M expense of $805,500.

(d) **SDI Case-in-Chief.** Mr. Smith provided testimony opposing I&M's O&M expense adjustment for the CCS FEED Study, stating that I&M has not shown how its ratepayers have or will benefit from the study. Mr. Smith testified that a similar proposal by an AEP company was rejected by the Virginia State Corporation Commission ("VSCC"). Mr. Smith described the VSCC's decision with respect to recovery of the FEED Study costs and concluded that the same or similar factors and concerns that caused the VSCC to reject APCo's requested recovery of FEED Study costs from Virginia ratepayers would be applicable to I&M's request. Mr. Smith recommended removal of the FEED Study costs. He recommended that I&M's request for a regulatory asset and amortization of FEED Study costs over two years also be rejected.

(e) **I&M Rebuttal.** Mr. Chodak responded to the OUCC's and Intervenors' recommendations to exclude CCS FEED Study costs from I&M's revenue requirement. He stated his belief that the inclusion of these costs for ratemaking purposes is expressly permitted by the governing regulatory framework as set forth in Ind. Code §8-1-1-2-6.1(c)(1) and 170 IAC 4-6-17. He cited the Commission's January 7, 2009 Order in Cause No. 43114 IGCC 1 ("Duke IGCC1 Order"), which permitted FEED Study costs to be recognized for ratemaking purposes, noting that such cost recovery is expressly addressed by the governing statute and rule. He explained that the CCS FEED Study research and development ("R&D") activities are directed toward minimizing the environmental impact of coal and costs incurred by I&M in connection with the study are a necessary and appropriate cost of providing utility service. He stated that it would be premature to plan to install CCS on the Rockport Plant before the R&D phase is completed and the product is commercially available. He reiterated that the research into the CCS process is directly transferable to I&M's Rockport Plant because it is of the same design as the Mountaineer Plant. Mr. Chodak testified that the FEED Study positions the Rockport Plant to continue to provide low cost generation to I&M's Indiana customers and will provide for the increased use of Indiana coal in the event that CCS is necessary to comply with carbon emission regulations.

Mr. Chodak explained that Ms. Armstrong's recommendation that I&M wait to seek recovery of costs until a FEED study is conducted at the Rockport Plant would result in an inefficient duplication of efforts and higher costs for I&M customers. He reiterated that I&M and its customers will receive the benefit of the entire FEED Study, while incurring only a small fraction of the total cost because this R&D effort is being undertaken by the AEP System.

Mr. Chodak disagreed with Ms. Armstrong that Commission preapproval is required in order to recognize the R&D expense for ratemaking purposes. He noted that I&M provided a copy of the CCS FEED Study to the OUCC and other intervenors on November 7, 2011 in response to a formal discovery request by the OUCC, which was then attached to Ms. Armstrong's testimony as Confidential OUCC Attachment CMA-2.

Mr. Chodak testified that the R&D is a necessary prerequisite to the additional work described by Ms. Armstrong to determine the geological sequestration injections for carbon dioxide in the Rockport area and to identify the transportation system to such a site.

Mr. Chodak opined that coal may reasonably be expected to be a dominant energy source for the country for decades to come because of its abundance and versatility. He stated that while some may oppose the use of coal as an energy source, it simply is not cost effective or even possible to transition away from coal in the short run. He noted that the EPA has already issued a draft GHG rule for new sources and plans to follow-up with a GHG standard for existing plants in 2013.

(f) <u>Commission Discussion and Findings.</u> I&M has requested that the Commission approve recovery of $1.6 million, which represents I&M's total company share of the cost apportioned to it by its parent, AEP, to conduct a Carbon Capture and Sequestration FEED study at the Mountaineer Plant owned by APCo. I&M contends that recovery of this cost is justified pursuant to Ind. Code § 8-1-2-6.1(c)(1) and 170 IAC 4-6-17. The OUCC, Industrial Group, and SDI all opposed recovery of the costs.

Although I&M contends that the results of the FEED study are "directly transferable" to its Rockport facility, the evidence does not support that conclusion. In fact, the evidence in the record shows that I&M has no intention of adding CCS technology to the Rockport facility at the present time. We are unwilling to authorize the recovery of FEED Study expenses that were undertaken without prior submission to the Commission for approval. In the absence of our prior review of the FEED study, we cannot pass judgment on the reasonableness or necessity of the study or costs. Under such circumstances, we are not inclined to impose upon Indiana ratepayers financial responsibility for a project which we have never had an opportunity to consider or authorize, and which is likely to be of limited value to those ratepayers. Accordingly, we deny I&M's request to include recovery of the costs associated with the FEED study in rates and reduce I&M's proposed revenue request in this proceeding by Indiana's jurisdictional share of the $520,798 assigned to the Company by AEP.

(2) <u>Dry Cask Canisters, including Storage.</u>

(a) <u>I&M Case-in-Chief.</u> Mr. Carlson explained the Dry Cask Storage process and major components and testified that the Dry Cask Storage Project provides spent nuclear fuel dry storage capacity at the Cook Plant at an Independent Spent Fuel Storage Installation ("ISFSI"). He also explained that if additional fuel storage space were not made available, the Spent Fuel Pool ("SFP") would become full and the ability to offload spent fuel from the reactor to the SFP would be lost. If the spent fuel cannot be removed from the reactor due to a loss of space in the SFP, new fuel cannot be loaded into the reactor and would require a shutdown of both units in approximately 2015. He testified that, by investing in the Dry Cask Storage Project, operations are able to be extended indefinitely, at least from a nuclear fuel perspective. Mr. Carlson testified that the first loading campaign is scheduled to occur in 2012 during which 16 casks will be loaded with a total of 512 fuel assemblies (32 per cask) and 4 placed at the ISFSI. He also explained that, due to the complexity of dry cask storage, the project began 5 years in advance of this loading campaign.

Mr. Carlson testified that the dry cask work included in the Company's Rate Base Adjustment No. 4 shown on Petitioner's Exhibit A-6 is comprised of many activities, including design and construction of the ISFSI; multiple engineering analyses and product reviews; labor and field services; construction and project management; and procurement of the dry cask transportation vehicle. He explained that this work was performed to ensure uninterrupted operation and to allow customers to retain access to low cost, essentially emission-free, and reliable electricity.

Mr. Brubaker adjusted test year O&M expense to increase I&M's operating expenses by \$259,132 to amortize the cost of dry cask canisters. Mr. Carlson explained that the initial dry cask canister cost is \$1,166,095 and is based on the number of spent nuclear fuel assemblies needing to be placed into dry cask storage as new fuel assemblies for refueling outages arrive at Cook. He stated that the amortization of the initial canister cost will take 54 months and will align with the three 18-month cycles in which nuclear fuel burns.

Mr. Carlson stated that the Cook Plant will be receiving new fuel assemblies for the Unit 1 refueling outage in Fall 2011. He also explained that this shipment of fuel will put Cook in a position of being beyond the capacity of the Spent Fuel Pool, if both cores were required to be unloaded. Mr. Brubaker explained I&M will begin expensing the cost of the canisters as fuel is consumed over the 54 month burn cycle using a cost per fuel assembly based on the cost of canisters to be used in the first haul campaign. As new fuel assemblies are loaded in the future, the calculated canister cost per fuel assembly will be amortized over each respective 54 month burn cycle. Mr. Brubaker noted that if this adjustment was not made, I&M's test year operating expenses would be understated since there is no canister expense recorded in the test year.

(b) **<u>OUCC Case-in-Chief.</u>** Mr. Michael D. Eckert recommended that \$1,775,040 in total company expense and \$1,147,655 in Indiana Jurisdictional expense be eliminated from O&M expense because these amounts reflect a one-time non-recurring expense. Mr. Eckert also recommended that the Commission deny I&M's request to include in the revenue requirement the amortized portion of the cost of the initial canister (total company - \$259,132 and Indiana jurisdictional - \$164,518) because: (1) the costs represent a one-time project and are non-recurring; and (2) I&M entered into a settlement agreement with the U.S. Department of Energy ("DOE") regarding the government's decision to abandon development of a repository at Yucca Mountain. He testified that I&M received \$14,125,864 from the DOE due to the abandonment and that the Company also has requested an additional \$20.9 million from

DOE for other expenses it has incurred.

(c) **<u>I&M Rebuttal.</u>** On rebuttal, Mr. Krawec contested Mr. Eckert's assessment that the cost of the initial dry cask canisters were a one-time project and non-recurring. He explained that the Cook Plant will shut down unless the storage of spent nuclear fuel in dry casks occurs as a regular activity (*i.e.*, loading campaigns). He further explained that as the Dry Cask Storage Project was performed to ready the plant for the loading campaigns, the dry cask canisters for the initial loading campaign were procured as part of this project and accordingly, are properly amortized as O&M expenses in accordance with FERC accounting guidelines.

Mr. Krawec explained that the initial dry cask loading campaign will occur in 2012 and that additional dry casks will be loaded with spent nuclear fuel in subsequent loading campaigns, which will occur approximately every 3 years. As he explained, this activity is and will continue to be required until a permanent storage alternative becomes available. He also testified that the Cook Plant will continue to procure dry cask canisters for these loading campaigns throughout the remaining license periods of the units, and these purchases will be properly recorded initially to Account 165, Prepayments, and costs subsequently amortized to O&M expenses. He testified that due to the continuing dry cask loading campaigns going forward, this recurring amortization expense is appropriate for inclusion in I&M's revenue requirement.

In response to Mr. Eckert's argument that the dry cask storage canister expense should be entirely removed because of the settlement with the DOE, Mr. Krawec testified that while the Company has reached agreement on certain costs related to Dry Cask Storage, and some of those payments from the DOE have included reimbursement for canister costs, I&M still has a considerable investment in canisters that has not been recovered from the DOE and I&M continues to record a monthly expense related to the cost of canisters. Mr. Krawec noted that Mr. Eckert appears to believe that the future recovery of all of I&M's current and future investment in spent fuel storage canisters from the DOE is fixed and known. Mr. Krawec testified that the fact of the matter is that there is no assurance that such recovery will occur. He also testified that, as shown on Petitioner's Rebuttal Exhibit A-R5, O&M Adjustment R32, I&M has reduced the Total Company canister cost amortization from $259,132 to $177,372 to reflect the effect of the DOE reimbursement.

Mr. Krawec responded to Mr. Eckert's proposal to eliminate $1,775,040 in total company and $1,147,665 in jurisdictional expense related to the dry cask storage project. Mr. Krawec explained that the Company's original response to OUCC DR 37-1 and 37-2 had reported this expenditure as an "O&M" cost, but as shown on Petitioner's Exhibit SMK-R2, the Company has provided a supplemental response to OUCC DR 37-1 and 37-2 indicating that there were no O&M expenses included in the test year for the dry cask storage project. He further explained that while dry cask canister costs will be amortized to O&M in the future, and they were not charged to an O&M expense account during the test year. Mr. Krawec stated that these costs were instead charged to FERC Account 165, Prepayments, which is a balance sheet account. Specifically I&M charged Account 1650022 for prepayments associated with canisters used to store Spent Nuclear Fuel ("SNF") that will be placed in dry cask storage. Amounts charged to Account 1650022 are not included in the Company's rate base or cost of service. Mr. Krawec testified that it is inappropriate to make an adjustment to eliminate $1,775,040 (Total Company) and $1,147,665 (Indiana Jurisdictional) for dry cask storage expenditures from O&M expense in the test year because these specific dry cask storage expenditures were not recorded to O&M expense in the test year.

(d) **Commission Discussion and Findings.** Based on the evidence, we find that the expenses associated with the Dry Cask Canisters and their storage are costs that I&M will incur on an ongoing basis as part of its obligation to procure dry cask canisters for loading campaigns throughout the remaining license periods of the Cook Plant units, and thus they do not constitute a one-time project or non-recurring costs. As a result, we find that I&M's calculation of dry cask canister expenses should be adopted. In making this finding, we note that the public interest in the safe storage and ultimate disposal of spent nuclear fuel requires that I&M fulfills its important obligation in an efficient and cost-effective manner. I&M has shown that it has in place an ongoing program to effectively manage the acquisition of dry cask canisters in a pro-active and measured manner so that the initial dry cask loading campaign and the additional dry casks that will be loaded with spent nuclear fuel in subsequent loading campaigns, which will occur approximately every 3 years, can take place. We find that I&M properly reflected a canister cost amortization in its O&M expense. Therefore, we reject the OUCC's proposed adjustment to eliminate $1,147,665 (Indiana Jurisdictional) from test year O&M.

(3) **NRC Fees.**

(a) **I&M Case-in-Chief.** Mr. Carlson sponsored O&M Expense Adjustment No. 33 of Petitioner's Exhibit A-5, which increased Nuclear O&M expense by $955,907 (Total Company) or $618,043 (Indiana Jurisdictional). He explained that activities at the Cook Plant are governed by NRC regulations and I&M is assessed a fee to fund the cost of NRC regulation. During the course of plant operation, Mr. Carlson testified, the NRC regulations require activities that must be implemented in response to a number of variables, including external items such as operating events at other nuclear plants, new rule making, technology enhancements, as well as internal items. He stated the increase in O&M reflects the amount for NRC-mandated fees that I&M will incur for performing such activities and is based on the amounts published in the Federal Register.

(b) **OUCC Case-in-Chief.** Mr. Eckert noted that I&M reflected NRC 2011 fiscal year hourly rate of $273 in its calculation of NRC Inspections and Reviews expense. He revised the pro forma level of NRC fees included in regulatory commission expense to incorporate the FY 2012 fee schedule published on March 15, 2012, which reflected an actual hourly rate ($274). Mr. Eckert also recalculated the pro forma annual expense for NRC annual reviews using the actual test year bills received by Petitioner from the NRC. Mr. Eckert recommended a reduction of $1,342,259 (Total Company) or $867,840 (Indiana Jurisdictional) for NRC annual fees, including inspection and review fees.

(c) **I&M Rebuttal.** Mr. Brubaker testified on rebuttal that while Mr. Eckert accurately represented the amount for NRC annual fees by using the actual amounts from invoices provided in discovery, he incorrectly used an estimate for the hourly inspection and review fees. He explained that Mr. Eckert should have summed the amounts shown on the invoices received by I&M during the twelve months following the end of the test year. Using that methodology, the total annual hourly inspection and fee amount is $1,969,141. Mr. Brubaker concluded that the $955,907 increase proposed for O&M Expense Adjustment No. 33 should now be a reduction to test year expenses in the amount of $298,868. This is a $1,254,775 (Total Company) reduction to I&M's filed case instead of a $1,342,259 (Total Company) reduction recommended by Mr. Eckert. Mr. Brubaker stated the change reflects actual amounts from April 2011 through March 2012 for the annual inspection and review fee component of the total NRC fees.

(d) Commission Discussion and Findings. Petitioner and the OUCC generally agree that NRC fee expense should be based on actual amounts from April 2011 through March 2012 for the annual inspection and review fee component of total NRC fees. We approve the corrected adjustment reflected in Petitioner's Exhibit A-R5 O&M Adjustment R33.

(4) Major Storm Expense.

(a) I&M Case-in-Chief. J. Edward Ehler, Vice President of Distribution Operations for I&M, provided evidence to support I&M's proposed adjustment to the test year to increase distribution and transmission O&M expense by approximately $2.3 million to reflect a three-year average of major storm O&M expense (using the three-year period ending March 31, 2011). Mr. Ehler testified that the average more accurately represented the normalized level of major outage restoration expenses.

Mr. Ehler testified as to the reasonableness of the storm restoration level proposed by discussing the random and unpredictable nature of storms, including the fact that storms can vary in size, significance and impact, thus creating volatility in the level of related expenses year to year. To provide perspective, Mr. Ehler explained that, during 2011, a single major storm cost approximately $1.2 million, an amount representing over half of the approximately $2.3 million adjustment. He testified that this information, coupled with the evidence showing that test year major storm damage restoration amount is significantly less than the $6.1 million average major storm cost, demonstrates the reasonableness of the proposed level.

Mr. Ehler testified that the Commission has accepted I&M's use of a three-year amortization period in a previous I&M rate case. Mr. Ehler explained that using a consistent approach for determining major storm expense for ratemaking purposes is reasonable and appropriate because it recognizes that major storms are experienced in the normal course of events. Thus, it is appropriate to include a normalized amount for setting rates.

(b) OUCC Position. Mr. Eckert agreed with the Company that it is reasonable to normalize storm-related costs. He proposed that the test year be adjusted based on the five-year average for the period April 2006 through March 2011. Mr. Eckert's proposed adjustment resulted in total normalized distribution annual storm expenses of $4,047,529 and transmission annual storm expenses of $165,598. Mr. Eckert also noted that in calculating its adjustment for transmission plant major storm expense I&M inadvertently subtracted its pro forma expense amount from its test year expense and calculated an increase to Major Storm Expenses of $210,659. He explained that I&M should have subtracted the test year expenses for the pro forma proposed expenses. The correct calculation would have resulted in a decrease to Major Storm Expense of $210,659.

Anthony A. Alvarez, Utility Analyst within the OUCC's Resource Planning and Communications Division, testified concerning customer outage duration and customer outage kilowatt-hour loss during Major Event Days ("MEDs") to support Mr. Eckert's adjustment to Major Storm Expense. He opined that this analysis supported Mr. Eckert's proposed pro forma major storm expense level.

(c) Industrial Group Position. Mr. Selecky opposed I&M's proposed increase in storm damage O&M expense of approximately $2.3 million and recommended that the Commission cap the level of storm damage O&M expense in the Company's revenue requirement at the five-year average, or $4.213 million. He testified that I&M's proposed three-year average for storm damage includes a significant storm damage cost for 2009 and should not be viewed as a representative value. Mr. Selecky also offered an alternative procedure in which the Commission would look at the last five years, remove the highest and lowest year and develop a three-year average from that data, which would result in storm damage expense of $2.225 million.

(d) SDI Case-in-Chief. Mr. Smith did not object to I&M using a multi-year period as the basis for establishing a normal level of major storm expenses. He stated that looking at data for a fluctuating expense over a multi-year period is a reasonable way to establish a normal allowance for ratemaking purposes. He indicated, however, that he was not convinced the three-year period used by I&M to calculate its adjustment is the best representation of a normal level for major storm expense for I&M. In his cross-answering testimony, Mr. Smith supported the OUCC recommendation.

(e) I&M Rebuttal. Mr. Krawec noted that I&M, the OUCC, the Industrial Group, and SDI all agree that major storm expenses should be normalized and that normalization is the proper way to account for an irregular, but not unexpected occurrence. Mr. Krawec explained that the disagreement centers on what period should be used to develop the average or normalized expense. In response to the contentions of the OUCC, Industrial Group and SDI that I&M's normalization period resulted in an abnormally high expense level and that a longer period would be more representative, Mr. Krawec explained that the very process of normalization ameliorates the impacts of an unusually high or low expense level and thus alleviates concerns that the test year expense might be an anomaly. He also explained that I&M's three-year proposal is consistent with prior practices of the Company. Mr. Krawec testified that this methodology was accepted by the Commission in Cause No. 39314 where it reduced I&M's major storm expense. He also indicated that, in I&M's last rate case, Cause No. 43306, I&M also proposed a three-year average for major storm expense, but through settlement negotiations agreed to use a five-year average to determine the agreed revenue requirement.

Mr. Krawec noted that although I&M cannot predict when severe storms will hit, they do occur and are part of I&M's ongoing operations. Mr. Krawec noted that recent experience shows that I&M has experienced an extremely destructive storm, such as I&M experienced in 2008, every three years. For example, prior to 2008, I&M experienced a January 2005 weather event in I&M's Muncie District that resulted in 87% of the District's customers losing power. In the same year, I&M's Indiana jurisdiction had over $15 million in O&M expenses related to major storms. Mr. Krawec concluded that a methodology utilizing five years or more is an inconsistent approach that is not representative of I&M's true restoration costs.

(f) <u>Commission Discussion and Findings.</u> I&M, the OUCC, Industrial Group, and SDI agree that I&M should be permitted to recover costs prudently incurred to recover from storm damage. These parties also agree that major storm damage expenses vary widely from year to year and should be normalized by using the average over some period of years. Their disagreement lies only in the appropriate period over which to average major storm damage expenses. I&M proposed using a three-year average. The other parties propose using at least a five-year average. The difference between these two proposals is significant – under I&M's proposal, the normalized level of major storm expenses would be approximately $6.2 million per year. Under the OUCC's and other parties' proposal, the normalized level of major storm expenses would be approximately $4.2 million per year. In other words, the OUCC and the other parties are proposing major storm damage expenses that are only 68% those proposed by I&M.

Major storm damage expenses present a unique problem for rate-making. We all know that major storms will occur, but nobody can predict when they will hit, how often they will hit, or what damage they will cause. Indeed, it is for these very reasons that I&M has proposed a new rate-making tool – the major storm damage reserve – which we will address separately below.

I&M asserts that its proposed three-year average is a more accurate reflection of its actual expenses caused by major storm damage than the longer five-year average proposed by the OUCC and other parties. While this might be true were we simply imbedding an amount of storm damage expense into Petitioner's rates, in light of the fact that we are approving I&M's storm damage reserve mechanism below, we find that using the 5-year average of $4.2 million provides a better base amount to start from in tracking storm damage expenses.

(5) <u>Major Storm Damage Restoration Reserve.</u>

(a) <u>I&M Case-in-Chief.</u> Mr. Krawec sponsored I&M's request to create a Major Storm Damage Restoration Reserve (the "Reserve") because O&M expenses associated with restoration efforts as a result of major storm damage are volatile in nature. Mr. Krawec testified that I&M's test year storm damage O&M expense as adjusted, is approximately $6.2 million (Indiana Jurisdictional). Effective with the implementation of new basic rates that include the proposed major-storm damage restoration reserve mechanism, I&M will calculate monthly any over-recovery or under-recovery by comparing the current month proposed major-storm damage restoration reserve revenues collected in basic rates to the current month major-storm damage restoration expenses. If the incurred O&M expense is less than the monthly amount reflected in the revenue requirement, the Company will record a regulatory liability in Account 254, Other Regulatory Liabilities, for any over-recovery related to its proposed Major Storm Damage Restoration Reserve. If the incurred O&M expense exceeds the monthly amount included in the revenue requirement, the Company will record a regulatory asset in Account 182.3, Other Regulatory Assets for any under-recovery. The cumulative regulatory liability or regulatory asset balance would be adjusted each month based on actual major storm damage O&M expense incurred versus the embedded amount.

In its next general rate case, I&M proposes to include an amortization in the cost of service developed for that case which will either reduce the cost of service for any over recovery or increase the cost of service for any under recovery at the end of the historical test period. In addition, I&M will propose an adjustment to the base level of the Indiana Major Storm Damage Restoration Reserve that reflects recent historical major storm damage levels.

Mr. Brubaker explained that generally accepted accounting principles ("GAAP") and in particular FASB ASC 980 (formerly SFAS No. 71, Accounting for the Effects of Certain Types of Regulation) requires deferral accounting when a regulatory commission requires future rates to be reduced to refund an over recovery and when a regulatory commission provides for the future recovery of incurred expenses or it is probable that a regulatory commission will provide for such future recovery of an incurred expense. Therefore, in order to record regulatory liabilities or regulatory assets and perform regulatory deferral over/under true-up accounting, it must be probable that the resultant regulatory assets or regulatory liabilities will be recovered, or returned to customers, through future regulated rates. He further explained that the probability requirement will be satisfied if the Commission's Order provides for prospective rate adjustments in basic rates, either upward or downward, to recover from customers or return to customers the deferred under-recovered regulatory asset or over-recovered regulatory liability balances, respectively. When that occurs, the regulator-created asset, or regulatory asset, must be recorded by deferring the incurred cost to be recovered in the future or the regulator-created liability, or regulatory liability, must be recorded by deferring the amount to be returned in the future.

Mr. Brubaker also testified that the FERC Uniform System of Accounts requires that regulatory assets and regulatory liabilities imposed on the utility by the ratemaking actions of regulatory agencies be included in Account 182.3, Other Regulatory Assets and Account 254, Other Regulatory Liabilities, respectively as I&M proposed.

(b) **<u>OUCC Case-in-Chief.</u>** Mr. Blakley testified that I&M is seeking special accounting treatment attached to a single expense account. He also testified that there will be nothing in rates that accumulates funds for a reserve amount to be used later for storm damage expenses. According to Mr. Blakley, the ability to create a regulatory asset for expenses that may go over a base amount creates a hedge for I&M in dealing with its major storm expense and that I&M will be protected from any storm damage expense caused by major storm events exceeding the monthly base amount of $516,667. He also testified that he does not recall seeing a request for an operating expense that included special accounting treatment that essentially guaranteed recovery of an operating expense that exceeds a base amount. According to Mr. Blakley, the potential future cost to the ratepayers of the regulatory asset is entirely open-ended and unknown. He also testified that, if this special treatment is approved, any party that seeks to challenge the future amount will have a very difficult task, which could require reviewing multiple years of monthly storm damage accounting.

Mr. Blakley testified that the treatment proposed is without regard to other expense components or return components that may change during the same period. He cited to the Commission's final order in Cause No. 43743, issued October 19, 2011, in which the Commission discussed why single issue ratemaking in the context of major storm expense is inappropriate. He also testified that the operation of a utility involves risk and such risks are appropriately recognized in the utility's return on equity.

Mr. Blakley testified that I&M's proposed special regulatory asset scheme makes the ratepayers responsible for the risk of all major storm damage expense in excess of the amount approved in rates. He explained that the entity that is in the best position to respond to a given event or take precautions against a given event should bear the consequences of the risk. He opined that the ratepayers are not in a position to do either and that as the owner and operator of its system, I&M should be appropriately incented to do both. Mr. Blakley stated that to the extent I&M can take steps to reduce the operating expense caused by major storm damage, it is not unreasonable that it be permitted to enjoy the financial benefits of costs avoided through its prudence and diligence. He also testified that even if I&M has no ability to avoid major storm damage expense, it does not make sense for its ratepayers to financially insulate I&M from major storm damage expense it incurs. Mr. Blakley testified that I&M's proposal might better be described as ratepayer-supplied insurance for major storm damage expense and that I&M's ratepayers are not currently nor should they be required in the future to participate in the business of insuring I&M from storm damage expenses.

Mr. Blakley testified that the long-established and accepted practice of providing a reasonable, pro forma amount of storm expense in base rates is reasonable and that I&M's proposal should be rejected. He stated that the pro forma amount can be calculated either using the test year, which may have some major storm activity, or if not, by using an average of years that include some major storm activity.

(c) <u>Industrial Group Case-in-Chief.</u> Mr. Selecky testified that the Commission should not approve I&M's proposal to create a Major Storm Damage Restoration Reserve and stated that, as a matter of policy, the Commission should limit the use of riders and tracking mechanisms because they shift regulatory risk from investors to customers. Mr. Selecky further testified that riders and tracking mechanisms undermine the Commission's ability to evaluate the sufficiency of a utility's rates in the context of a full rate proceeding, based on the totality of the utility's costs and revenues for a given test year. Mr. Selecky opined that a policy that permits a utility to adjust its rates for individual cost or revenues items outside of a rate case shifts regulatory risk from utility investors to customers by providing investors a guaranteed recovery of specific cost and revenue adjustments in utility rates. He added that this change in the Company's risk profile would occur without a corresponding reduction to its rate of return to recognize the reduced business risks faced by the utility. Mr. Selecky testified that a utility's allowed return on rate base is established to compensate the utility's investors for the various business risks it incurs, among them the risk that regulatory lag will delay the recognition of cost increases or revenue fluctuations in utility rates between base rate cases. He testified that utility investors are also compensated through the rate of return for bearing the risk that the utility's costs or sales revenues could fluctuate between rate cases relative to the levels embedded in the utility's rates.

(d) <u>SDI Case-in-Chief.</u> Mr. Smith testified that the Company's proposed Major Storm Damage Restoration Reserve would shift all risk of fluctuating costs from major storms that occur between rate cases away from investors and onto ratepayers without providing any commensurate benefit to ratepayers. He also stated that I&M had provided no reliable safeguards against it deferring costs during periods in which it may otherwise have excessive earnings. Mr. Smith testified that storm damage expense can be adequately addressed for ratemaking purposes without the need for piecemeal ratemaking and that I&M's proposal should be rejected.

(e) **I&M Rebuttal.** On rebuttal, Mr. Krawec explained that use of a reserve allows I&M to recover the true costs of a major storm without the need to use other funds already allocated to other necessary O&M activities. He also explained that, due to the nature of the reserve, which utilizes a true-up mechanism, the rates charged to I&M customers will ultimately reflect only the true costs of a major storm. Mr. Krawec testified that I&M's proposal recognizes that the cost to restore service following a catastrophic storm is a reasonable and necessary cost of providing service and that, because this can be volatile, I&M's proposal provides a reasonable means to reflect in the price for electric service the true cost of major storms. He reiterated that it is well established that reasonable and necessary costs of providing service are properly recognized for ratemaking purposes and that the question to address is how best to achieve this in the context of major storms. Mr. Krawec explained that traditionally basic rates are set with a normalized amount of major storm costs, that I&M in the past has incurred costs of major storms that far exceed the amount recognized for ratemaking purposes and that I&M can reasonably expect to incur such costs in the future.

Mr. Krawec explained the extraordinary efforts that a utility must undertake when a large storm damages electric systems. He testified that when large storms damage electric systems, a utility engages in a massive round-the-clock effort to restore power quickly and that such efforts can be daunting and costly. In addition to deploying the utility's own crew, the utility will call for assistance from other parts of the country and will thus incur the additional cost of these external crews such as wages, equipment rental, transportation, lodging, meals, etc. In addition, the utility will incur equipment costs, miles of new distribution or transmission lines, new poles, transformers, cross arms, fuses, etc. to replace what was damaged or destroyed by the storm. When the final costs are tallied, the bill can be financially devastating.

Mr. Krawec explained that, from a regulatory policy perspective, the utility should not be penalized in the ratemaking process for incurring this cost and that I&M's Major Storm Damage Restoration Reserve proposal avoids penalizing I&M for incurring this necessary cost of providing service. He also testified that it avoids the potential for a catastrophic storm to erode the Company's earnings and impair the Company's financial ability, impacts that adversely affect customers because they lead to increasing capital costs and diminish resources for other needs. In his direct testimony, Mr. Chodak explained that the Company faces significant capital expenditures and other challenges that make it very important for the Company to maintain adequate financial strength. Thus the adoption of the Major Storm Damage Restoration Reserve approach is a regulatory tool that is particularly appropriate to implement at this time.

Mr. Krawec explained that because severe storm-related costs are volatile and incurred at somewhat irregular intervals, they also defy attempts to predict their occurrence and that related costs simply cannot be budgeted accurately in advance. He further explained that while a "normalized" amount of major storm costs is recognized in the ratemaking process, I&M has and can incur costs that far exceed the normalized level, resulting in such costs eroding earnings and impairing the Company's financial integrity. Mr. Krawec testified that the cost I&M incurs to restore service in a timely manner can far exceed the "normalized amount" as evident with the $14 million and $15 million level of major storm expense in 2008 and 2005, respectively. He explained that the cost could be properly recognized by the filing of a general rate case or emergency rate case that reflects the cost in a test year. Mr. Krawec noted that a general rate case is a costly and resource intensive undertaking and that the Commission has not approved a petition for accounting authority to defer the cost of the major storm for recognition in a future basic rate case. He added that, if approved, such deferral accounting authority would mitigate earnings erosion.

Responding to the claims that I&M's Major Storm Damage Restoration Reserve proposal constituted single issue ratemaking, Mr. Krawec testified that it is not "single issue ratemaking" but is similar to other accounting and cost recovery mechanisms approved by the Commission and is designed to provide a reasonable means to reflect for ratemaking purposes volatile, irregularly occurring costs that are beyond the ability of a utility to accurately predict or to control when costs are incurred. Mr. Krawec testified that I&M's Fuel Cost Adjustment, for example, allows I&M to adjust rates to reflect changes in fuel costs. Fuel costs are volatile and irregular in the sense that, similar to major storm costs, they vary in amount from year-to-year and even day-to-day for a variety of different factors. Because fuel costs are volatile, irregular, and beyond the Company's control, the Commission has implemented an adjustment clause to provide for the recovery of fuel costs by I&M and other investor-owned utilities. In addition, the Commission has approved other rate adjustment mechanisms to track other non-fuel costs. For example, the Commission has authorized I&M and other utilities to use a rate adjustment mechanism to reflect costs associated with RTOs like PJM or the MISO. The purpose of these trackers, and I&M's proposed Major Storm Damage Restoration Reserve is to provide a ratemaking mechanism that better recognizes the actual cost of providing utility service, and to reflect in rates no more or less than the direct costs incurred as a result of major storms. He concluded by explaining that the only difference with the Major Storm Damage Reserve is the true-up occurs with the next rate case, which minimizes the administrative burden on the Commission and others.

(f) Commission Discussion and Findings. As noted above in our discussion of the appropriate level of major storm damage expense, all of the parties generally agree that the costs to restore power after a major storm event are substantial and highly variable. The record shows that these costs can range from as little as $0.9 million in a given year to $15 million or more. The parties also generally agree that the reasonable costs of restoring power after a major storm event are necessary to operating a utility and are recoverable in rates. The parties disagree, however, as to whether I&M's proposed Reserve is an appropriate and useful tool for addressing these costs or whether it inappropriately insulates the Company from major storm expenses.

Timely and safe service restoration following a major storm is vital to the ongoing operation of a utility. At times, the costs of such restoration may greatly exceed the amount of expense included in Petitioner's revenue requirement. This is one of the risks of engaging in the utility business, and that risk is traditionally borne by shareholders. In the past, the Commission has allowed a utility to seek recovery of extraordinary storm restoration expenses through a separate proceeding, but only when the storm at issue was a worst-case scenario. As we have recently seen, these stand-alone cases are often heavily litigated and highly contentious. Of course, the opposite situation also occurs, where the costs of storm restoration may be substantially less than the amount of expense included in Petitioner's revenue requirement. In those instances, ratepayers have essentially over-paid for that particular expense, and the utility has the use of the excess revenues to support other expenses or to include as a return to shareholders.

The accounting proposed by the Company to record under- or over-recoveries on a monthly basis as a regulatory asset or liability addresses both of these situations. Under the proposal, Petitioner's revenue requirement will include a base amount of storm damage expense, and the Company will record its actual expenses on an annual basis. In its next basic rate case filing, the Company will summarize the major-storm damage restoration reserve revenues and the major-storm restoration expenses. Once the Commission has reviewed those revenues and expenses and issued an order in that case, basic rates will be adjusted to resolve any under/over recovery positions and more closely align revenue recovery with expected expenses. And if the amount of imbedded storm damage expense exceeds the actual expense incurred, ratepayers will receive the benefit of the overpayment. Other parties to the subsequent rate case will retain the ability to challenge the reasonableness of the storm expenses included in the reserve account. By following that approach, the Commission is once again able to consider issues associated with the Reserve in the context of a rate case in which it has before it a variety of issues to consider in establishing I&M's revenue requirement and setting its rates.

The proposed accounting treatment will smooth out the impacts of major storms, thereby mitigating the financial consequences of a major storm. The availability of a reserve does not remove or diminish the Company's separate obligation to reasonably establish the level of storm costs and to manage that expense. In other words, it does not excuse the Company from prudently managing expenses associated with major storm expense. Therefore, based on the discussion above, we approve Petitioner's proposal to establish a Major Storm Damage Restoration Reserve.

(6) Nuclear Decommissioning Expense.

(a) I&M Case-in-Chief. J. Steven Kiser, Director of Trusts and Investments for AEPSC, discussed the nuclear decommissioning trust fund (the "Trust") established to decommission the Cook Plant at the end of its useful life, specifically addressing the annual contribution necessary to ensure adequate funds were available for the decommissioning. He explained that the current level for decommissioning funding of $8.1 million should continue to ensure the Trust has sufficient funding.

Mr. Kiser explained that the Trust is funded to ensure adequate funds to pay for the safe dismantlement of the Cook Plant and related facilities at the end of the useful life of the plant and to comply with certain State and NRC requirements. By funding the projected decommissioning costs now, customers who are receiving the benefits of the Cook Plant are allocated the costs to dismantle the asset. The NRC has established guidelines to ensure the adequacy of funds for the safe dismantlement, decontamination and disposal of nuclear generating units at the end of their useful lives. These guidelines apply to both the amounts of fund contributions and the methods for funding the ultimate decommissioning of the units. Mr. Kiser testified that the NRC regulations specify a minimum amount to be accumulated in the fund for the radiological portion of the decommissioning and require I&M to prepare a biennial certification of assurance demonstrating it has accumulated at least a minimum amount of decommissioning funds. He noted that the NRC required segregation of the Trust assets from I&M and that administrative control of the Trust be outside of I&M's control. Mr. Kiser explained that the Trust assets are held in a trust fund by The Bank of New York Mellon ("BNY Mellon"). Mr. Kiser stated that the investment decisions for the trust fund are made by an independent investment manager, NISA Investment Advisors, L.L.C. Mr. Kiser discussed this institution's performance and experience in managing both equity and fixed income investments in nuclear decommissioning trusts.

Mr. Kiser stated that the current balance in the Trust is below the NRC minimum but indicated that when factoring in assumptions about the investment return of the assets, as permitted by NRC regulations, the Trust balance satisfies these minimum requirements. Mr. Kiser emphasized that the NRC minimum requirements are a base level of funding necessary just to assure the safe dismantlement and disposal of the irradiated components of the plant and do not consider the cost of dismantling the plant buildings and non-radioactive portions of the plant. He stated that I&M believes that it has the obligation to restore the plant site to a Greenfield condition, *i.e.*, the plant site should be restored to a condition comparable to that prior to the construction of the plant. He added that the NRC requirements also do not include the storage cost for spent nuclear fuel and noted that those costs will be required until the DOE takes possession of spent fuel.

Mr. Kiser discussed the methodology used to determine an appropriate funding level. He explained that I&M had engaged Knight Cost Engineering Services, LLC to conduct a study (the "Knight Study") which evaluated 10 decommissioning scenarios and estimated the total decommissioning costs for the plant to range from $877 million to $1.5 billion in 2009 dollars. He said the scenario cost estimates depend on the decommissioning method used, the method of storing the spent nuclear fuel, the location at which the spent nuclear fuel would be stored, the presumed date at which the DOE would open the nation's spent fuel repository, the rate at which the spent fuel will be accepted at the repository, and the rate of inflation. He indicated that the decommissioning expenditures for Unit 1 are scheduled to begin in 2034 and the decommissioning expenditures for Unit 2 are scheduled to begin in 2037, which are the end of the NRC operating license lives. He added that complete decommissioning of the Cook Plant is expected to take many years and decommissioning costs could continue for up to 60 years after the plant is shut down.

Mr. Kiser explained how he used the costs from the decommissioning study to develop the proposed funding levels. He stated that the costs, expressed in 2009 dollars, were used as a base from which future decommissioning expenditures were projected. These expenditures were escalated from their 2009 base using the formula prescribed by the NRC for development of escalation rates for nuclear decommissioning costs. He explained that the NRC formula breaks the decommissioning costs into three components: labor, energy, and radioactive waste burial. The weight of each component is based on the detailed estimates in the Knight Study. The weighted annual inflation of all components comprises the total cost escalation for decommissioning. He stated that the purpose of escalating decommissioning costs is to ensure that cost forecasts account for the rate in which decommissioning costs are expected to increase over the long time horizon between now and the completion of the decommissioning process. He explained that for this case, the decommissioning cost escalation for the Cook Plant from 2009 to the expected end of the plant's life was based on historical updates of inflation components from the Bureau of Labor Statistics and recent estimates of waste disposal costs.

Mr. Kiser explained that the escalation rate is a combination of several components, and was calculated for each year in accordance with NRC requirements. He said separate forecasts were made for each of the formula's component pieces: the forecasted costs of labor, the rate of increase for energy costs, and the cost of radioactive waste disposal. Costs not included in those specific categories were escalated at the general rate of inflation. The components were then weighted according to the detailed estimates from the Knight Study. The weighted rates were then summed to determine the annual escalation rate for the cost to decommission the Cook Plant.

Mr. Kiser also discussed the asset classes for investments used in developing the estimates of investment returns. He testified that the major asset classes used were the broad categories of domestic equities, fixed income and cash. He said each of these asset classes has a long history which can be used to evaluate return potential, risks, and correlations with the other classes. The average rates of return used for the asset classes reflect the long term outlook, and are based on the rates used for setting the rate of return expectations for the AEP pension fund. He added that the rates for equities and cash were not adjusted for investment restrictions in the decommissioning trust funds. However, the rate for fixed income was adjusted to reflect the larger proportion of Treasury securities in the decommissioning trust fund compared to the pension fund.

Mr. Kiser explained that the Trust must pay taxes on the investment income and any investment gains that are realized in the portfolio. He said the taxes paid detract from the growth of the Trust, and reduce the amount of funds that will ultimately be available to pay for decommissioning expenses. He noted the current tax rate on the Trust is 20%. He discussed the steps that have been taken to minimize the impact of taxes on the investment portfolio.

Mr. Kiser explained how the asset allocation of the Trust investment portfolio will change over its life. The allocation will be changed as the planned date for decommissioning the plant draws near to reduce the amount of investment risk in the portfolio and to provide sufficient liquid assets to pay for decommissioning costs. When the start of decommissioning is imminent, the portfolio will be further shifted to hold more cash which will be drawn down to pay for the decommissioning expense. The exact timing of the asset allocation changes and the amount of the change will depend on the expected decommissioning expenditures and the timing of those expenditures. He stated that the projected changes in asset allocation were included in the modeling. Mr. Kiser explained that after all decommissioning expenses have been paid and the site is restored to Greenfield conditions, any funds remaining in the Trust would be returned to customers in a manner to be approved by the Commission. He said the decommissioning process and its related expenses could continue for decades after the shut-down of the plant depending on the decommissioning method used, the availability of a disposal site for the low-level radioactive waste, and the acceptance of the spent nuclear fuel by the DOE and its removal from the plant site.

Mr. Kiser explained that in previous filings, I&M has assumed that the DOE would fulfill its contractual obligation to accept and store spent nuclear fuel rods. However, since funding for the national spent fuel repository has been canceled, it has become more likely that the spent fuel will remain at the plant site indefinitely. He stated that in the Knight Study, one scenario included an open-ended cost for storing the spent fuel at the plant site. Scenario 10 in the study included costs of $4.4 million per year (in un-escalated 2009 dollars) for permanent storage of the spent nuclear fuel at the plant site. Mr. Kiser explained that for the projections performed for this case, the annual costs for the storage of the spent fuel were escalated out to year 2100.

Mr. Kiser explained that although the risk of an investment loss is commonly associated with an investment portfolio, the greatest risk to the Trust is the possibility of a shortfall - not having sufficient assets to fully pay for the cost of decommissioning the plant. He said the investment risk can be managed and minimized by building and continuously monitoring a diversified portfolio. He stated that the risk of a shortfall in the Trust is more difficult to manage and would be more difficult to recover from. A shortfall would mean that the Trust has failed to meet its basic objective of fully providing for the decommissioning of the Cook Plant. Since the decommissioning activities will continue for many years after the plant is removed from service, the existence of a shortfall and the extent of a shortfall may not be known for some time after the decommissioning process begins. Since annual contributions to the Trust would have already ceased and since the investments would be positioned in a conservative asset allocation to accommodate payments for decommissioning expenses, the shortfall could not be eliminated with either extraordinary gains or normal annual contributions.

Mr. Kiser explained the Monte Carlo simulation process he used to determine the likelihood of having sufficient assets available at the end of the Cook Plant's useful life to pay for the decommissioning expenses. He stated that recent advances in Monte Carlo simulation software allow the model and the trial runs it produced to be audited and verified independently. Mr. Kiser also presented the sensitivity matrix to illustrate the effects of a reduction in the annual funding amount recognized in the cost of service and discussed the most likely decommissioning scenario. Mr. Kiser concluded that the current rate of funding is likely to be sufficient based on the current accumulated balances in the fund and the currently projected decommissioning costs, given the uncertainties of future cost increases and investment returns. He explained that while there remains a substantial risk of funding failure, at this time, he does not recommend any change in the amount of contributions to the decommissioning trust.

(b) <u>OUCC Case-in-Chief.</u> Duane P. Jasheway, Utility Analyst in the OUCC Electric Division, recommended that no further contributions to the Trust for the Cook Plant be included in rates in this proceeding. He argued that the funding contributions are no longer necessary based on the current balance of the Trust and will lead to a further build-up of funds that he contends will not be needed to decommission the two Cook Plant units. He stated that if cost projections or earnings change at any time before the scheduled decommissioning of the units such that the existing funds no longer appear sufficient to fund the costs of decommissioning, then the need to resume decommissioning funding could be reevaluated at that time. He testified that the decommissioning scenario from the Knight Study favored by I&M – Scenario 10 – is 108.42% funded as of March 31, 2012.

Mr. Jasheway disagreed with Mr. Kiser's conclusion that it is better to have a larger surplus of decommissioning funds because any excess can be returned to ratepayers because he contends there is the potential for a significant balance of excess funds to be returned to future ratepayers who may not have received power from the Cook Units and may not have paid for any of the funding contributions that led to that excess.

Ronald L. Keen, Senior Analyst within the OUCC's Resource Planning and Communications Division, also addressed the funding of the Cook Plant decommissioning, noting that while Units 1 and 2 of the plant are currently scheduled to retire in 2034 and 2037, respectively, Mr. Kiser had previously testified that the Electric Power Research Institute ("EPRI") was researching additional life extensions. Mr. Keen stated that an additional extension beyond the current 2034/2037 license expiration dates to operate the Cook Plant would factor into the evaluation of the Trust's funding.

Mr. Keen discussed his review of the ten decommissioning scenarios analyzed in the Knight Study. The Study calculated cost estimates for each scenario in 2009 dollars. Based on his review, Mr. Keen believed that scenarios 8 and 10 are currently overfunded. He also expressed disagreement with Mr. Kiser's modification of the Knight Study cost estimates for scenarios 4 through 10 to reflect ongoing storage of spent nuclear fuel rods. Mr. Keen testified that the federal government is responsible for the permanent disposal of spent nuclear fuel rods and while the government has already breached its contractual obligations, it has paid damages to I&M and others to compensate them for this breach. Mr. Keen acknowledged that it is theoretically possible that I&M will be required to continue to maintain dry cask storage of spent nuclear fuel rods indefinitely, but he did not believe this result was likely because it assumed the federal government would continue not honoring its obligations and no advances in technology regarding the disposal of spent nuclear fuel rods in the next 80+ years. Mr. Keen described research being done to explore recycling spent nuclear fuel rods.

Mr. Keen explained that the OUCC believed I&M should seek 100% of the cost for the storage of the spent nuclear fuel from the federal government. He also recommended that I&M should demonstrate why the current overfunding of the decommissioning fund, combined with the interest the fund is earning on a monthly basis will not sufficiently cover the costs of the spent nuclear fuel storage out to 2100 should scenario 10 be selected. Mr. Keen acknowledged that the OUCC was not opposed to the inclusion of Greenfield costs to return the area back to native habitat.

(c) **SDI Case-in-Chief.** Mr. Smith testified that the market value of the Trust attributable to the Indiana jurisdiction was 71.5% of the total Trust. He stated that this was higher than the Indiana jurisdictional allocation of the Cook Plant, which he asserted was 64.65519%. Mr. Smith observed that I&M's FERC Form 1 indicated that its total asset retirement obligation for decommissioning the Cook Plant was $979 million and $930 million, respectively while the Trust assets were $1.3 billion and $1.2 billion, respectively. Mr. Smith concluded that I&M's nuclear decommissioning obligation has been adequately funded at this time, since the Trust's assets exceed the asset retirement obligation by $321 million. Mr. Smith further observed that the Trust balance exceeded the total cost estimates in the Knight Study for eight out of the ten scenarios, further suggesting the Trust may be adequately funded at this time.

Mr. Smith stated that if the Trust assets are growing faster than the liability (due to the after-tax earnings rate exceeding the cost escalation rate) then the funding sufficiency would continue to grow, even without additional funds being contributed to the Trust. He noted that I&M's assumptions for the return on the equities and cash in the Trust are the same used for the AEP pension plan, which had an assumed annual return of 7.75% for 2011.

Mr. Smith also discussed I&M's Monte Carlo analysis, which demonstrated that except for scenario 3, the probability is high that the Trust will be adequately funded if contributions of between $4 to $8.1 million are made. He recommended that the annual funding level be reduced from $8.1 million to $4 million per year. His recommendation was based on (1) a suggested Trust surplus of approximately $321 million, (2) the Trust assets attributed to Indiana exceed the jurisdictional allocation of the Cook plant; and (3) the Monte Carlo simulations run by I&M show high probabilities of sufficient funding at $4 million per year under all scenarios except scenario 3. In his cross-answering testimony, Mr. Smith testified that while the OUCC's recommendation is apparently not based on the results of I&M's Monte Carlo simulation runs, there appears to be merit in reducing the annual amounts to zero because of the current sufficiently funded status of the trust fund.

(d) I&M Rebuttal. Mr. Kiser responded to testimony offered by the OUCC and SDI on the funding level for the Trust. He clarified that the retirement dates for Units 1 and 2 of the Cook Plant are 2034 and 2037, respectively. Mr. Kiser explained that the Mr. Keen's confusion about the retirements stemmed from testimony regarding research performed by EPRI on life extension for nuclear plants that was not specific to the Cook Plant. He explained that I&M has not conducted any studies evaluating the ability to extend the Cook Plant's useful life by an additional 20 years. Mr. Kiser stated that EPRI research being undertaken on the feasibility of extending the lives of nuclear plants does not mitigate the need to fund the Trust because the NRC has not indicated that it would ever grant a license extension past 60 years to any nuclear plant.

Mr. Kiser responded to suggestions that the cost of storage for spent nuclear fuels should not be included in the estimate of decommissioning costs, noting that the storage of spent nuclear fuel will extend for many years. He disagreed that the DOE was likely to fulfill its legal obligation to pick up the spent fuel from the plant site and safely dispose of it. He opined that after the suspension of the development of the facility at Yucca Mountain, Nevada, the fiscal resources and political stamina that would be necessary to develop a new geological disposal facility are likely to be unobtainable. He also disagreed that recycling of the fuel was likely, noting that the Blue Ribbon Commission on America's Nuclear Future referenced by Mr. Keen stated succinctly that geological disposal remains the most promising and technically accepted method currently available for safely isolating high-level radioactive waste from the environment for very long periods of time.

Mr. Kiser also rejected Mr. Keen's belief that decommissioning costs were just as likely to decrease as to increase in the future. Mr. Kiser explained that the trend in costs has been up. He added that a significant portion of the decommissioning will be disposal of radioactive wastes, the costs of which has been increasing by 3% more than the rate of general inflation.

Mr. Kiser also disagreed that the Trust is already sufficiently funded and requires no further contributions. He explained why it is not appropriate to simply compare the current Trust balance as of March 2012 to the Knight Study decommissioning costs. First, he noted that the Knight Study's costs were calculated in 2009 dollars and would need to be inflated to compare them with 2012 dollars. He explained that a better analysis would escalate the individual cost components for decommissioning. The OUCC analysis also failed to take the taxes due on the unrealized gains into account in its analysis of the funding status of the Trust.

Mr. Kiser also highlighted flaws in Mr. Jasheway's calculations that the anticipated return in the assets of the Trust would be sufficient to ensure adequate funding at the end of the Cook Plant's useful life. First, he explained that Mr. Jasheway's average annual Trust appreciation of 7.88% included contributions from Indiana, Michigan and wholesale customers which amounted to 31% of the increase. Mr. Kiser explained that when one looks only at the actual investment rate of return from the fund, the return was 5.19% over a six year period. He stated that this level is slightly below the average return of 5.26% assumed in the Monte Carlo simulation. Mr. Kiser also explained that the asset allocation of the Trust will be shifted to less risky investments with lower returns as decommissioning approaches. This change will be made to reduce the risk in the portfolio and to provide sufficient available cash to pay for decommissioning expenses as they are incurred.

Mr. Kiser responded to Mr. Smith's recommendations that annual funding for the Trust from I&M's Indiana customers be reduced to $4 million. Notably, Mr. Smith's analysis inappropriately compared 2009 dollars to 2012 dollars. Mr. Kiser noted that his Monte Carlo analysis indicated that there is a one in three chance of a funding failure at Mr. Smith's recommended $4 million funding level. Mr. Kiser testified that such a level of risk does not correspond with a high degree of confidence for funding adequacy.

Mr. Kiser stated that Mr. Smith's comparison of the Trust balance to the asset retirement obligation for the Cook Plant as reported in FERC Form 1 is an invalid comparison. He explained that an asset retirement obligation ("ARO") recorded for accounting purposes is not the same as the true economic cost of decommissioning a plant. He stated that the ARO discount rate applied to the projected costs is calculated by a formula that includes I&M's debt rate and an adjustment determined by the current level of Trust funding. If the funding level is low, the annual ARO expense would be higher. Mr. Kiser also explained that using the corporate debt expense level renders the ARO sensitive to changes in that debt expense. He concluded that the ARO is an accounting concept that is not a reflection of the true economic cost of the future decommissioning of the Cook Plant.

Mr. Kiser disagreed that modification of the Trust funding was necessary to more accurately reflect the allocation of Cook Plant expenses to Indiana, Michigan and wholesale customers. He explained that the Trust has been accumulating for more than 29 years and that for the majority of that time, the demand allocation factor for the Indiana jurisdiction was more than 70% of the total. He explained that the current expense should be based on the current demand allocation factors, as reflected in his analysis.

Finally, Mr. Kiser responded to Mr. Smith's assumptions that the Trust will grow at a rate that exceeds the decommissioning cost escalation rate. He noted that it is impossible to know for sure what the growth rate for the Trust will be or what the escalation rate for decommissioning costs will be by the time the facility is decommissioned. Mr. Kiser explained that while the assumptions for equities and cash in the Trust were the same as those for the AEP pension plan, the overall return on the two funds are not comparable because the funds are very different. He testified that the expected return on the pension fund should not be used as a benchmark for the expected return on the Trust.

(e) Commission Discussion and Findings. The purpose of funding the nuclear decommissioning trust is to ensure that adequate funds are available to pay for the safe dismantlement of the Cook Plant at the end of its life and to comply with certain State and NRC requirements. The nuclear decommissioning expense is included in the revenue requirement to allocate the cost of decommissioning the plant to the customers who are receiving the benefits of its generation during its useful life. The funds collected must be placed into a trust account which neither I&M nor AEP can access for any purpose other than decommissioning the Cook Plant. Once the decommissioning is complete, any remaining funds will be returned to customers.

The parties disagree over the annual funding level of the Trust. I&M recommended continuing the current rate of funding of $8,100,000 annually. SDI and the OUCC recommended lower levels of funding—SDI initially proposed reducing annual funding to $4 million and subsequently noted that there is merit in the OUCC proposal to eliminate funding completely.

Mssrs. Keen and Jasheway recommended that no further funding of the Trust be authorized at this time. They reached that conclusion, in part, by comparing the balance of the Trust as of March 31, 2012, and concluding that in nine of the ten scenarios in the Knight Study, the estimated decommissioning costs were less than the March 31, 2012 balance of the Trust. Mr. Smith made a similar comparison. As of March 31, 2012, the unrealized gain on the trust assets is about $341 million and taxes on that unrealized gain would be about $68 million. That leaves a liquidation value, or the value of the fund that could be used to pay for decommissioning of $1,285,000,000. As Mr. Kiser explained, after adjusting the 2009 dollars and adjusting the market value of the trust assets for the taxes that will be due on investment gains in the trust, seven out of ten of the decommissioning scenarios are under-funded. Accordingly, we find that substantial evidence of record demonstrates that the Trust Fund is not adequately funded at present and continued contributions are required.

Mr. Smith proposed to reduce the annual funding for the Trust to $4 million based on his view that the funding levels achieved through March 31, 2012 are sufficient for most decommissioning scenarios. Mr. Smith's proposal balances the need to provide reasonable assurance that funding will be available to fully decommission the Cook Plant at the end of its useful life with the fact that under many possible decommissioning scenarios, the Trust Fund is at or near full funding. Therefore, we approve Mr. Smith's proposal to reduce the annual funding for the Trust Fund to $4 million dollars.

I&M requested that certain language be included in the Commission's Order to assist I&M in obtaining compliance with regulations of the Internal Revenue Service regarding qualified nuclear decommissioning trust funds. The language requested by I&M updates language incorporated into previous Commission rate orders. No party objected to this request. Accordingly, we incorporate the following disclosures into this Order:

(1) The amount of decommissioning costs to be included in the cost of service for Units No. 1 and No. 2 of the Donald C. Cook Plant is $2.00 million and $2.00 million, respectively.

(2) The assumptions used in determining the amount of the decommissioning

costs to be included in the cost of service for each of the two Units are as follows:

(a) The after-tax rate of return assumed to be earned by amounts collected for decommissioning is 5.26%.

(b) The proposed method of decommissioning each of the two Units is prompt removal/dismantling.

(c) The total estimated cost of decommissioning each of the two Units in 11/1/2009 dollars is $744,005,400 for Unit 1 and $744,005,400 for Unit 2.

(d) The estimated cost of decommissioning each of the two Units in future dollars for each year in which decommissioning expenses are expected to be incurred is as follows: $3,706,609,735 million (in escalated dollars) for Unit 1 and $3,706,609,735 million (in escalated dollars) for Unit 2 in total over the entire period included in the study described in item (h).

(e) The methodology used to convert the current dollars estimated decommissioning cost to future dollars estimated decommissioning costs is to use the formula $FV=PV\ (1+i)^{N}$ where "i" is 4.11% and "N" is the remaining life to license expiration.

(f) Decommissioning costs to be included in the cost of service are an amount of $4.0 million apportioned between units as shown in Item No. 1 expected to be included annually in the cost of service for each of the two units, continuing through the dates shown in Item (g), unless changed by future order of the Commission.

(g) The estimated date on which it is projected that the nuclear unit will no longer be included in I&M's rate base is October 31, 2034, for Unit 1 and December 31, 2037, for Unit 2.

(h) The Knight Study was utilized in determining the amount of decommissioning costs to be included in I&M's cost of service.

(7) **<u>Pre-April 7, 1983 Spent Nuclear Fuel Trust.</u>**

(a) <u>I&M Case-in-Chief.</u> Mr. Kiser said that the Nuclear Waste Policy Act of 1982, signed into law on January 7, 1983, established that the Federal Government had responsibility to provide for the permanent disposal of spent nuclear fuel and the costs of such disposal were the responsibility of the generators and owners of the spent nuclear fuel. The DOE promulgated rules under this Act that relate, in part, to the disposal of spent nuclear fuel from commercial nuclear reactors including the Cook Plant. In June 1983, I&M signed a contract with the DOE that provided, among other things, for payment of fees to the U.S. Treasury for such disposal. Mr. Kiser explained that the contract consisted of fees derived by two cost mechanisms. One mechanism was a one-time fee for nuclear fuel spent to generate electricity at civilian nuclear power reactors prior to April 7, 1983 ("Pre-April 7, 1983"). He stated that the second mechanism was a fee per kilowatt-hour of generation for spent nuclear fuel resulting from the generation and sale of electricity on or after April 7,1983 ("Post-April 7, 1983"). So, in addition to the liability for decommissioning the nuclear plant, I&M also has an obligation to the DOE to pay for the disposal of spent nuclear fuel used prior to April 7, 1983. Mr. Kiser explained that the obligation is a fixed amount that increases with interest accumulated each year. Amounts included in the fuel cost adjustment mechanism for the Post-April 7, 1983 spent nuclear fuel disposal costs are required to be deposited quarterly with the U.S. Treasury. He stated that those deposits will continue at the present level unless the U.S. Congress changes this program. Those amounts do not directly affect decommissioning.

Mr. Kiser explained that on a total Company basis, the initial liability for Pre-April 7, 1983 spent nuclear fuel disposal was $71,963,830. The liability increases each quarter based on the most current yield for 3-month Treasury bills. It has increased through the accumulation of interest to $265,001,448 as of March 31, 2011, and will continue to increase in the future. Mr. Kiser stated that based on an energy allocation factor of 63.48797%, the Indiana jurisdictional liability as of March 31, 2011, was $168,244,040.

Mr. Kiser explained that BNY Mellon holds the spent nuclear fuel trust fund, which is considered to be a non-qualified fund. As such, contributions to it are not tax deductible and investment income and capital gains are subject to the corporate income taxes. Mr. Kiser stated that to help mitigate the tax burden on the trust fund's earnings, the fund is invested in tax-free pre-refunded municipal bonds.

Mr. Kiser testified that as of the end of the test year, the Indiana jurisdictional portion of I&M's spent nuclear fuel trust fund had a market value of $218,047,382. Mr. Kiser explained that the spent nuclear fuel trust is greater than the spent fuel liability allocated to the Indiana jurisdiction, so the trust may be considered fully funded for the Indiana jurisdiction. Mr. Kiser stated that it is important to note that this liability will continue to increase through the accrual of additional interest until paid. He added that the liability can move from fully funded to less than fully funded through changes in the market value of trust fund securities, differences between the liability accretion rate and the investment earnings rate and other factors. He recommended that there is no current need to resume funding for the Pre-April 7, 1983 spent nuclear fuel disposal fund.

(b) <u>Commission Discussion and Findings.</u> No party opposed Mr. Kiser's recommendation regarding funding for the Pre-April 7, 1983 spent nuclear fuel disposal fund. Having reviewed the evidence on this issue, we find that the funding for the Pre-April 7, 1983 spent nuclear fuel disposal should remain suspended for the time being. I&M shall continue to monitor the level of funding for nuclear decommissioning and for Pre-April 7, 1983 spent nuclear fuel disposal and shall report to the Commission on these matters every three years.

(8) <u>Cook-Unit 1 Outage O&M Expense.</u>

(a) <u>OUCC Case-in-Chief.</u> Mr. Eckert identified expenses associated with the Cook Unit 1 outage in test year pro forma operating expense. The OUCC recommended these amounts be excluded from operating expenses.

(b) **I&M Rebuttal.** On rebuttal, Mr. Krawec reiterated his testimony during the February 2012 hearing in this Cause that it was I&M's intent to exclude these expenses from the cost of service on the basis that the costs were out of period and related to an extraordinary event. He identified Petitioner's Rebuttal Exhibit A-R5 (Confidential), O&M Adjustment R40 as reflecting the removal of these expenses as proposed by Mr. Eckert.

(c) **Commission Discussion and Findings.** The parties agree that expenses related to the Cook Unit 1 outage should be removed from pro forma test year operating expense. Therefore we approve Petitioner's O&M Adjustment R40 as reflected on Petitioner's Exhibit A-R5 (Confidential).

(9) **Legal Expenses.**

(a) **OUCC Case-in-Chief.** The Company's proposed revenue requirement reflected the test year amount for legal expense. Ms. Stull proposed to disallow the full amount of the test year outside legal expenses in the amount of $2,367,861 (Total Company) and $1,590,445 (Indiana Jurisdictional). She stated that she proposed the exclusion because she was not able to receive all the information she wanted regarding legal expenses. In the discovery process Petitioner produced invoices with privileged and confidential information redacted. At the hearing Ms. Stull acknowledged that she had subsequently received additional information. She also conceded that I&M incurred legal expense prior to the test year and has and is reasonably expected to continue to incur legal expense after the test year. The total legal expense noted above included a proposed exclusion presented by Mr. Blakley. Mr. Blakley proposed to eliminate the test year legal and consulting expenses of $204,602 (Total Company) or $137,560 (Indiana Jurisdictional) associated with I&M's purchase of the assets of Fort Wayne City Light and Power ("FWCLP") pursuant to the settlement agreements approved by the Commission in Cause No. 43980. Mr. Blakley contended that these expenses were non-recurring. He did not contend the amounts incurred were excessive, unnecessary or not representative of ongoing expenses.

(b) **I&M Rebuttal.** Mr. Krawec disagreed with the OUCC's proposal to exclude all test year legal expense. Mr. Krawec explained that the costs incurred for the purchase of the FWCLP were part of settlement agreements with the OUCC and Fort Wayne, which the Commission approved. Mr. Krawec explained that I&M continues to incur legal expenses related to the implementation of the FWCLP. He added that this type of cost is a normal expense. He explained that while the nature of the legal issue/representation may change, the incurrence of the expense will not. Mr. Krawec testified that the FWCLP cost at a minimum should be reflected in the ratemaking process via a three-year amortization, not wholly excluded. Mr. Krawec also provided data showing that the inclusion of legal and consulting fees associated with the FWCLP did not contribute to an excessive expense level or one that is unrepresentative of an ongoing level of expense. This data showed that I&M's test year level is conservative, yet representative of the ongoing level of legal expenses I&M expects to incur. More specifically, Mr. Krawec showed that the test year level of legal expense is the lowest level when compared to the preceding and succeeding 12-month periods and the average of the three periods.

(c) **Commission Discussion and Findings.** Test year levels of revenue and expense are presumed to be reasonable. A party proposing an adjustment to the test year bears the burden of proof with respect to that adjustment. Here, the OUCC has not demonstrated that the test year legal expenses, including the FWCLP costs, are unreasonable or not representative of a type of expense the utility incurs on an ongoing basis. We find that the OUCC has not supported its proposed adjustment to remove all test year legal outside counsel expense and the OUCC's adjustment to eliminate legal expenses will result in a level of legal expense in I&M's cost-of-service that is not representative of ongoing utility operations. Therefore, we find that I&M's test year legal expenses, including the FWCLP costs, should be reflected in the revenue requirement used to establish rates in this proceeding.

(10) Rate Case Expense.

(a) I&M Case-in-Chief. Petitioner proposed to include in pro forma rate case expense amounts of $47,521 (Indiana Jurisdictional) for Communications Counsel of America (CCA) Training and $55,280 (Indiana Jurisdictional) for the Nuclear Decommissioning Study. Mr. Krawec adjusted the test year operation expense to reflect the amortization of retail rate case expense and nuclear decommissioning study expense over a period of three years.

(b) OUCC Case-in-Chief. Mr. Eckert opposed the inclusion of the cost of the Nuclear Decommissioning Study in pro forma proposed rate case expense because, according to Mr. Eckert, the costs of the study were incurred and paid prior to the beginning of the test year and I&M did not receive Commission authority to defer the cost of the study. He also disagreed with the inclusion of the cost of CCA Training in I&M's proposed rate case expense calculation because, he contended, the services provided and skills sets obtained from the training can be used for more than just this rate case, particularly by witnesses who are AEPSC employees and can use the services and skill sets for other AEP companies for whom they provide services. Finally, Mr. Eckert recommended Petitioner amortize its rate case expense over four years instead of three.

(c) I&M Rebuttal. Mr. Krawec cited the Commission's March 23, 1983 Order in Cause No. 36760 S1 at 8-9, which stated:

> Therefore, we find that the adequacy of the annual provision [for nuclear decommissioning] should be reviewed as an element of cost-of-service in each subsequent rate case brought by Petitioner before this Commission. In the event that three years elapse between Petitioner's rate case filings, Petitioner shall then separately review and report to the Commission on the adequacy of the then existing annual provision.

He explained that I&M's filing in this case complies with the directive in that Order. He stated it is not reasonable or fair for I&M to be required to incur the expense of a nuclear decommission study every three years and not allow I&M to recover the cost of complying with this regulatory requirement. Mr. Krawec pointed out that the OUCC relied upon the report to support its recommendation to remove nuclear decommissioning expense from I&M's rates. He testified that the nuclear decommissioning study costs are costs I&M will continue to incur in the future, with the next report to be submitted to the Commission in late 2012.

Mr. Krawec also disagreed with Mr. Eckert's recommendations concerning CCA training. He explained that the CCA was retained to educate the subject matter experts on the Indiana ratemaking process and the specific issues in this case to assist those experts in communicating with the Commission and other parties to this proceeding. He stated this type of case-specific regulatory training and communication is outside the scope of the subject matter witnesses' day to day duties and the cost of acquiring and maintaining these services other than through a service such as CCA would be much greater.

Mr. Krawec disagreed with the OUCC's request to amortize the retail rate case expense over a period of four years, asserting that the three year period proposed by I&M is a reasonable approximation of the period of time that rates established in this Cause will be in effect. Moreover, he explained, as it pertains to the nuclear decommissioning study, this study is performed every three years and therefore it is appropriate to include a three year amortization of that study in the cost-of-service.

(d) Commission Discussion and Findings. In our Order in Cause No. 36760 S1, we required I&M to incur the expense of a nuclear decommissioning study for each rate case (or every three years in the absence of a rate case). Thus, the cost of a nuclear decommissioning study is a necessary cost of providing service. We note that no party contends the expense was excessive. Likewise, no party contends that the amount of expense is not fixed, known and measurable. Rather the proposed exclusion is based on the argument that I&M incurred this particular rate case expense outside of the twelve-month test period. The record reflects that I&M incurred the cost of the nuclear decommissioning study to comply with the regulatory mandate and to provide for the efficient preparation of its rate case filing. Because I&M is required to provide a nuclear decommissioning study every three years, disallowing these costs would mean that the cost of service reflected in the revenue requirement is not representative of ongoing utility operations. It would also deny I&M the ability to recover the cost of the regulatory mandate imposed in Cause No. 36760-S1. Because the test year level of rate case expense is not representative we find this required part of rate case expense is appropriately recognized in the revenue requirement as an in-period test year adjustment. Accordingly, we reject the OUCC's recommendation to exclude of the nuclear decommissioning study expense from rate case expense.

With respect to the inclusion of CCA training in rate case expense, we find that Petitioner has provided sufficient evidence to support its position, showing that the expense was prudent and incurred specifically for this case. We therefore reject the OUCC's proposed exclusion of this amount in pro forma rate case expense.

Finally, we find that Mr. Krawec's rebuttal testimony provided adequate justification for use of a three year amortization period for rate case expense and that Mr. Eckert has failed to provide sufficient evidence for using a four year period instead. Accordingly, we approve I&M's proposed three year amortization for rate case expense.

(11) Non-Allowed/Non-Recurring Expenses.

(a) OUCC Case-in-Chief.

(i) **Non-Allowed Expenses.** Ms. Stull proposed to eliminate certain expenses totaling $2,144,452 (Total Company) and $1,443,378 (Indiana Jurisdictional) from Petitioner's O&M expenses as follows: Community Relations (Total Company $751,839/Indiana Jurisdictional $505,282); Indiana Governmental Relations (Total Company $339,240/Indiana Jurisdictional $228,017); Michigan Governmental Relations (Total Company $200,016/Indiana Jurisdictional $135,917); I&M Communications (Total Company $415,145/Indiana Jurisdictional $279,301); I&M External Communications (Total Company $178,878/Indiana Jurisdictional $120,252); and Miscellaneous Non-Allowed Expenses (Total Company $259,334/Indiana Jurisdictional $174,609). She cited Ind. Code § 8-1-2-6(c) in support of her adjustments, stating that the costs incurred for institutional or image-building, charitable contributions, community relations, marketing, and lobbying expenses are not allowed for ratemaking purposes and that these costs provide no material benefit to ratepayers and are not necessary for the provision of electric utility service. Ms. Stull testified that she excluded transactions from her adjustment that Petitioner had already eliminated such as advertising expenses, Indiana Energy Association dues and regulatory expenses as well as all "below the line" transactions since I&M has not included them in its proposed revenue requirement. She explained that since the Commission previously ruled that Chamber of Commerce dues are allowed in rates she did not include them in her adjustment. Ms. Stull explained that she based her proposal on the name of particular departments. Using this approach she said she eliminated 50% of the Communications Department and the External Relations Department because they also provide necessary communications for employees and ratepayers. Ms. Stull proposed to eliminate 100% of the costs incurred by the Governmental Relations and Community Relations departments.

Ms. Stull also testified that she excluded $97,357 (Total Company) or $65,456 (Indiana Jurisdictional) administrative costs related to the AEP Service Company's Washington, D.C. office. She testified that I&M recorded the majority of the allocated costs related to the Washington, D.C. office below the line and excluded the costs from the revenue requirement. She further explained these administrative costs would not have been incurred absent the existence of the Washington D.C. and the costs should be excluded from the revenue requirement.

(ii) **Cook Plant Fire Suppression System.** Mr. Eckert recommended $1,775,761 in total Company expense and $1,148,122 in Indiana Jurisdictional expense associated with the replacement of the Cook Plant fire suppression systems be eliminated from O&M expense as a one-time non-recurring expense.

(b) **I&M Rebuttal.**

(i) **Non-Allowed Expenses.** Mr. Krawec testified that Ms. Stull's removal of expenses based on the title of the department that incurred the expense was not appropriate. He explained that she performed an inadequate review by basing her determination on the title of the department, not the nature or type of expense incurred. He explained that departments are used by I&M strictly for budgeting purposes and that the department code does not drive the accounting for the costs incurred within that department. Mr. Krawec also testified that all departments charge the appropriate FERC account based on the type of work being done, that I&M follows the FERC USOA guidelines to determine when expenditures should be classified as capital or O&M and that charges are included in above-the-line FERC accounts or below-the-line FERC accounts (recoverable/not recoverable) based on the type of work being done.

Mr. Krawec responded to Ms. Stull's removal of 100% of the costs recorded by Department 10892-Community Relations by explaining that I&M's Community Relations department handles a variety of tasks such as employee communications, customer communications, energy education, special events, and public information for emergency preparedness and serves as the primary point of contact for City and County officials in regards to economic development, safety, outages, crisis management and other key issues as they arise. He also testified that I&M Community Relations personnel provide communication on I&M policies, plans and programs; I&M's position on specific issues of concern to the Company or industry; and, news of specific issue developments and events as they occur and that it plays a significant role in I&M's economic development activities. Mr. Krawec also testified that I&M's economic development activities further the Company's mission of supporting business and commerce and building strong communities and that I&M's Community Relations employees, in addition to their other job duties and responsibilities, coordinate and support traditional local economic development activities, including community preparedness, business recruitment, and business retention. He testified that these are not "non-allowed" activities as Ms. Stull contended; in particular, customers benefit from I&M's Community Relations efforts because they are better prepared to use energy efficiently and safely by the information provided through the communication materials and that the materials help customers have a better understanding of actions the utility is taking on their behalf.

Mr. Krawec testified that I&M agreed that certain additional expenses should have been either recorded below-the-line or removed from the case as "image-building." He explained that I&M's audited the $751,839 (Total Company) amount which Ms. Stull recommended be removed. He explained that the audit resulted in below-the-line or image building expenses of $13,787 (Total Company) or $9,269 (Indiana Jurisdictional) that should be removed from the revenue requirement. He testified that the remaining expenses recorded by I&M's Community Relations department were prudently incurred and are appropriate to include in I&M's revenue requirement.

Mr. Krawec testified that Ms. Stull's recommendation to remove 50% of the costs recorded by Department 12085-Communications was not appropriate, explaining that I&M's Communications department is responsible for internal employee communications. He explained that the audit identified actual below-the-line or image building expenses in the amount of $13,915 (Total Company) or $9,355 (Indiana Jurisdictional) that should be removed from the revenue requirement. He identified the activities I&M Communications department externally responds to and the variety of media used to communicate safety, storm, and educational information to its customers.

Mr. Krawec testified that Ms. Stull's removal of 100% of the costs recorded by I&M's managers of state government affairs to Department 10384-IN Governmental Relations was not appropriate and explained that Ms. Stull incorrectly equated the department titles of "Governmental Relations" with "lobbying." He explained that the I&M State Government Affairs personnel work on various non-lobbying activities including the day-to-day monitoring of not only state legislation matters, but also certain federal bodies, such as Congress and the FERC, which regularly take actions affecting utility companies, including I&M. He explained that these employees also work with government representatives to educate and inform them regarding utility and customer issues critical to utility operations and customer service and the employees monitor issues that may impact I&M's nuclear plant.

Mr. Krawec explained that I&M recognizes that a portion of the State Government Affairs personnel time may be spent on lobbying activities and has reviewed the accounts to determine what additional amount, if any, should be recorded below-the-line. He explained that I&M determined that the costs (Total Company) recorded by Department 10384-IN Governmental Relations are as follows:

Labor and related employee expenses	$229,211
Outside Services	$52,297
Office Space	$51,718
Other	$6,014

He explained that the Company has already removed the labor and related employee expenses associated with lobbying activities to eliminate those expenses for the test year levels. He testified that I&M disagreed that 100% of the labor and related employee expenses for the State Governmental Affairs employee should be removed from the revenue requirement. He explained that upon reviewing the OUCC's testimony, I&M undertook a review of the activities of the employee that can be reasonably expected going forward to determine a representative amount to be included in I&M's revenue requirement. Based on this review, Mr. Krawec determined that the test year amount should be adjusted to exclude 15% of the employee's expenses from the revenue requirement. Mr. Krawec also testified that the office space charges reflected in the test year are for rents associated with I&M's Indianapolis office. He explained that this office is used by numerous I&M employees, including I&M's President, Vice President of External Affairs, Director of Regulatory Services and State Government Affairs employee and is used as an off-site office for employees traveling to Indianapolis for various activities, including hearings, workshops and meetings with the Commission, OUCC and other stakeholders. Mr. Krawec explained that I&M disagreed that 100% of the expenses associated with the Indianapolis office should be removed, but agreed that a portion should be removed. He testified that considering the portion of time that the Department 10384 State Government Affairs employee spend on lobbying activities (15%) and the considerable amount of time others use that office for non-lobbying activity, I&M agreed that 10% or $5,172 (Total Company) associated with the Indianapolis office should be removed from the cost-of-service reflected in the revenue requirement.

I&M agreed to remove Department 10384 amounts as follows:

$34,382 - 15% of the labor and related expenses of $229,211 (Total Company)
$52,297 - 100% of outside services of $52,297 (Total Company)
$ 5,172 - 10% of the office space costs of $51,718 (Total Company)
$ 6,014 - 100% of the Other costs of $6,014 (Total Company)

Mr. Krawec explained that this results in an adjustment of ($97,864) (Total Company) or

($65,797) (Indiana Jurisdiction) from the cost of service.

Mr. Krawec testified that after reviewing Ms. Stull's removal of 100% of the costs recorded by Department 12381-MI Governmental Relations, I&M reviewed the costs recorded by Department 12381 to determine the employee time associated with below-the-line activities (30%) and for other activities (70%). He explained that based on that analysis, I&M proposed to remove 30% of the rent/lease amount of $52,118 (Total Company) resulting in an adjustment of $15,635 (Total Company) or $10,512 (Indiana Jurisdictional).

Mr. Krawec testified that Ms. Stull's removal of 50% of the costs recorded by Department 12380-I&M External Relations was not appropriate, explaining that the test year expenses in Department 12380 are related to the work performed by I&M's Vice President of External Affairs, Marc Lewis, who spent time on numerous regulatory issues impacting I&M. Mr. Krawec explained that, as in previous years, during the test year, Mr. Lewis participated in numerous Commission investigations and inquiries and Mr. Krawec provided various examples of this ongoing work.

With respect to Ms. Stull's proposal to remove 100% of the costs of "Other Miscellaneous Non-Allowed Expenses," Mr. Krawec agreed that $95,828 (Total Company) or $64,222 (Indiana Jurisdictional) should be removed as shown on Petitioner's Exhibit SMK-R3. He explained that the remaining expenses are appropriate as these expenses include costs related to various items including employee activities, employee education and safety. He explained how these activities result in a safer and more productive work force, encourage growth in leadership and creativity skills, emphasize to employees the value that the Company places on maintaining an experienced and stable work force and, thus, give recognition to those employees who have benefitted the Company and its customers by achieving safety goals, operational goals and reducing employee turnover. He also testified that reduced turnover results in a savings of costs for recruiting, hiring, training and education of new employees.

Mr. Krawec testified that Petitioner's Exhibit SMK-R3 reflects expenses for an Informational Center Open House which were incurred to develop employee engagement and focus for safety issues for all I&M Cook nuclear plant employees, including new outage workers, and temporary outage workers assigned to I&M's Cook Nuclear Plant. He also testified that the costs Ms. Stull sought to exclude go beyond employee recognition and safety events. He explained that the proposed exclusion reflects costs incurred for I&M's association with Midwest Ozone Group ("MOG"). Mr. Krawec explained that MOG is an affiliation of companies, trade organizations, and associations which draw upon their collective resources to advance the objective of seeking solutions to the development of a legally and technically sound national ambient air quality program based upon the use of sound science. Mr. Krawec testified that this expense is prudent and reflects I&M's commitment to maintaining I&M's low cost of service, thus benefiting customers.

Mr. Brubaker explained that the test year costs of the AEPSC Washington, D.C. office reflected in the Company's proposed revenue requirement ($65,456 Indiana Jurisdictional) do not include lobbying costs. He testified that while certain AEPSC employees in the Washington, D.C. office perform both a lobbying function as a portion of their job duties as well as other non-lobbying activities for the benefit of the affiliate companies, including I&M, other AEPSC employees in the Washington, D.C. office perform only non-lobbying activities for the benefit of the affiliate companies, including I&M. He explained how the costs of the Washington, D.C. office are recorded to the appropriate above-the-line or below-the line FERC accounts based upon the specific tasks performed each day. He said the Federal/External Affairs team in the Washington, D.C. office monitors and participates in rulemakings and other public policy discussions at various federal agencies, such as the FERC, the Securities and Exchange Commission (SEC), and the EPA as part of their responsibilities. In addition, the employees of the Washington, D.C. office assist in developing the quarterly and annual reporting disclosures related to these legislative items required by the FERC and the SEC. Mr. Brubaker concluded that these types of legislative monitoring and reporting tasks are reasonable business expenses, that would be incurred regardless of any lobbying activity, and it is appropriate that the test year amount of $65,456 be recoverable in the revenue requirement used to establish basic rates.

(ii) <u>Cook Plant Fire Suppression System (NFPA 805 Costs).</u> Mr. Chodak clarified that while the NFPA 805 project was a one time compliance cost, the cost of this project spanned multiple years. Mr. Chodak added that this regulatory compliance cost is representative of ongoing compliance costs. Mr. Krawec disagreed with Mr. Eckert's contention that the expense associated with the replacement of the fire suppression system at the Cook Plant should be eliminated for ratemaking purposes. Mr. Krawec testified that Mr. Eckert failed to recognize the driver behind the activity resulting in the expense, which as Mr. Chodak explained, was required by federal regulations, NFPA 805. Mr. Krawec also explained that while the fire suppression system replacement may be a one-time activity, the driver is emerging/changing/developing Federal regulations that will continue to cause I&M to incur O&M expenses. Mr. Chodak noted that Mr. Eckert conceded that the work was performed to support a regulatory requirement and that the OUCC did not dispute that I&M reasonably incurred the cost as part of its operations or that the amount of the expense was reasonable, but it nonetheless recommended that the expense be disallowed as a nonrecurring expense. Mr. Chodak and Mr. Krawec explained that the Company will continue to incur costs to comply with NFPA 805 on a going forward basis. They also explained that as new regulations are passed, and as current ones are revised, the Cook Plant will incur expenses for work necessary to be in compliance and that the associated cost of compliance will likely increase. Mr. Chodak and Mr. Krawec concluded that I&M properly included the test year level of expenses in its proposed revenue requirement because these costs are representative of normal operations. These witnesses concluded that I&M's test year O&M expenses are necessary to the provision of service and are representative of normal operations, and as such this type of expense is properly recognized for ratemaking purposes.

Mr. Krawec testified that if the Commission finds that the test year cost of the fire suppression system is a non-recurring extraordinary expense, the cost should not be excluded for ratemaking purposes because it is a reasonable and necessary cost incurred to provide utility service. He explained that, at a minimum, this cost should be recognized for ratemaking purposes by amortizing the cost of the Fire Suppression System over a period of three years.

(c) <u>Commission Discussion and Findings.</u>

(i) <u>Non-Allowed Expenses.</u> We approve the following reductions to the test year identified by Mr. Krawec on rebuttal:

Expense Category	Amount of Expenses Reduction
Community Relations	\$13,787 (Total Company)/\$9,269 (Indiana Jurisdictional)
State Government Affairs	\$97,864 (Total Company)/\$65,797 (Indiana Jurisdictional)
MI Governmental Relations	\$15,635 (Total Company)//\$10,512 (Indiana Jurisdictional)
Miscellaneous Non-Allowed Expenses	\$95,828 (Total Company)/\$64,222 (Indiana Jurisdictional)

We reject Ms. Stull's proposal to eliminate certain expenses totaling \$2,144,452 (Total Company) and \$1,443,378 (Indiana Jurisdictional) from Petitioner's O&M expenses as follows: Community Relations (Total Company \$751,839/Indiana Jurisdictional \$505,282); Indiana Governmental Relations (Total Company \$339,240/Indiana Jurisdictional \$228,017); Michigan Governmental Relations (Total Company \$200,016/Indiana Jurisdictional \$135,917); I&M Communications (Total Company \$415,145/Indiana Jurisdictional \$279,301); External Relations (Total Company \$178,878/Indiana Jurisdictional \$120,252); and Miscellaneous Non-Allowed Expenses (Total Company \$259,334/Indiana Jurisdictional \$174,609). We find that the Company's expense levels, reduced to reflect the amounts identified by Mr. Krawec on rebuttal, are reasonable.

While we are aware Ind. Code § 8-1-2-6(c) provides that the Commission "may not take into consideration or approve any expense for institutional or image building advertising, charitable contributions, or political contributions," Ms. Stull did not correctly apply this standard. Instead, as I&M established, Ms. Stull's analysis was predicated on a superficial review of information provided by the Company, which analysis included a misplaced reliance on the title of a particular department without sufficient consideration of the actual activities underlying the expenses recorded in the account. To correctly determine whether expenses run afoul of the prohibitions enunciated in Ind. Code § 8-1-2-6(c), one must undertake an analysis of the actual activities performed in light of the actual statutory language. To assess advertising and lobbying expense, the Commission's rule (170 IAC 1-3-3) and precedent provides for an assessment whether such activities provide a material benefit to customers. The cost of other test year activities are presumed to be reasonable and necessary business expenses.

We concur with I&M that its communication activities providing safety, storm and educational information and economic development information materially benefit customers. We similarly agree with I&M that the Company's non-lobbying activities to monitor state and federal issues, to educate and inform government representatives regarding utility and customer issues critical to utility operations and customer service are reasonable and necessary and properly included in operating expenses and recovered in rates. These activities also benefit customers. I&M also sufficiently established that it is reasonable and necessary to maintain an Indianapolis office to support Company involvement in such activities as hearings, workshops and meetings with the Commission, OUCC and other stakeholders and other non-lobbying activities. We find that the associated costs are properly included in operating expenses and recognized for ratemaking purposes. We also find that I&M has sufficiently established that the costs Ms. Stull included in "Other Miscellaneous Non-Allowed Expenses" represent costs associated with the types of education, safety and other reasonable and necessary employee activities and are thus appropriately recognized in the revenue requirement.

Based upon these findings, including approval of the adjustments proposed by Mr. Krawec on rebuttal, we find that I&M is authorized to include in operating expenses for ratemaking purposes, the test year expenses for Community Relations, Communications, Government Relations, External Affairs and in the category referred to as "Other Miscellaneous" expenses, including the cost of the AEPSC Washington, D.C. office, as reflected in the Company's case-in-chief and adjusted in the Company's rebuttal testimony and exhibits. Based on our findings, we conclude that Petitioner's total pro forma cost for the foregoing is $1,284,222 (Indiana Jurisdictional).

(ii) <u>Cook Plant Fire Suppression System.</u> We find I&M's explanation that one-time specific expenses incurred during the test year replaced one-time expenses that were incurred prior to the test year and will subsequently be replaced by new one-time expenses that will be incurred in the future and that these type expenses are properly included in operating expenses subject to rate recovery. We have previously recognized that the test as to whether certain expenses are recurring or not concerns whether those types of expenses are expected to occur in the future, not whether those specific expenditures will recur. The OUCC's proposal to exclude these costs fails to demonstrate that these costs are unrepresentative of a type of ongoing expense. Further, we find that the record shows that the NFPA 805 project costs were not limited to the test year. We further find the record shows that such compliance costs have and will continue to be incurred on a going forward basis. We further find, therefore, that I&M properly included the test year Cook Plant Fire Suppression expenses in its proposed revenue requirement because these costs are representative of normal operations to comply with current, ongoing and future regulations. Accordingly, we find that the test year expenses associated with the Cook Plant fire suppression system/NFPA 805 compliance constitute recurring expenses because they represent the type of expenses that are expected to occur in the future, thus meeting the standard for cost recovery that we enunciated in prior cases. With respect to whether actual level of these expenses is reasonable and prudent, there was no dispute as to the reasonableness of the amount of the expense. We therefore find that the Company's pro forma Indiana Jurisdictional expense level for the Cook Plant fire suppression system/NFPA 805 compliance is $1,148,122 and that this amount is properly included in operating expenses for ratemaking purposes because it is part of an overall expense that is representative of I&M's ongoing operation and maintenance expense.

(12) <u>Workforce and Cost Reduction Initiative.</u>

(a) <u>I&M Case-in-Chief.</u> Mr. Chodak and Mr. Krawec explained that during the test year the Company implemented cost reduction initiatives to reduce its workforce. Nearly 2,500 positions were eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. This cost reduction initiative reduced the Company's cost of providing service, including reductions in payroll and associated employee benefits costs. Mr. Brubaker presented various adjustments to the test year to pass these savings to the customers by normalizing the test year data to reflect the effect of a reduced workforce.

Mr. Krawec explained that as a result of the cost reduction initiative undertaken by AEP and I&M, AEP recorded a $293 million pretax expense on a total system basis related to these cost reduction initiatives with I&M's total company share of these costs incurred during the test year being \$43.5 million. He stated that the Indiana jurisdictional retail share of this amount is approximately \$30 million. Mr. Krawec explained that the Company has adjusted the test year operating expense levels to remove the one-time expense of the cost reduction initiative. He added that the adjusted test year O&M reflects the ongoing savings of the cost reduction initiative including reduced payroll costs and benefit costs. He stated that this benefits customers by reducing the overall revenue requirement. He stated that the Company proposes to defer as a regulatory asset the \$30 million Indiana jurisdictional portion of the expense of the cost reduction initiative and amortize that amount over three years.

Mssrs. Krawec and Chodak explained that the cost reductions and the cost incurred to achieve these long term savings are both appropriately reflected in the proposed revenue requirement. On cross examination, Mr. Chodak explained that customers will receive \$7.4 million net savings per year in O&M costs as a result of the workforce reduction initiative and that such savings will increase after the end of the amortization period.

(b) <u>OUCC Case-in-Chief.</u> Mr. Eckert recommended that the Company not be permitted to recover the costs incurred in connection with the workforce and cost reduction initiative because they are non-recurring and, he contended, the Company will have already recovered its cost to implement the cost reduction initiative program through the employee expense-related savings it will recognize between the time the cost reduction initiative was implemented and the time new rates are established for Petitioner. Mr. Eckert recommended an adjustment of \$12,087,093 to the test year for I&M's portion of AEPSC's workforce cost reduction initiative expenses as opposed to Petitioner's adjustment of \$8,058,062, thus decreasing total company I&M expense by \$4,029,031 and Indiana jurisdictional expense by \$2,767,846. With respect to I&M's cost reduction initiative expenses, he recommended test year expense be adjusted by \$31,466,957 compared to Petitioner's adjustment of \$20,977,970, thereby decreasing total company I&M expense by \$10,488,987 and Indiana jurisdictional expense by \$7,317,820.

(c) <u>Industrial Group Case-in-Chief.</u> Mr. Selecky stated that he agreed with the Company's proposed adjustments from the test year O&M expense; but testified that it was inappropriate to include the amortization of those costs in the test year revenue requirement. Mr. Selecky explained that it was improper to include the amortization of the costs in the revenue requirement because I&M has already realized operating expense savings resulting from the employee reductions which occurred in 2010. As Mr. Selecky explained, this means that by the time new rates go into effect for I&M, it will have experienced reduced employee related O&M costs for an extended period. Mr. Selecky opined that it was inappropriate for I&M to seek reimbursement from ratepayers for all the costs associated with the severance and relocation program nearly two years after it began seeing reduced expenses as a result of the program as this will result in overcharging customers.

Mr. Selecky testified that based on his analysis, the cost reduction initiatives implemented by I&M have resulted in annual savings to the Company of approximately \$26 million and that these savings are currently being realized through reduced expense levels. Mr. Selecky explained that he developed the annual savings by relying on I&M's response to discovery requests which indicated that the Company had identified \$25.1 million in annual O&M and capital payroll cost savings as a result of the program. Applying the 75.76% O&M

factor used by I&M to make payroll adjustments to the $25.1 million in savings identified by I&M, this resulted in annual savings for the Company of $19.0 million. That figure, plus $7.1 million in savings I&M identified as its portion of AEP Service Company's workforce reduction, totaled the $26.1 million in savings Mr. Selecky identified.

Mr. Selecky testified that, assuming new rates go into effect for I&M as of January 1, 2013, the Company will have realized $52.2 million in savings. Mr. Selecky compared this figure to the $43.6 million in costs paid or allocated to I&M for the cost reduction initiative, which Mr. Selecky testified means that by the time new rates go into effect for I&M, it will have realized more in total expense savings than it expended in severance and relocation expenses. Mr. Selecky testified that since the Company will have saved more than the costs it incurred, the Company's proposal to amortize the $43.6 million over a three year period is unnecessary. Rather, Mr. Selecky testified, the total cost of the severance and relocation program should be removed from test year O&M, and no further recognition given to the expense. Accordingly, Mr. Selecky testified that I&M's O&M expense should be reduced by $14.518 million.

(d) SDI Case-in-Chief. Mr. Smith also opposed inclusion of the workforce cost reduction initiative costs in I&M's O&M expense, stating they were non-recurring. He further stated there is no need for a prospective amortization of those costs to determine a revenue requirement for I&M's Indiana jurisdictional operations for purposes of this case. He testified that any remaining costs have already been absorbed by related savings experienced by AEP through the approximate effective date of new permanent rates in this proceeding. As a result, Mr. Smith proposed removal of $7.112 million for I&M direct severance cost amortization and $2.732 million of severance cost amortization for AEPSC severance costs allocated to I&M's Indiana jurisdictional operations.

(e) I&M Rebuttal. Mr. Krawec offered rebuttal testimony in response to the proposed removal from the revenue requirement of the test year expenses associated with the cost reduction initiative. He stated that the simple fact that an expense is non-recurring does not mean it is not recoverable in either the test period cost of service or as an amortized regulatory asset. He explained that the severance program was part of an ongoing business practice of managing expenses to ensure both acceptable service and low rates for customers while ensuring I&M's future viability to attract the capital necessary to make prudent investments to serve its customers in the future. He testified that the Company and its customers will benefit from these initiatives for years to come and I&M should not be punished for making prudent cost beneficial decisions. He said the cost reduction initiatives have positioned I&M to operate more efficiently in this troubled economy, but it should not be assumed that the initiatives provided the Company with a financial windfall such that the net costs related to their implementation were recovered. He acknowledged that it is clear from I&M and the OUCC's pre-filed testimony in this case that there are already savings from the cost reduction initiative program that will be reflected in the rates in this proceeding.

(f) Commission Discussion and Findings. In 2010, I&M implemented a number of cost reduction initiatives, including employee reductions. The company now wishes to amortize the Indiana jurisdictional share of the roughly $30 million in costs incurred by the company as a result of the initiatives over a three year period. At the same time, the company has proposed to adjust the test year expense to reflect the cost savings associated with operating with a reduced workforce.

Both the OUCC and Industrial Group concur that I&M total company O&M expense should be reduced by a total of $14.518 million to reflect the cost savings realized through the initiatives. Accordingly, based on the testimony of Mr. Eckert, we reduce I&M's Indiana jurisdictional O&M expense by $10.086 million.

The question now before us is whether the company's O&M expense should be further adjusted, as requested by I&M, to account for the costs associated with the cost and workforce reduction initiatives. We decline to do so. In requesting recovery of the costs associated with the initiatives, I&M argues that because it has not "cumulatively over-earned" its authorized return since its last rate order, there is no evidence that the company's shareholders have realized a return of the company's investment in the initiatives. This misses the point. Whether or not the company has "cumulatively over-earned" is not the appropriate question in this context. Rather, the question that needs to be asked is whether I&M has already recouped the costs of the initiatives through lower O&M expense. The undisputed evidence is that it has. As Mr. Selecky testified, the company has identified through discovery a total of $26.1 million in annual savings associated with the initiatives. This means that, at the time of this order, the company will have a direct reduction in its O&M expense since 2010 of over $52 million. This is money that the company, in the absence of the initiatives, would have been required to spend as part of its O&M budget. These savings more than offset the $43.6 million ($30 million Indiana jurisdictional) in costs which the company incurred to implement the initiatives.

Having recovered the costs through directly related reduced expenses, it would be inappropriate to offset the reduction in O&M expense to reflect the amortized costs of the initiatives as doing so would permit I&M to recover those costs twice through rates, first through the O&M savings, and then through separate inclusion of the costs in revised rates. We will not authorize such double recovery.

(13) <u>Miscellaneous Tax Expenses.</u>

(a) <u>OUCC Case-in-Chief.</u>

(i) <u>Gross Revenue Conversion Factor.</u> Mr. Eckert proposed a Gross Revenue Conversion Factor of 166.5502% as opposed to 166.5520%, based on the current IURC Fee for 2011-2012. He used Petitioner's proposed state income tax rate and federal income tax rate in his calculation.

(ii) <u>IURC Fees.</u> Mr. Eckert proposed a different IURC fee expense adjustment than Petitioner to reflect (1) the 2011-2012 IURC fee of .1178510% instead of the 2010-2011 fee and (2) the OUCC's proposed revenue adjustments (as opposed to Petitioner's).

(iii) <u>Utility Receipts Tax.</u> Mr. Eckert also proposed a different Indiana Utility Receipts Tax adjustment to reflect the OUCC's proposed revenue adjustments.

(iv) <u>State and Federal Income Tax.</u> Finally, Mr. Eckert proposed pro forma present rate Federal and State Income Tax adjustments reflecting the OUCC's proposed differences in various revenue and expense items. He proposed an adjustment to pro forma State Income Tax expense of $6,502,531 and an adjustment to pro forma Federal Income Tax expense of $34,407,692.

(b) **I&M Rebuttal.** In its rebuttal exhibits I&M adjusted the IURC fee to reflected annualized March 2011 expenses; used the actual tax liability for the Utility Receipts tax based on the test period taxable receipts; updated the state and federal income tax calculations and reflected a gross conversion factor of 1.6655.

(c) **Commission Discussion and Findings.** To the extent that we have rejected most of the OUCC's proposed revenue and expense adjustments, we decline to adjust IURC fee expense, Utility Receipts Tax expense, and State and Federal Income Tax expense to reflect these proposed adjustments. We find that the foregoing fees and tax issues otherwise identified in the OUCC's filing are properly reflected on Petitioner's Exhibit SMK-R1 and Petitioner's Exhibit A-R5 and that these matters should be addressed in the revenue requirement as proposed in I&M's rebuttal filing.

10. **New Depreciation Rates.** I&M requested a change in its current depreciation rates. Ind. Code § 8-1-2-19 ("Section 19") authorizes the Commission to "ascertain and determine the proper and adequate rates of depreciation of the several classes of property of each public utility." Thus, the Legislature has recognized that proper depreciation rates are not stagnant – they need to be updated and revised to reflect current facts and circumstances.

A. **I&M Case-in-Chief.** David A. Davis, AEPSC Manager - Property Accounting Policy and Research, testified in support of revised depreciation accrual rates for I&M's electric plant in service and sponsored the depreciation study that he had conducted. He explained that the depreciation rates determined by the study are intended to provide recovery of invested capital, cost of removal, and credit for salvage over the expected life of the property. He said the revised depreciation rates are primarily required due to changes in investment, expected life and net salvage of I&M's property that takes into account recently proposed U.S. Environmental Protection Agency ("USEPA") national standards. As explained by Mr. Chodak, the revised depreciation rates will allow I&M's depreciation expense to more closely match the recovery of its investment with the period in which the plant provides service to customers. As also noted by Mr. Chodak, compliance with the federal mandate increases total depreciation expense by $3 million.

Mr. Davis presented a comparison of I&M's current depreciation rates and accruals and the depreciation rates and annual accruals reflected in the depreciation study. Based on results of the study and applying I&M Indiana rates to total Company plant in service, he recommended an increase in annual depreciation expense of $36,691,313 on a total Company basis using depreciable plant balances at December 31, 2010.

The methods and procedures used were fully described in the depreciation study and summarized in Mr. Davis' testimony. As Mr. Davis explained, all of the property included in the depreciation report was considered on a group plan. Under the group plan, depreciation is accrued upon the basis of the original cost of all property included in each depreciable plant group instead of individual items of property. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accumulated provision for depreciation regardless of the age of the particular item retired. Also under this plan, the dollars in each primary plant account are considered as a separate group for depreciation accounting purposes and an annual depreciation rate for each account is determined. As discussed by Mr. Davis, in the I&M study, the plant groups consisted of the individual primary plant accounts for Production, Transmission, Distribution and General Plant property. The depreciation rates were calculated by the Average Remaining Life Method, which is the same method that was used to calculate I&M's current depreciation rates. The Remaining Life method recovers the original cost of the plant, adjusted for net salvage, less accumulated depreciation over the average remaining life of the plant.

As Mr. Davis explained, for Production Plant, the generating unit retirement dates and the interim retirement history for the individual plant accounts were used to determine the average service lives and the remaining lives of the plants. He said the average service lives for the Company's Transmission, Distribution and General Plant were determined using statistical procedures similar to those used in the insurance industry in studies of human mortality. The historical retirement experience of property groups was studied and retirement characteristics of the property were described using the Iowa-type retirement dispersion curves. Net salvage for each property group was determined based on actual historical experience for Production, Transmission, Distribution, and General Plant accounts. In addition Production Plant included terminal retirement net salvage amounts for Steam Production Plant. Mr. Davis explained that to determine these amounts, I&M commissioned the independent engineering firm, Sargent & Lundy ("S&L"), to update their conceptual dismantling cost estimates that are included in I&M's current depreciation rates for the Tanners Creek and Rockport Plants. He said the recommended depreciation rates for Production Plant included the dismantling cost for Tanners Creek and Rockport Plants at their estimated retirement dates.

Mr. Davis clarified that S&L provided terminal net salvage amounts excluding any asbestos, ash pond or landfill type removal costs that were stated at a 2010 price level. He applied a 2.5% inflation rate factor to the net salvage amounts provided by the S&L study to determine the terminal net salvage amount at each plant's retirement year. He said the terminal net salvage amount after inflation was used in the calculation of net salvage percentages in the depreciation study. Mr. Davis explained that the 2.5% inflation rate was taken from a publication titled "The Livingston Survey" dated December 9, 2010. The Livingston Survey is published by the research department of the Federal Reserve Bank of Philadelphia and provides a long term inflation outlook projecting an inflation rate for a 10 year period.

Mr. Davis explained that the cost to remove asbestos and to cover ash ponds and landfills were excluded from the S&L steam plant dismantling study because these amounts are included in the Company's accounting for asset retirement obligations ("ARO") and the depreciation and accretion on these AROs are incorporated in cost of service outside of the depreciation study.

Mr. Davis explained that he calculated separate depreciation rates for the Tanners Creek Selective Non-Catalytic Reduction ("SNCR") Project and Rockport's Activate Carbon Injection ("ACI") System because the depreciable life for these systems was established and approved by the Commission in Cause No. 43636. He noted that the depreciation rates for this equipment have been updated to reflect current estimated remaining lives.

Mr. Davis stated that based on the depreciation study, the composite depreciation rate for Steam Production Plant increased from 1.85% to 3.05% primarily due to a 6 year shorter life estimate for Tanners Creek Units 1-3 and an increase in Rockport and Tanners Creek plant investment since the prior depreciation study. Mr. Davis and John F. Torpey, AEPSC Director-Integrated Resource Planning, explained that the estimated life for Tanners Creek Plant Units 1-3 was shortened due to the Company's response to recently proposed USEPA national standards. These witnesses explained that neither Tanners Creek Unit 4 nor Rockport's estimated retirement dates changed from the prior depreciation study.

Mr. Davis testified that the composite rate for Cook Nuclear Plant increased from 1.16% to 1.74% mainly due to a $401 million increase in Cook's electric plant in service and a shorter estimated remaining life since the last depreciation study. He noted that the Cook Plant's estimated retirement dates did not change from the prior depreciation study.

Mr. Davis stated that the composite rate for Hydraulic Production Plant increased from 1.44% to 2.27% due to a $2.7 million increase in Hydraulic Plant electric plant in service and a shorter estimated remaining life since the last depreciation study.

Mr. Davis testified that the depreciation rate for Transmission Plant increased from 1.46% to 1.68% due to increases in the net salvage ratio for six accounts (accounts 352, 353, 354, 355, 356 and 358) which was partially offset by an increase in average service life for four accounts (accounts 353, 354, 355 and 358). He stated that an analysis of the $2,614,244 annual Transmission depreciation expense increase indicates that the net salvage ratio increase (1 minus the net salvage percentage) accounted for $3,960,132 of the increase and that other changes including the increase in average service life estimates for four accounts caused a $1,345,888 decrease.

Mr. Davis stated that the depreciation rate for Distribution Plant increased from 2.44% to 2.84% due to increases in the net salvage ratio for eight accounts (accounts 361, 362, 364, 365, 368, 369, 370 and 373) and a decrease in the average service life for one account (account 370). The rate increase was partially offset by an increase in average service life for six accounts (accounts 362, 365, 367, 369, 371 and 373). An analysis of the $5,505,034 annual Distribution depreciation expense increase indicates that the net salvage ratio increase accounted for $4,411,256 of the depreciation expense increase and other changes amounted to a $1,093,778 increase.

Mr. Davis testified that the depreciation rate for General Plant increased from 2.41% to 3.00% due to increases in the net salvage ratio for five accounts (accounts 390, 391, 394, 397 and 398). He explained that an analysis of the $479,756 annual General Plant depreciation expense increase shows that the net salvage ratio increase accounted for $488,826 of the depreciation expense increase and other changes amounted to a $9,070 decrease.

B. <u>OUCC Case-in-Chief.</u> Mr. Dunkel responded to Mr. Davis's testimony and the depreciation study. Mr. Dunkel's recommended depreciation rates were presented in Attachment

WWD-1. He recommended an increase in annual depreciation expense of $16.3 million on a total Company basis using depreciable plant balances at December 31, 2010, which is $20.4 million less than the annual increase proposed by I&M.

In calculating his proposed depreciation rates, Mr. Dunkel used June 2015 as the expected retirement date for Tanners Creek Units 1-3, based on his testimony that the PJM web site indicates that I&M has requested "6/1/2015" as the "Deactivation Date" of those units.

Mr. Dunkel's proposed depreciation rates excluded the retirements, gross salvage, and cost of removal amounts associated with the Cook Unit 1 turbine replacement.

Mr. Dunkel recommended adjusting the "Conceptual Demolition Cost Estimates" for Tanners Creek and Rockport Unit 1 based on the actual costs incurred to date to demolish I&M's Breed Plant. He argued that the Conceptual Cost Estimates provided by I&M for the Rockport Unit 1 and Tanners Creek units are not representative of the actual cost to demolish a steam production plant because the actual cost to demolish the Breed Plant was less than the Conceptual Cost Estimate for the Breed Plant demolition.

Mr. Dunkel recommended not inflating demolition costs to 2044 (for Rockport 1) or 2030 (for Tanners Creek Unit 4) price levels.

Mr. Dunkel recommended removing the Breed Plant terminal removal costs and terminal salvages from the "interim" net salvage analysis prior to calculating the steam production depreciation rates to avoid double recovering the Breed terminal removal costs. He also recommended discontinuing the interim retirements of Tanners Creek Units 1-3 after their retirement since the annual dollar amount of the interim retirements will decrease after Units 1-3 are no longer in service and therefore no longer creating interim retirements. Mr. Dunkel's calculations reflected the fact that most common facilities (in addition to Unit 4) will still be in service after Tanners Creek Units 1-3 are retired.

Mr. Dunkel contended that an inconsistency between the gross salvage and cost of removal amounts reflected in I&M's depreciation study and the data reflected in I&M's FERC Form 1 casts doubt on the reliability of the salvage data used in Mr. Davis' depreciation study. Mr. Dunkel also raised a concern that a label on one of Mr. Davis' workpapers suggested that only cash salvage, instead of all gross salvage was reflected in Mr. Davis' depreciation study. Based on these two concerns, Mr. Dunkel recommended that the net salvage factors reflected in the depreciation rates approved in the Commission's June 13, 2007 Order in Cause No. 43231 continue to be used.

C. <u>Industrial Group Case-in-Chief.</u> Mr. Selecky recommended that I&M's proposed depreciation rates be reduced to exclude the effects of including a contingency factor in the demolition cost estimates. He testified that the contingency factor does not represent a true cost and therefore should be excluded from the decommissioning cost estimates. Mr. Selecky urged the Commission to give weight to the potential value of the steam production sites and utilize that value to eliminate the proposed contingency factors.

Mr. Selecky recommended that the final decommissioning escalation rate used in the decommissioning cost estimates be reduced from the proposed 2.5% to 2.2%. He stated that the

2.2% rate was based on more current information from the U.S. Energy Information Administration's Annual Energy Outlook 2012 Early Release Overview Consumers Price Index for the period 2010-2035.

He recommended that the life of Tanners Creek Units 1, 2 and 3 be extended by two years and that the life span of Rockport Unit 1 be increased from 60 to 65 years for purposes of calculating the depreciation rates.

Mr. Selecky's proposed revisions to I&M's depreciation parameters (life span and final net salvage ratios) would reduce the proposed depreciation expense by $7.794 million.

D. I&M Rebuttal. Steven R. Bertheau, Senior Vice President and Project Director with S&L, refuted Mr. Selecky's recommendation to exclude contingency factors associated with the scrap value, material, labor and indirect costs in the demolition conceptual cost estimates. Mr. Bertheau explained that the S&L demolition cost estimates for the Rockport and Tanners Creek plants were developed through site-specific analysis (and the opposing recommendations were not). He explained that the cost estimates were prepared consistent with prudent industry practices and previous S&L demolition estimates. He added that S&L's experience with demolishing parts of existing facilities to modify plant configurations for accommodating new equipment also provided a basis for the estimating procedures used to prepare the demolition cost estimate studies for I&M.

Mr. Bertheau testified that there are numerous reasons why it is appropriate to include contingency factors. He said one reason is that power plants are in a continuous state of configuration change over their operating lives. Improvements in technology, changes in plant operating approach, and degradation of plant equipment cause power plant configurations to evolve over the life of the facility. He stated that a demolition study, however, must be made at a certain point in time at which it is not possible to anticipate with precision all the ways the plant will be modified over time as a result of this dynamic. He explained that in addition, significant changes to power plant configurations over the life of the plant are associated with changing environmental regulatory requirements. He stated that the change in and issuance of final and proposed environmental regulations have and will result in billions of dollars in increased infrastructure and new buildings and equipment being added to power plants in order to control emissions. As future environmental rules are implemented, additional infrastructure, buildings, and equipment will be retrofitted into existing facilities. Mr. Bertheau explained that since the nature and scope of future plant configuration changes are not clearly defined at this time, positive contingencies in demolition cost estimates are necessary to account for the increases in plant facilities that will occur between the time that the cost estimates were developed and the end of life of the facility. He added that contingencies capture unknowns and future changes, and are a common industry standard practice. He testified that the contingencies used in the demolition estimates in this case are reasonable and similar to the factors approved by the Commission in Northern Indiana Public Service Company ("NIPSCO") Cause No. 43526, wherein the Commission rejected similar arguments from Mr. Selecky made with respect to NIPSCO's studies.

Mr. Bertheau responded to Mr. Dunkel's recommendation that the S&L demolition cost estimates for Tanners Creek and Rockport Unit 1 should be adjusted based on the actual cost data from the Breed facility demolition. Mr. Bertheau stated that Mr. Dunkel's logic in making such a recommendation is flawed in assuming that Breed's demolition can be compared to both Tanners Creek and Rockport. Mr. Bertheau explained that power plants each have unique facility configurations and therefore costs for demolition can vary greatly between facilities. He stated the Rockport and Tanners Creek demolition cost estimates were developed as site specific and cannot be arbitrarily adjusted based on the cost of demolition of a completely different plant. He explained that the S&L study substantiates the site-specific demolition, excavation, and disposal characteristics of each I&M site and testified that each facility was evaluated on an individual basis, due to inherent differences, to ensure that prudent and reasonable cost estimates were provided for the most-likely demolition scenario. He testified that the assumptions used to prepare the demolition cost estimates were consistent with prudent industry practices and previous S&L demolition estimates. S&L's experience with demolishing parts of existing facilities to modify plant configurations for accommodating new equipment also provided a basis for the estimating procedures used to prepare the demolition cost estimate studies for I&M.

He testified that the demolition techniques and crew mixes assumed in the S&L cost estimates are efficient, cost effective and are typical techniques used in the industry based on S&L's 120 plus years of experience exclusively serving the electrical power generation industry and also reflected input from a major demolition contractor, U.S. Dismantlement. He stated that the techniques and approaches for demolition reflected in the study are based on the experiences of individuals who have competitively bid and successfully executed the subject work for many years. Mr. Bertheau testified that controlled demolition techniques were specified in the study at locations where critical infrastructure would be at risk of serious damage by use of uncontrolled demolition. He stated that it would be irresponsible to destroy viable and costly infrastructure in an attempt to save a nominal amount of money via use of an uncontrolled demolition technique. He noted that the permitting, execution and clean-up costs for using uncontrolled demolition at certain sites would be significant and carry significant risk. Mr. Bertheau testified that the controlled demolition techniques assumed in the S&L cost estimates are proven in the industry which will protect critical infrastructure and maintain its viability for future use.

Mr. Davis disagreed with Mr. Selecky's recommendation to reduce the decommissioning cost escalation rate from 2.5% to 2.2%. Mr. Davis explained that Mr. Selecky's logic for changing the inflation percentage is that the Commission should use more current information than that published in the Livingston Survey dated December 9, 2010. Mr. Davis stated that the updated Livingston Survey dated December 8, 2011 continues to use the 2.5% inflation factor published in the 2010 survey. In addition, Mr. Davis identified several other current measures of inflation that were higher than 2.5% and therefore support I&M's use of a 2.5% inflation factor as conservative and reasonable. He also noted that Mr. Selecky's recommended escalation rate of 2.2% is inconsistent with Mr. Selecky's own recommendations in Cause No. 43526 involving NIPSCO, in which he indicated that NIPSCO should use a 2.5% inflation factor instead of NIPSCO's recommended 3%.

Mr. Davis disagreed with Mr. Selecky's recommendation that the Commission give recognition to the potential value of the steam production sites and utilize that value to eliminate the proposed contingency factors. He stated that Company-owned land that may or may not be used for a future generating site is non-depreciable property and as such should never be considered in a depreciation study. He stated that I&M has no current plans to re-use the existing generating sites so the future benefit is speculative. Any existing structures that remain on the generating plant site and continue to be used and useful would be on the Company's books at original cost less accumulated depreciation and included in rate base. Mr. Davis noted that in Cause No. 43526 (IURC 8/25/2010), the Commission rejected Mr. Selecky's proposal to treat a non-depreciable asset like land as salvage.

Mr. Torpey explained in his rebuttal testimony that I&M's proposed retirement date for Tanners Creek Units 1-3 is primarily based on the cost to comply with the Mercury and Air Toxics Standards ("MATS") Rule which was finalized after I&M's case in chief was filed in this Cause, and, to a lesser extent, the proposed Coal Combustion Residual ("CCR") regulations expected to be finalized in 2013. Mr. Torpey argued that Mr. Selecky's suggestion that the MATS Rule may be reversed should not influence the proposed retirement date for the Tanners Creek Units 1-3. He explained that Mr. Selecky's belief that the implementation of these rules might be delayed has no foundation. However, given that the MATS Rule became effective later than the date estimated in Mr. Torpey's direct testimony, I&M agreed that the proposed retirement of June 1, 2015 should be adopted for planning purposes. However, Mr. Davis observed that the change in the planned retirement date would not make a material difference in the depreciation rates. Mr. Davis explained that the new depreciation rates are based on a December 31, 2010 study and the recommended rates would not be effective until late in 2012. As a result there will be a lag in implementing new depreciation rates of more than 1 and ½ years from the date of the depreciation study and the lag would more than compensate for Mr. Dunkel's proposed June 2015 retirement date. Therefore, Mr. Davis asserted that I&M's depreciation rate calculation for Tanners Creek Units 1-3 should not be adjusted for a June 2015 retirement date.

Mr. Torpey disagreed with Mr. Selecky's recommendation to extend the useful life of Rockport Unit 1 from 60 years to 65 years. He explained that the remaining service life of a power generating facility is generally correlated to the level of maintenance and routine component replacement that is undertaken through the life of the unit. Accordingly, contrary to Mr. Selecky's suggestion, Mr. Torpey stated there is no relationship between the remaining service lives of Rockport Unit 1 and Tanners Creek Unit 4 or the coal plants listed on Industrial Group Exhibit JTS-2 to Mr. Selecky's testimony. Mr. Torpey noted that Mr. Selecky did not present an assessment of the condition or operating characteristics of Rockport Unit 1 that would lead to a conclusion that a longer life is warranted.

Mr. Davis agreed that an adjustment should be made to eliminate the retirements and cost of removal along with the salvage (which was already eliminated from the Company's analysis) related to the Cook Unit 1 turbine replacement. However, Mr. Davis noted an error in Mr. Dunkel's calculation and presented the corrected calculation.

Mr. Davis disagreed with Mr. Dunkel's assertion that the conceptual demolition study amounts for Tanners Creek Units 1-3 and Rockport Unit 1 should not be adjusted for inflation. He explained that Mr. Dunkel's use of "current day values" for salvage and removal is incompatible with the purpose of depreciation which requires depreciation over the useful life of assets in a systematic and rational manner. He stated the regulatory rationale for setting depreciation rates on a straight line basis over the remaining life of the property is to promote intergenerational equity and appropriately match cost to the provision of service. Mr. Davis cited prior Commission orders where the Commission has accepted the calculation of terminal demolition costs inflated to their retirement date, including the May 18, 2004 Order in Cause No. 42359 and the August 25, 2010 Order in Cause No. 43526. In addition, Mr. Davis testified that I&M escalated terminal demolition costs for its steam generating stations in Cause No. 39314. He noted that in Cause No. 42959, in which I&M's current depreciation rates were established, I&M chose not to escalate the terminal demolition costs, but did so to "eliminate most areas of controversy to facilitate a more expedient decision from the Commission." Mr. Davis stated that I&M's inflation of the S&L terminal demolition estimates implements a cost-based approach because the future estimate of terminal demolition costs more precisely determines the total net cost of demolishing the plants.

Interim net salvage relates to retirement costs for property that is retired prior to the final terminal retirement of the property. Mr. Davis explained that it is important to include an analysis of interim retirements in a depreciation study since all of the property that is initially placed in service will not last until the final retirement date. Mr. Davis stated that some terminal (final) demolition costs should be excluded from the interim net salvage calculation but explained that Mr. Dunkel's adjustment is incomplete because the calculation included salvage and removal costs related to the Breed generating station and ignores the Twin Branch Steam Plant's original cost retirement in 1981. Mr. Davis explained that when the proper adjustment is made the net salvage percentage equals the percentage calculated in the Company's depreciation study. Hence no adjustment is necessary.

Mr. Davis agreed that the calculation of depreciation rates for Tanners Creek Units 1-3 should be adjusted to reduce interim retirement amounts after the terminal retirement of Tanners Creek Units 1-3 and set forth this revision on Petitioner's Exhibit DAD-R6.

Mr. Davis disagreed with Mr. Dunkel's proposal to decrease the steam production rates to account for common plant which will remain on the Company's books until Unit 4 retires. He explained that I&M does not maintain a property record for Tanners Creek Plant by unit, so an estimated retirement amount was calculated for Units 1-3 based on an allocation using megawatt capacity. He stated that neither Mr. Dunkel nor the Company has gathered adequate information to calculate or determine if a significant amount of common plant should be deducted from the estimated retirement of Units 1-3 to calculate depreciation rates and therefore Mr. Dunkel's adjustment is unwarranted and lacks adequate support. Mr. Davis explained that when the Tanners Creek Units 1-3 are retired, the Company will perform a detailed study to determine the proper amount of original cost to retire and any over or under accrual of depreciation will be reflected in future depreciation rates by using the remaining life technique.

Mr. Davis disagreed with Mr. Dunkel's proposal not to update the net salvage factors used for Transmission, Distribution and General Plant. Mr. Davis explained that I&M's depreciation study used the same procedures and techniques to gather and report salvage and removal amounts and calculate percentages for Transmission, Distribution and General Plant as was used in its filing in Cause No. 42959, which Mr. Dunkel did not oppose in that Cause. Mr. Davis explained that he did not use the same salvage data amounts as presented on the Company's FERC Form 1 because the FERC Form 1 amounts include retirement work in progress amounts ("RWIP"), which should never be included in depreciation study calculations. Mr. Davis explained that RWIP is accumulated on work orders similar to construction work in progress. He stated that while the removal work is being performed, RWIP charges and salvage amounts continue to be accumulated until the work is done and the work order is closed. He explained that when the work order is closed, an original cost retirement is recorded and only then is it possible to match retirements, salvage and removal in the depreciation study. Mr. Davis explained that it would be incorrect to include RWIP in the depreciation study because this would require salvage and removal to be divided by as yet to be booked original cost retirements. Said another way, including the salvage and removal without the original cost retirement would be including the numerator without the denominator (dividing by zero). Mr. Davis disagreed with Mr. Dunkel's discussion of the FERC Form 1 data and explained that the amounts in I&M's depreciation study and the FERC Form 1 data both come from the financial records of the Company that are reviewed by I&M and AEP management and external auditor Deloitte & Touche. Mr. Davis explained that the depreciation study amounts were gathered in a consistent fashion with prior depreciation studies. Mr. Davis explained that Mr. Dunkel's calculation is in error because it relied on a data request response that reflected RWIP transferred to in service instead of the data request response that provided the full RWIP balance. Mr. Davis presented a reconciliation of the amounts of retirements, salvage and removal reported in the FERC Form 1.

Mr. Davis also disagreed with Mr. Dunkel's contention that the net salvage calculations should be tossed aside as unreliable due to a label in one of Mr. Davis' workpapers. He stated that I&M did not exclude non-cash salvage from the depreciation study. He explained that the reference to "Salvage Cash" in the workpapers was merely an incorrect label. He explained that this issue had been explained to the OUCC in the discovery process. He clarified that the "Salvage Cash" amount was not just cash salvage but included in the total amount of salvage booked for the period of time in question.

Because of his concerns about the data used to calculate net salvage, Mr. Dunkel recommended that the Commission continue to use the net salvage factors for Transmission, Distribution and General Plant from Cause No. 43231 in lieu of the factors calculated in the current depreciation study. Mr. Davis disagreed. Mr. Davis explained how the net salvage percentages provided in the depreciation study were calculated, utilizing estimated net salvage values for Transmission, Distribution and General Plant based on historical net salvage costs as a percent of the original cost of the retired assets that produced the gross salvage or required costs to remove the property. He defended the reliability of the salvage and removal data used in the depreciation study. He also presented an updated net salvage factor calculation adding year 2011. He added that only two net salvage factors were less negative (accounts 355 and 362) and eleven factors slightly more negative as a result of that update.

E. <u>Commission Discussion and Findings.</u> I&M's present depreciation rates for its electric utility plant are based on a 2004 depreciation study accepted in a settlement agreement in Cause No. 43231 which was approved on an interim basis in Cause No. 43231 and which was finalized in Cause No. 43306. The existing depreciation rates for Rockport's ACI system and Tanners Creek's SNCR were established in 2009 under Cause No. 43636 related to the use of clean coal technology. We discuss the disputed issues regarding I&M's proposed depreciation rates below.

(1) <u>Escalation Rate.</u> Mr. Selecky objected to the rate of inflation assumed for steam production plant, whereas Mr. Dunkel disagreed with the use of inflation adjusted terminal cost of removal amounts and instead recommended the use of "current day values" for salvage and removal. We have previously accepted the calculation of terminal demolition costs inflated to their retirement date. We note that I&M escalated terminal demolition costs for its steam generating stations in Cause No. 39314 (using a 4% escalation rate). Therefore, we find that inflation should be factored into dismantlement cost estimates and reject the OUCC's proposal to restate costs of removal at present value.

Based upon projections of future inflation set forth in the Annual Energy Outlook 2012 Early Release Overview, Mr. Selecky reduced Mr. Davis' recommended depreciation accrual rates by assuming that future inflation will be lower than historical inflation. Mr. Selecky has failed to demonstrate any reason to believe his estimate of future inflation is a more reliable predictor of future inflation than the estimates shown by Mr. Davis to be consistent with current and reliable sources. In fact, Mr. Selecky himself has previously recommended, in Cause No. 43526, the same 2.5% inflation rate used by I&M in this case. We therefore reject Mr. Selecky's proposal to modify the depreciation rates using lower estimates of future inflation.

(2) Demolition Conceptual Cost Estimates.

(a) Contingency Factor and Non-Depreciable Land. The next issue to be resolved is the use of a contingency factor in determining the final terminal salvage estimates. Mr. Selecky argued that the contingency should be eliminated as a trade-off for the value of the steam production sites. Mr. Davis explained that Company-owned land that may or may not be used for a future generating site is non-depreciable property and as such should never be considered in a depreciation study. He stated that I&M has no current plans to re-use the existing generating sites so the future benefit is speculative. In our decision in Cause No. 43526, issued August 25, 2010, we rejected a similar proposal made by Mr. Selecky with respect to NIPSCO's studies. Here, as in Cause No. 43526, Mr. Selecky did not identify a dollar value associated with the value of land and as a result there is no evidence in the record to guide us in determining whether this would produce a material difference in the depreciation rates or be a reasonable trade-off for the contingency, assuming for the sake of argument it would even be proper to treat a non-depreciable asset like land as salvage. In our Order in Cause No. 43526, we found that "[n]o evidence was presented that this Commission has ever used the value of land as an offset to an asset's cost of removal. In fact, Mr. Selecky did not identify to us any decision of any regulatory commission accepting his position regarding land and the contingency." Once again, Mr. Selecky has failed to provide evidence sufficient to support his proposal and, once again, we reject his proposal. We find the contingencies used in I&M's demolition estimates to be reasonable and similar to the factors we approved in Cause No. 43526.

(b) Revisions Based On Breed Plant Actual Demolition Cost. Mr. Dunkel asserted that the demolition conceptual cost estimates conducted by S&L should be adjusted based on the Breed Plant actual demolition cost. Mr. Dunkel then used an adjustment factor of 0.40 and applied it to site-specific cost estimates for Tanners Creek and Rockport. The record reflects that power plants each have unique facility configurations and therefore costs for demolition can vary greatly between facilities. The S&L study reflects the use of controlled demolition techniques at locations where critical infrastructure would be at risk of serious damage by use of uncontrolled demolition.

The evidence of record shows that S&L is well-qualified with specific expertise in producing demolition cost estimate studies and that the S&L demolition cost estimates are clearly substantiated and based on site specific data, assumptions consistent with prudent industry practices and previous S&L demolition estimates. This Commission has long accepted and relied on site specific S&L demolition cost studies for purposes of establishing depreciation rates.

The record also reflects that Breed was a stand-alone unit in a relatively uninhabited area and the dismantlement technique proposed for Breed may not be feasible for the Rockport and Tanners Creek plants which are not similarly situated. Further, Mr. Dunkel's contention that the actual costs to demolish the Breed Plant are less than the estimated costs is based on incomplete information because the full scope of the Breed demolition work has not been performed and will need to be completed for any potential future site development. We find that it is not appropriate to use the actual cost data from the Breed Plant demolition to estimate costs for demolition of distinct facilities with unique configurations. Accordingly, we further find that Mr. Dunkel's proposal to adjust the Tanners Creek and Rockport demolition cost estimates based on cost data for the Breed Plant demolition must be rejected.

(3) <u>Estimated Service Lives.</u>

(a) <u>Tanners Creek.</u> Petitioner and the OUCC accept June 2015 as the appropriate retirement date for Tanners Creek Units 1, 2 and 3. Industrial Group provided testimony from Mr. Selecky recommending a retirement date of December 31, 2016. Both Petitioner and the OUCC have provided testimony explaining that the retirement date is primarily driven by certain EPA regulations that have either recently become effective or are currently pending. These include: the Mercury and Air Toxics Standards ("MATS") Rule which became effective on April 16, 2012; the Cross State Air Pollution Rule ("CSAPR"); and the Coal Combustion Residual ("CCR") regulations requiring modifications to certain ash handling systems and ash ponds by 2018, which are still scheduled to be finalized in early 2013. Although CSAPR has been remanded on appeal, I&M is still required to comply with the MATS and CCR regulations. We find it is appropriate to establish a retirement date based on the existing or proposed rules. We find Mr. Selecky's proposed extension of the Tanners Creek Units 1, 2, and 3 service lives should be rejected. Although I&M and the OUCC agree that the planned retirement for these units has shifted slightly, we find it unnecessary to revise the new depreciation rates. The record reflects that the new depreciation rates are based on a December 31, 2010 study. Because the new rates will not be placed into effect until well after the date of the depreciation study, the timing difference will more than make up for the slight change in the retirement date for Tanners Creek Units 1-3. Accordingly, we find it is not necessary to adjust the new depreciation rates to reflect this change.

(b) <u>Rockport Unit 1.</u> Mr. Selecky recommends extending the useful life of Rockport Unit 1 from 60 years to 65 years, based on I&M's use of a depreciable life of 66 years for Tanners Creek Unit 4 and the depreciable lives of various other coal plants, many of which exceed 60 years. However, Mr. Selecky has failed to show a direct relationship between Tanners Creek Unit 4 or any of the other coal-fired units referred to in his exhibit and Rockport Unit 1 sufficient to show that the life spans of those other units are directly applicable to Rockport Unit 1. The service life of a power generating unit can vary depending on the plant owner's determination, at times when a significant investment is required to maintain a unit's operation, as to whether the least cost long-term solution is to repair/modify or retire/replace the asset. Those decisions must take into account both existing as well as projected future operating conditions and constraints. A plant owner can only make decisions based on the best available information at the time. While Mr. Selecky suggests it is possible that the Rockport Unit 1 will have a service life that exceeds 60 years, it is equally plausible that the service life will be less than 60 years, especially when developing EPA regulations regarding carbon emissions are taken into account. Our goal is to depreciate Rockport Unit 1 over its service life, not to artificially reduce rates in the short-term by pushing costs onto future generations. We cannot rely on mere possibilities. Here, the record does not reflect evidence of a condition or operating characteristics of Rockport Unit 1 that would reasonably lead to a conclusion that a longer life for the Rockport Unit 1 is warranted. Accordingly, we find no basis for proposing today to revise the remaining service life of this coal plant from 32 years to 37 years given the uncertainty around potential future environmental requirements. Therefore, we reject Mr. Selecky's proposal to modify the depreciable life of Rockport Unit 1 and accept the service life for this unit reflected in I&M's depreciation study.

(4) <u>Net Salvage Factors.</u> Petitioner and the OUCC disagree regarding the net salvage factors to be used by Petitioner's depreciation study for Transmission, Distribution and General Plant. Mr. Dunkel contends that the gross salvage and cost of removal amounts used in Petitioner's depreciation study are unreliable because he believes they are inconsistent with the information in I&M's FERC Form 1. Based on this belief, Mr. Dunkel recommended that we continue to use the net salvage factors reflected in rates previously approved in Cause No. 43231 in lieu of the factors calculated in the current depreciation study. Because the existing net salvage factors are based on a 2004 depreciation study, acceptance of this proposal would have the effect of pushing costs onto future generations. We decline to do this based on speculative concern raised by Mr. Dunkel, which rests on the flawed and unsupported premise that the Company's audited books and records (which Mr. Dunkel has not reviewed) and the sworn testimony of Mr. Davis are untrustworthy. Mr. Dunkel has failed to show that I&M's salvage data should be rejected. The data in I&M's depreciation study came from the Company's audited books and records which are presumed to be correct. Mr. Dunkel did not review I&M's books and records.

Mr. Davis has explained the difference between the data contained in the depreciation study and I&M's FERC Form 1 to our satisfaction. The difference relates to the fact that the FERC Form 1 reported data reflects RWIP. While Mr. Dunkel agreed that RWIP should not be included in a depreciation study, his analysis excluded the wrong amount for RWIP. He used the amounts identified as being transferred to in service. In doing so he captured the annual out-going activity in the RWIP account, not the complete balance in the RWIP account. The record reflects that I&M provided the complete RWIP balance included in the FERC Form 1 salvage and removal amounts in a response to an OUCC data request, but Mr. Dunkel's testimony did no address it. Further, Mr. Davis' explanation is supported by the Company's data request responses and the FERC Form 1 itself.

Additionally, a comparison of the FERC Form 1 data to that reflected in Mr. Davis' depreciation study shows that Mr. Davis' recommended increase in depreciation cost to capture the cost of removal net of salvage is reasonable. Petitioner's Exhibit DAD-1, p. 25 (col. III) shows total depreciable plant is $6,166,492,321. Column V of this exhibit shows the "Total To

Be Recovered" is $6,667,557,081. The difference between the Total Depreciable Plant and the Total To Be Recovered reflects the Cost of Removal (net of salvage). When one amount is divided by the other, the difference shows that cost to be recovered is increased 8% over the original cost in I&M's depreciation study to capture the cost of removal net of salvage. If the amounts reflected on the FERC Form 1 are used instead (cost of removal net of salvage on a percentage basis), the net salvage percentage for the years 2005-2010 is a negative 11.10%. This means that if the FERC Form 1 salvage and removal dollars were used as Mr. Dunkel urges, the cost to be recovered would need to increase by 11% to capture the cost of removal net of salvage. Because the FERC Form 1 increase in cost to be recovered is greater than the 8% increase reflected in Mr. Davis' study, we find the depreciation increase reflected in Mr. Davis' study to be conservative and reasonable.

Petitioner has also provided substantial evidence to show that Mr. Dunkel is incorrect in his statement that only "cash" salvage was used in Petitioner's depreciation study for Transmission, Distribution and General property. The record demonstrates the study included both cash and non-cash salvage. The evidence in the record shows that I&M's current depreciation study used the same procedures and techniques to gather and report salvage and removal amounts and to calculate these percentages as was used in its filing in Cause No. 42959. No revisions to these depreciation rates were proposed by Mr. Dunkel in that Cause, in which the depreciation rates decreased. We find that the depreciation study gross salvage and cost of removal amounts were gathered in a consistent fashion with prior depreciation studies and we accept those amounts. Accordingly, we accept Petitioner's recommended net salvage factors for Transmission, Distribution and General property.

Petitioner and the OUCC agree that the Company's calculation of interim net salvage should exclude terminal demolition costs. The record shows that if terminal demolition costs for Breed and Twin Branch steam plants are both removed from the depreciation study interim retirement analysis, there is no change in the net salvage factor. Accordingly, we find no adjustment is necessary.

(5) <u>Reduction to Retirement Amounts for Tanners Creek Units 1-3 for Common Plant.</u> Mr. Dunkel proposed to revise I&M's steam production rates by decreasing the estimated amount to be retired for Tanners Creek Units 1-3 to account for common plant which will remain on the Company's books until Unit 4 retires. We find there is inadequate support in the record for this adjustment and therefore reject it.

(6) <u>Exclusion of Salvage, Cost of Removal and Retirements for Cook Unit 1 Turbine Replacement.</u> The record reflects that the parties agree that the salvage, cost of removal and retirements associated with the Cook Unit 1 turbine replacement should be excluded. In his rebuttal testimony Mr. Davis presented a corrected calculation on Petitioner's Exhibit DAD-R3 which we find should be accepted.

(7) <u>Terminal Demolition Costs in Interim Net Salvage Factor.</u> Interim net salvage relates to retirement costs for property that is retired prior to the final terminal retirement of the property. It is important to include an analysis of interim retirements in a depreciation study since all of the property that is initially placed in service will not last until the final retirement date. Mr. Davis stated that some terminal (final) demolition costs should be excluded from the interim net salvage calculation, but explained that Mr. Dunkel's adjustment is incomplete because the calculation included salvage and removal costs related to the Breed generating station and ignores the Twin Branch Steam Plant's original cost retirement in 1981. The record reflects that when the proper adjustment is made the net salvage percentage equals the percentage calculated in the Company's depreciation study. Accordingly, we find that it is not necessary to adjust the depreciation study for this issue.

(8) **Interim Retirement Revisions Related to Tanners Creek Units 1-3 Retirement.** Mr. Davis agreed that the calculation of depreciation rates for Tanners Creek Units 1-3 should be adjusted to reduce interim retirement amounts after the terminal retirement of Tanners Creek Units 1-3 and set forth the revisions on Petitioner's Exhibit DAD-R6. We find this adjustment should be accepted.

(9) **Ultimate Finding.** We find that I&M's proposed depreciation rate changes as presented in Mr. Davis' Exhibit DAD-1 with revisions reflected in Rebuttal Exhibits DAD-R3 and DAD-R6 are reasonable, will provide the Company with a more appropriate and accurate depreciation accrual based upon current circumstances, and will better match the cost of I&M's plant in service with the periods expected to benefit. The record demonstrates that the timely use of depreciation rates that accurately reflect the expected service lives of assets is consistent with accounting and financial reporting standards and expected by the financial community. Accordingly, we find that I&M's revised depreciation rates should be approved and I&M is authorized to place into effect for accrual accounting purposes, the revised depreciation accrual rates set forth in Petitioner's case-in-chief and revised in Petitioner's rebuttal. The total amount of adjustments as a result of I&M's concurrence with certain OUCC recommendations amount to a reduction of the annual depreciation expense presented in the depreciation study and presented in the Company's case-in-chief of $1,519,341 (approximately $988,000 Indiana Jurisdictional) based on plant in service at December 31, 2010. This results in an increase in annual depreciation expense to reflect the new rates of $35,171,972 on a total Company basis based on depreciable plant in-service at December 31, 2010.

11. **Net Operating Income at Present Rates.** Based upon the evidence and the determinations made above, we find Petitioner's adjusted Indiana Jurisdictional operating results under its present rates are as follows:

Operating Revenues	$ 1,317,619,998
O&M Expenses	$ 1,007,306,250
Depreciation/Amortization	$ 116,950,608
Other Taxes	$ 53,305,976
State Income Tax	$ 4,538,761
Federal Income Tax	$ 29,800,015
Total Operating Expenses	$ 1,211,901,609
Net Operating Income	$ 105,718,389

In summary, we find that with appropriate adjustments for ratemaking purposes, I&M's annual net operating income under its present rates for electric utility service would be $105,718,389, which represents a rate of return of 2.87% on its fair value rate base of $3,682,439,595 (Indiana Jurisdictional). We find that this opportunity is insufficient to represent a reasonable return. We therefore find that Petitioner's present rates are unjust, unreasonable, and confiscatory.

12. Authorized Revenue Requirement. On the basis of the evidence presented in these proceedings, we find that Petitioner should be authorized to increase its basic rates and charges to produce additional operating revenue of $102,395,208. After accounting for offsets and decreases in the rate adjustment mechanisms, this results in a net annual increase in revenues of $84,986,897 over adjusted test year operating revenues. This revenue is reasonably estimated to afford Petitioner the opportunity to earn net operating income of $167,197,805 as follows:

Operating Revenues	$ 1,420,015,206
Less: O&M Expenses	$ 1,007,306,250
Depreciation/Amortization	$ 116,950,608
Other Taxes	$ 54,861,257
State Income Tax	$ 10,794,971
Federal Income Tax	$ 62,904,316
Total Operating Expenses	$ 1,252,817,401
Net Operating Income ("NOI")	$ 167,197,805
Less: NOI at Present Rates	$ 105,718,389
Increase Required	$ 61,479,416
Times: Revenue Conversion Factor	1.6655
Jurisdictional Revenue Deficiency	$ 102,395,208
Less: OATT Costs	$ (17,408,311)
Authorized Increase in Revenue	**$ 84,986,897**[1]

13. Revenue Allocation.

A. Cost of Service Methodologies.

(1) I&M Case-in-Chief. Daniel E. High, AEPSC Regulatory Consultant - Regulatory Strategy Department, presented Petitioner's class cost-of-service study at present rates, Petitioner's Exhibit DEH-1, which allocates the total Indiana retail jurisdiction rate base, revenues and expenses to each rate schedule. He explained that the cost allocation methodology used in the class cost-of-service study assigns costs among the customer classes in a fair and equitable manner based on principles of cost causation. Customers who cause costs to be incurred are allocated such costs in the Company's class cost of service study. Mr. High also explained that the Indiana retail jurisdictional accounting cost information was assigned among the customer classes using the utility standard three-step process to assign costs:

[1] Tables contained in this Order are for demonstrative purposes only. The dollar amounts in the tables, especially total amounts, reflect the actual amounts in the Commission's workpapers; however, some numbers, such as percentages or conversion factors, are rounded when they are included in the table. As a result, mathematical calculations done using only the numbers in the table may not be reflective of the actual calculations in the Commission's workpapers.

functionalization, classification, and finally, allocation. He stated the five principal customer classes are residential, commercial, industrial, outdoor lighting and street lighting. He explained that while some costs are directly assignable to a single class, or even a single customer, most costs are joint costs attributable to more than one type of customer and must be allocated to customers by an allocation methodology that is based on the manner in which the costs are caused by the different customers. He stated the joint costs are incurred based on the capacity demanded, the energy used or the number of customers. He stated that when this process is completed and all of the costs are allocated to the customer classes, the result is a fully allocated cost of service study that establishes cost responsibility and the test year rate of return earned from each class, making it possible to determine the rates each class of customer should pay based on costs that are just and reasonable. Mr. High testified that I&M, for class allocation purposes, used the summer and winter peak method to assign customer costs to reflect two seasonal peaks. He stated that the 6 CP is the most appropriate demand allocator considering the load profile during the test period ended March 31, 2011 reflects six monthly peaks, three during the summer and three during the winter, which supports the use of a 6 CP allocator. He stated the benefit of the 6 CP demand allocator is that each customer class is being allocated their fair share of demand costs based on their contributions to the average of the six monthly peaks during the test period.

As required by the terms of the Stipulation and Settlement Agreement approved in Cause No. 43306, Mr. High also presented a minimum system study. He testified that the minimum system approach does not accurately classify distribution poles, lines and transformers (accounts 364 through 368) considering such distribution facilities have a load carrying capability associated with them. He explained that given the reality that demand drives the costs that are incurred for these facilities, and the fact that the Company plans and sizes its equipment to meet customers' peak demand on these distribution facilities, it is only appropriate to use a demand classification. He described the Company's method of classification of distribution plant and stated it is a method that has been adopted in cases before this and other Commissions. He explained that the classification of services and meters as customer-related and primary and secondary poles, lines and transformers as demand-related recognizes the standard engineering practice to plan the distribution facilities to meet the maximum expected demand on the system, not necessarily the number of customers being served by the facilities. He stated it is more appropriate to classify services and meters as customer-related since a single service is required to serve each customer. For other distribution facilities, he explained, a diversified mix of commercial and residential customers will be served from those facilities, and it is the customers' demand placed on those facilities that drives the size and cost of the distribution facilities; not the absolute number of customers served from those facilities. Mr. High testified that the benefit of the Company's approach in classifying distribution plant is that each customer class is being allocated its equitable share of distribution facilities based on contributions to peak demand associated with accounts 360-368, and number of customers related to accounts 369-373.

Mr. High described in detail the allocation of production O&M expense, transmission O&M expense, distribution O&M expense, customer accounting, customer services and sales expense, A&G expense, depreciation and amortization expense, other regulatory expense items and taxes. Mr. High also presented a summary of the resulting earned rates of return for each class shown in the class cost of service study. He explained that David M. Roush, AEPSC

Director-Regulated Pricing and Analysis, utilized the earned rates of return for each class as a basis for the allocation of the revenue increase required for each class.

(2) **OUCC Case-in-Chief.** Dr. Nicholson provided testimony based on her evaluation of I&M's proposed allocation of the jurisdictional cost of service among the customer classes. First, she argued that I&M inappropriately classified 100% of its production plant as demand-related. She asserted this classification disregards the fact that I&M's past capacity expansion plans were devised in large part to minimize the cost of producing energy. Next, she suggested that using a Peak and Average ("P&A") allocator to allocate the costs of production plant among the customer classes is a more equitable method than Petitioner's 6 CP method because it more closely reflects the causes for the incurrence of those capital costs. She recommended that the costs of transmission, sub-transmission, and primary distribution plant should be allocated on the basis of 12 CP demands because 12 CP demands better reflect the costs of the transmission and primary distribution system which operates year round rather than only in peak periods. Dr. Nicholson stated that a cost of service study based on 12 CP demands would be an acceptable alternative to the OUCC.

(3) **Industrial Group Case-in-Chief.** Nicholas Phillips, Jr., Managing Principal of Brubaker & Associates, Inc., testified that I&M's total Indiana jurisdictional revenue requirement and I&M's electric rates should be based on the actual cost of providing electric service to the Indiana jurisdiction and to each customer class. He asserted that, based on certain operational changes at I&M, the 5 CP method using the five PJM peak load contribution ("PLC") peaks is the most appropriate cost of service methodology. However, if it is determined that no significant changes have occurred with respect to I&M's operations, Mr. Phillips agreed the 6 CP method proposed by I&M should be retained, but with a customer component for the allocation of distribution system costs. He testified that I&M's proposed 6 CP cost of service study understates the level of subsidies, and therefore the LP and Industrial Power ("IP") rates of return, because it fails to use a customer component (minimum system) to allocate certain distribution system facilities. Mr. Phillips also asserted that any method of cost allocation that utilizes a form of average demand or energy to allocate production and transmission investment is at odds with the dominant system peaks on the I&M electric system and should be rejected.

Mr. Phillips offered cross-answering testimony in response to Dr. Nicholson's recommendation to use the P&A allocation methodology. He explained that Dr. Nicholson's proposal would completely reverse previous findings of this Commission with respect to cost of service methodology. He stated the so-called P&A method proposed by Dr. Nicholson inappropriately over-allocates production plant costs to high load factor and off-peak classes, is counter to Commission direct findings on this issue, and should be rejected. He also stated that Dr. Nicholson's proposed allocation of distribution facilities on a 12 CP allocator is at complete odds with sound ratemaking and should be rejected. He stated the 12 CP method is not reflective of the I&M system, I&M planning or reserves and should also be rejected. Mr. Phillips criticized the tactic used by the OUCC witnesses of proposing the peak and average method, which has been consistently and appropriately rejected, and then indicating that it would accept the 12 CP. He characterized it as more like a negotiating strategy and asserted it should also be rejected.

(4) **Fort Wayne Case-in-Chief.** Mr. Heid recommended that the Commission approve I&M's proposed 6 CP methodology for allocating electric generation production plant in the cost of service study. Mr. Heid stated that he agreed with the proposed classification of I&M's electric generation production plant as 100% demand-related and the allocation to the various rate classes based on the 6 CP methodology. He noted that the Commission approved the use of the 6 CP methodology in I&M's last fully litigated rate case in 1993 (Cause No. 39314). He stated there have been few changes in I&M's generating unit portfolio or in its system operating characteristics that would warrant a change in the Commission's historical treatment of production plant investment on the 6 CP basis.

Mr. Heid also recommended that the Commission approve the alternate Minimum Distribution System methodology prepared by I&M for purposes of classifying a portion of certain distribution-related costs as customer-related, which I&M historically has used in its previous rate cases. He disagreed with Mr. High's proposal to discontinue the use of the Minimum Distribution System methodology for purposes of classifying distribution poles, overhead and underground conductors and conduit and line transformers. Mr. Heid asserted that I&M's investment in lines, poles and line transformers is a function of two factors: (1) the length of lines and the number of poles and line transformers, and (2) the size of the lines, poles and line transformers. He stated the length of lines and the number of poles and line transformers, in turn, is a function of the number of customers. Thus, Mr. Heid asserted, there is a close and direct relationship between the investment in primary and secondary lines, poles and line transformers with the number of customers served, thereby establishing a reasonable basis for a portion of the lines, poles and line transformers to be classified on a customer basis for cost allocation purposes.

In Cross-Answering Testimony, Mr. Heid recommended the Commission reject Dr. Nicholson's use of the P&A methodology and what he identified as the Equivalent Peaker methodology ("EPM"). Mr. Heid explained that although Dr. Nicholson refers to her approach generically as the P&A methodology, and then states she uses two different approaches to quantify the percentage split between demand costs and energy costs, she actually presents two different methodologies - the P&A methodology and the EPM. Therefore, he referred to Dr. Nicholson's proposal as the "P&A/EPM" methodologies. He stated that Dr. Nicholson's argument in this case is a repeat of the same argument the OUCC presented in a number of previous electric rate cases, which the Commission has consistently rejected. Mr. Heid explained that Dr. Nicholson's P&A/EPM methodologies are subject to a number of conceptual and technical flaws that have formed the basis for the Commission's consistent rejection of similar energy-weighted demand cost allocation proposals. Mr. Heid recommended the Commission approve I&M's continued use of its 100% demand classification of production plant, which should be allocated to customer classes based on the 6 CP methodology. He also disagreed with the OUCC's recommended use of the 12 CP allocation methodology, stating that Dr. Nicholson has not offered any basis for the use of the 12 CP allocation methodology, other than as a compromise position.

(5) **Kroger Case-in-Chief.** In his Cross-Answering Testimony, Neal Townsend, a Director for Energy Strategies, LLC, presented the Average and Excess Demand method for the Commission's consideration in response to Dr. Nicholson's proposal to adopt the P&A method. He made clear that he does not recommend the Commission abandon the 6 CP

method. However, if the Commission were to adjust its approved production cost allocation method in response to Dr. Nicholson's argument to recognize average demand requirements, Mr. Townsend opined it would be far more reasonable to adopt the Average and Excess Demand method than the P&A method proposed by Dr. Nicholson.

(6) **I&M Rebuttal.** Mr. Roush responded to the OUCC's and Intervenors' recommendations regarding the class cost-of-service study. He disagreed with Dr. Nicholson's recommendation to use an energy-weighted demand allocation methodology (P&A) for production plant, explaining that her approach is not internally consistent in its treatment of the allocation of all costs, including fuel costs, is not consistent with Commission-approved methodologies for Indiana electric utilities and is not appropriate for I&M based upon the facts presented in this proceeding. He testified that the Company's allocation methodology for production plant is the same methodology used in its previously filed rate case proceedings, has been thoroughly reviewed and analyzed by many parties, and received Commission approval for class cost-of-service development. He also disagreed with Dr. Nicholson's recommendation to use a 12 CP demand allocation methodology to allocate transmission plant, explaining that the Company's retail class load profiles during the test period do not reflect a flat load curve, but rather two distinct seasonal summer and winter peaks. He explained the benefit of the 6 CP demand allocation factor is that each customer class is being allocated their fair share of demand costs based on their contributions to the average of the six monthly peaks during the test period." Mr. Roush testified that the FERC CP test is more applicable in determining the demand allocation on a jurisdictional or total company basis. He said I&M utilizes a 12 CP for demand allocation purposes in its jurisdictional separation study as supported by Ms. Caudill. He stated that because the retail class load shapes are noticeably different when compared to the Company's jurisdictional load shape, the 12 CP is not the most appropriate class cost-of-service demand allocation factor; thus, Dr. Nicholson's 12 CP proposal should be rejected. Mr. Roush also explained that it would be inappropriate to allocate the primary voltage portion of distribution plant based on a 12 CP demand allocation methodology. He added that considering that the Company used a 6 CP demand allocation factor in its previous cases, and the load profile continues to reflect six monthly peaks it is only appropriate to continue the 6 CP demand allocation.

Mr. Roush disagreed with Mr. Phillips's recommendation to use PJM PLC values as the basis in allocating demand costs among customer classes. He explained it is more reasonable that I&M evaluate and consider how its customer classes are contributing to I&M's six monthly peaks (not PJM's peaks). He noted there is no assurance that I&M will peak at the same time that PJM will peak. He explained that the five PJM PLC peaks for the test year were all in the months of July and August 2010. He stated that because I&M has two seasonal peaks, this approach does not represent I&M's needs for planning its facilities based on the three summer and three winter month peak demands. He added that under the Company's demand allocation approach, the 6 CP method does consider how I&M's customer classes are contributing to I&M's three summer and three winter peak months, thereby, giving equal weight to both of these two peak seasons for the Company.

Mr. Roush also agreed with Mr. Heid's recommendation that the Company should continue to classify production plant as 100% demand-related and allocate among the customer classes using a 6 CP methodology. He also agreed with Mr. Phillips that a 12 CP method should not be used for the class cost-of-service study for I&M's Indiana jurisdiction. He explained that the Company classifies and allocates production plant as demand related based on the fixed-cost characteristics of the Company's production resources. Fixed production costs are demand-related. More specifically, production costs vary with capacity additions and are incurred as a result of the Company's planning and building to meet peak demand. He added that these costs do not vary with energy produced from the resources. The Company incurs these costs regardless of customer energy usage. He explained that the Company appropriately allocates production demand-related costs among the customer classes based on each class' contribution to the average of the six monthly peaks during the test period (on the production facilities) as supported by Mr. High's pre-filed direct testimony (at pages 11 through 13). He stated that the Company's retail class load data reflects winter and summer peaks and explained that the Company's proposed 6 CP demand allocation factor has proven to be a stable cost allocation methodology considering the customer class load profiles show consistent summer and winter peak demands.

Mr. Roush explained that the Company did not propose to change its classification of distribution plant in this proceeding. The Company continues to classify distribution plant accounts 360-368 as demand-related and accounts 369-373 as customer related. The Company's classification and allocation of distribution costs as demand-related and customer-related is both well established and widely recognized. Mr. Roush stated that the minimum system approach of classifying a portion of accounts 364-368 as customer related, as Mr. Heid and Mr. Phillips are recommending, does not recognize the Company's standard engineering practice of planning and sizing distribution facilities to meet the peak demand of the customers served by those facilities. As such, the peak demand on Company facilities, not the number of customers served by the facilities, causes the Company to incur distribution facility costs. Mr. Roush explained that Mr. Heid's and Mr. Phillips' proposals do not fully recognize the fact that the facilities, even the minimum facilities, included in accounts 364-368 have a load carrying capability. He said, it is the Company's "actual practice" to plan and construct the equipment included in these accounts to meet expected peak demand. It is demand that is the cost driver. Mr. Roush disagreed with Mr. Heid's view of the NARUC Manual and explained that the Company's classification of distribution plant accounts 364-368 is consistent with the NARUC Manual and is based on principles of cost causation. He concluded that distribution plant costs included in accounts 364-368 are incurred based on peak demand. Therefore, the costs included in these accounts should be classified as demand-related and allocated using the Company's demand allocation factors. This classification and allocation of distribution plant used by the Company continues to be an appropriate method due to its foundation in cost-causation.

Finally, Mr. Roush explained that Dr. Nicholson's claim that the Company's class cost of service study allocations are inconsistent with the allocations in the OSS margin sharing rider compares apples to oranges and should be rejected. He also explained why he disagreed with Joseph Jancauskas's, Inovateus Vice President of Engineering, contention that I&M should consider implementation of a feed-in-tariff.

(7) <u>Commission Discussion and Findings.</u> We find that the results of I&M's jurisdictional separation and retail cost of service studies should be accepted and utilized to allocate operating revenues among customer classes and to design I&M's retail electric rates. Based on the evidence, we find that the criteria identified by Mr. High and supported by Mr.

Roush for determining the appropriateness of an allocation methodology are sufficiently supportive of the cost allocation methods used to prepare Petitioner's class cost of service study. Accordingly, I&M's class cost of service study is a reasonable allocation of costs among the customer classes based on contributions to demand and energy levels and number of customers at this time. However, as discussed below, a variety of factors indicate that a comprehensive and fresh analysis of this issue will be warranted in the near future.

(a) **Demand Allocation Methodology.** I&M proposed to classify electric generation production plant as 100% demand-related and allocate it to the various rate classes based on the 6 CP monthly loads for the three summer months of June, July, and August and the three winter months of December, January, and February. This Commission approved the same demand classification and 6 CP allocation methodology for production plant in I&M's 1993 rate case, Cause No. 39314. 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, 2004 Ind. PUC LEXIS 150, at *289 (IURC May 18, 2004). More recently, in *N. Ind. Pub. Serv. Co.*, we found: "our preference is to utilize the previously approved allocation methodology, given sufficient evidence, unless system operating characteristics are demonstrated to have changed since the last approved cost of service study allocation methodology." Cause No. 43526, 2010 Ind. PUC LEXIS 294, at *263 (IURC Aug. 25, 2010); see also *S. Ind. Gas and Elect. Co.*, Cause No. 43839, 2011 Ind. PUC LEXIS 115, at *189 (IURC April 27, 2011). Mr. Heid noted that there have been few changes in I&M's generating unit portfolio or in its system operating characteristics that would warrant a change in the Commission's historical treatment of production plant investment on the 6 CP basis that was approved in Cause No. 39314.

Our approval of the 6CP allocation in Cause No. 39314 was a tempered endorsement however, as we stated:

> While we are not convinced that the Company's 6 CP methodology is superior to the 12 CP methodology utilized in I&M's previous cost-of-service studies, we are unable to find sufficient support in the record for using the 12 CP methodology as proposed by Mr. Johnson. We agree that the Company's proposed 6 CP method, also endorsed by ICFUR witness Baron, focuses on the winter and summer months that have caused, and will continue to cause, I&M to incur production and transmission costs in the future. However, the 12 CP method is often utilized to reflect the full range of operating realities throughout the year including the system demand scheduled maintenance and reserve requirements. This is especially true for I&M because of the large size of the Cook and Rockport units. We also note that I&M's jurisdictional study used a 12 CP methodology. However, based upon the recommendations of Company Witness Jahn and ICFUR Witness Baron, we will allocate production costs, for class cost-of-service purposes, using a 6CP methodology.

Cause No. 39314 Order at Page 171. Further, the class allocation of revenue requirements that are presently in place are the result of the settlement approved in Cause No. 43306, and a review of revenue allocations under the variety of allocation methodologies proposed by the parties in that proceeding would not suggest that a 6 CP allocation served as the basis for the settlement result. We also recognize the underlying operation of the I&M generation portfolio is likely to undergo material changes as the method under which I&M interacts with the AEP-East System changes with the unbundling of that system.

However, the evidence that is before us in this proceeding is reasonably supportive of the Company's proposed allocation methodology. The Company's load profile on the primary distribution system during the test period supports a 6 CP allocation. As evidenced by Mr. High's testimony and workpapers and Mr. Roush's rebuttal testimony, the load data reflects six monthly peaks, three during the summer and three during the winter, which supports the use of a 6 CP allocation factor. Considering that the Company used a 6 CP demand allocation factor in its previously filed cases, that the 6 CP demand allocation was last approved by this Commission in a fully litigated case, and since the load profile continues to reflect six monthly peaks, we find it is appropriate to continue the 6 CP demand allocation.

(b) Transmission and Distribution Plant Allocation Methodology. The parties also disagreed over the methodology of allocating transmission and distribution plant. The OUCC recommended that transmission be allocated based on a 12 CP methodology. Fort Wayne and the Industrial Group recommend reallocating a portion of distribution accounts 364 through 368 as customer-related.

Consistent with our discussion above, we reject the OUCC's recommendation that transmission be allocated based on a 12 CP methodology. We also reject Fort Wayne's and the Industrial Group's recommendation to change the classification of distribution plant accounts 364 through 368 to classify and allocate a portion of these accounts as customer-related. The Company's classification of distribution plant accounts 364-368 is consistent with the NARUC Manual and is based on principles of cost causation. Accordingly, we are persuaded that distribution plant costs included in accounts 364-368 are incurred based on peak demand and should be classified as demand-related and allocated using the Company's demand allocation factors. I&M's proposed classification and allocation of distribution plant continues to be an appropriate method due to its foundation in cost-causation.

B. Subsidy Reduction.

(1) I&M Case-in-Chief. Mr. Roush sponsored I&M's Indiana-jurisdictional cost-of-service study at proposed rates, including the calculation of the interclass subsidies and the distribution of revenues to rate classes. He calculated the current subsidy for each class and explained the equal percentage subsidy reduction method of revenue allocation reflected in the Company's revenue allocation. Mr. Roush explained that the process reflects the exercise of the principle of gradualism. He explained that while it is not reasonable to eliminate all subsidies in this case, it is important to make progress toward eliminating interclass subsidies. He added that the amount of such progress should be tempered by recognition of the rate impacts on the various tariff classes. As such, I&M proposes to eliminate 50% of the current subsidies from all classes.

(2) OUCC Case-in-Chief. Dr. Nicholson testified that she supports Mr. Roush's proposal to move towards the full cost of service rates, but recommended that this be done in moderation, particularly given current economic conditions. She stated that Mr. Roush's approach that first calculates the "current subsidy" implied by Petitioner's cost of service study and retains half of that subsidy is a reasonable first step to establish class revenue responsibilities. She suggested an additional constraint that no customer class faces an increase in excess of 1.5 times the system average increase of 19.14%.

(3) **Industrial Group Case-in-Chief.** Mr. Phillips agreed that I&M's proposed rate design is reflective of cost and is appropriate, even though subsidies remain in the rate structure. He noted I&M's proposed method of distributing its requested rate increase to classes reduces existing interclass subsidies by 50% and moves rates closer to cost. He suggested that another method would be to phase out subsidies until all existing interclass subsidies are reduced by 100%. To the extent I&M's proposed level of rate increase request is reduced, Mr. Phillips recommended consideration be given to moving rates even closer to cost of service than the 50% subsidy reduction proposed by I&M.

(4) **Commission Discussion and Findings.** We agree with the parties that I&M's proposed method of distributing its requested rate increase in a manner to reduce current interclass subsidies by 50% 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. Therefore, we approve Petitioner's proposal.

14. Rate Design. The disputed rate design issues are discussed below.

A. Voltage Differentiated Fuel Factors.

(1) **I&M Case-in-Chief.** In Cause No. 38702 FAC 62 S1, the Commission approved a stipulation and settlement agreement, which included a requirement that on or before October 31, 2011, the Company make a filing that provides both voltage differentiated fuel factors for customers served at secondary, primary, subtransmission, and transmission voltages, and the uniform FAC factors that I&M typically files in each FAC case. In its filing, the Company proposed to change the FAC base cost of fuel to 18.458 mills/kWh, which is consistent with the uniform FAC factors that I&M typically files. As explained by Mr. Roush, Petitioner's Exhibit DMR-2 presented the calculation of the FAC base cost of fuel by voltage based upon the energy sales data by delivery voltage and the energy loss analysis prepared in this proceeding. He said sample calculations of fuel adjustment factors under such an approach are also presented in this exhibit. He stated that this information was provided to permit all parties to address issues and make specific recommendations to the Commission related to both the uniform and the voltage differentiated FAC rates.

(2) **OUCC Case-in-Chief.** The OUCC recommended that the Commission retain I&M's current uniform fuel factor. Mr. Eckert testified that he is not conceptually opposed to voltage-differentiated FACs, but he does not believe sufficient detail has been provided, such as a sample FAC application with supporting workpapers demonstrating how voltage delivery and energy losses would be utilized in a FAC proceeding, to advocate adoption by the Commission of the voltage-based FAC concept and presentation. Mr. Eckert also requested that the Commission allow the OUCC to file its testimony and report 35 days after I&M files its Application and testimony in its FAC proceedings.

(3) **Industrial Group Case-in-Chief.** Mr. Phillips testified that the fuel cost recovery mechanism will be more reflective of cost with a line-loss differentiated factor by rate class. He stated this method would extend the line-loss differentiated method commonly used and accepted in base rate design to all fuel cost recovery. He stated line-loss varies by voltage level of service and is a more cost reflective and accurate method of fuel cost recovery. He testified that in recognition of these cost differences, utility fuel costs in base rate cases are typically allocated using energy consumption adjusted to the source for line losses. He stated that although fuel cost in base rates reflects this allocation, fuel costs recovered through the FAC fail to recognize this difference in cost causation. He recommended the difference in fuel cost by classes due to voltage levels be addressed in the FAC proceeding and require a different fuel adjustment factor for each rate class reflecting the lower cost to serve high voltage customers in order to appropriately match the cost to serve to the customers causing the costs.

(4) **SDI Case-in-Chief.** Dennis W. Goins, PhD, of Potomac Management Group, recommended that the Commission approve the voltage-differentiated base fuel rates presented in I&M's filing and that the Commission require I&M to submit future FAC filings that reflect voltage-differentiated fuel factors linked to voltage-differentiated FAC base rates approved in I&M's most recent general rate case. He asserted that the current use of a non-voltage-differentiated fuel charge forces high-voltage customers to subsidize low-voltage customers. He contended the subsidies are large, unfair, and unnecessary-problems that can be easily and justifiably mitigated by differentiating I&M's fuel factor by delivery voltage.

In Cross-Answering Testimony, Mr. Goins responded to Mr. Eckert's recommendation to retain I&M's current uniform fuel factor, stating that Mr. Eckert's concerns are misplaced and the Commission has more than sufficient information in this case to set a voltage-differentiated fuel basing point for each of I&M's four principal voltage service levels.

(5) **I&M Rebuttal.** Mr. Krawec responded to Mr. Eckert's proposal to increase the amount of time for the OUCC to report on I&M's FAC filings. He explained that Mr. Eckert's testimony failed to justify nearly doubling the available days for the OUCC's report. He further explained that I&M did not advocate a change to a voltage differentiated FAC but merely presented information on this concept. Even if a voltage differentiated FAC is adopted, Mr. Krawec explained that this should not require additional time on the part of the OUCC for its FAC audit.

(6) **Commission Discussion and Findings.** Petitioner has not requested a change to a voltage-differentiated FAC in this proceeding. The OUCC recommends against adoption of such a change at this time. Intervenors Industrial Group and SDI have advocated for the shift, stating that it is a more accurate matching of fuel cost and fuel cost recovery by customer class than the current method in FAC proceedings and should be implemented. I&M presented information on voltage differentiation in compliance with the stipulation and settlement agreement approved in Cause No. 38702 FAC 62 S1 in order to permit the parties to address issues and make specific recommendations to the Commission related to both the uniform and the voltage-differentiated FAC rates. We find that changing to a voltage-differentiated FAC would add unnecessary complexity to the expedited FAC process without producing a material change in the outcome. Therefore, we decline to adopt a voltage-differentiated FAC in this proceeding.

B. **L.G.S. (Large General Services) Rate Schedule.**

(1) **I&M Case-in-Chief.** Mr. Roush testified that I&M was pleased with the success of the consolidation of Tariffs Q.P. and I.P. into a single Tariff I.P. approved in its last basic rate case. He indicated that I&M believed a consolidation may ultimately make sense for Tariffs M.G.S. (Medium General Services) and L.G.S., but that such a consolidation is too ambitious and expensive to achieve at this time given the differences in metering requirements and the power factor provisions. To promote the ultimate consolidation of these Tariffs, I&M proposed to incorporate a load factor blocking at 300 hours use per month into Tariff L.G.S. to take the first steps towards a potential consolidation and also to provide L.G.S. customers with the advantages that such a structure provides for customers whose load factor varies.

(2) **Kroger Case-in-Chief.** Mr. Townsend recommended the Commission reject I&M's proposed redesign of the L.G.S. rate schedule and instead require I&M to retain the same basic rate design for that rate schedule, while improving alignment between costs and charges by setting base demand charges for L.G.S. Secondary and Primary at 65% of demand-related costs with a corresponding reduction in the base energy charges to achieve the target revenue requirement for each L.G.S. subclass. He also recommended that the base demand charges for L.G.S. Subtransmission be set at 70% of demand-related costs with a corresponding reduction in the base energy charges to achieve the target revenue requirement for this subclass.

(3) **Industrial Group Cross-Answering Testimony.** Mr. Phillips testified that Rate L.G.S. should be designed to properly reflect demand and energy costs in the demand and energy components of the rate. He stated that the L.G.S. rates Mr. Townsend starts with still have subsidies in them and do not represent the actual costs resulting from the costs of service study. However, Mr. Phillips agreed that the L.G.S. rate proposed by I&M should be modified to be more reflective of cost of service.

(4) **I&M Rebuttal.** Mr. Roush disagreed with Mr. Townsend's characterization of I&M's changes to Tariff L.G.S. as a radical redesign. He noted that such a redesign was already implemented for I&M's largest customers served under Tariff I.P. I&M's redesign of Tariff L.G.S. is designed to align it with Tariff I.P., which contains a load factor block structure that is similar to the one being proposed for Tariff L.G.S. Mr. Roush explained the changes to Tariff L.G.S. reflect I&M's experience with ongoing customer migrations between L.G.S. and I.P. tariff classes and the potential future consolidation of Tariffs M.G.S. and L.G.S.

Mr. Roush explained that Mr. Townsend's proposal to maintain the current design is less favorable when all Tariff L.G.S. customers are considered. He stated that a load factor based tariff structure, such as that adopted in I&M's proposed Tariff L.G.S., provides a better fit for customers across a range of usage characteristics and provides rate continuity for customers as customer usage changes. Mr. Townsend's proposal establishes a certain amount of demand costs to include in the demand charge and leaves the remainder included in energy charges resulting in winners and losers among the higher and lower load factor customers within that class, according to Mr. Roush. He noted that the impacts of Mr. Townsend's redesign are significantly higher on lower load factor customers than on higher load factor customers.

Mr. Roush did propose a modification to the Tariff L.G.S. rate design that more equally distributed the rate increase among lower and higher load factor L.G.S. customers. He indicated that I&M is willing to adjust its proposed L.G.S. rate design to reflect this modification.

(5) **Commission Discussion and Findings.** I&M has proposed to make modifications to Tariff L.G.S. that better align the tariff with Tariff I.P. and reflect I&M's experience with ongoing customer migration between the two tariff classes. Mr. Townsend recommended Rate L.G.S. be designed to better meet Kroger's needs. However, Mr. Townsend's proposal is unreasonable when all Tariff L.G.S. customers are considered. The impacts of Mr. Townsend's redesign are significantly higher on lower load factor customers than on higher load factor customers. We find that Mr. Townsend's concerns are reasonably addressed by the tariff modifications proposed in Mr. Roush's rebuttal testimony. Mr. Roush's revisions more equally distribute the rate increase among lower and higher load factor L.G.S. customers and results in rate continuity for customers as usage changes. Therefore, we approve I&M's modification to the Tariff L.G.S. described in Mr. Roush's rebuttal testimony. The methodology moderates the impact of the increase by spreading it out across all demand levels.

C. Rate Adjustment Mechanisms.I&M Case-in-Chief. The Company proposed to maintain its existing rate adjustment mechanisms, including the PJM Cost Rider, Clean Coal Technology Rider ("CTTR") and Environmental Compliance Cost Recovery Rider ("ECCR") established in Cause No. 43306.

(2) **OUCC Case-in-Chief.** Mr. Jasheway agreed with the continuing operation of the PJM Cost Rider as approved in Cause No. 43306, including maintaining the current level of PJM administrative costs in basic rates and the treatment of FTR revenues. He also agreed with I&M's proposal to incorporate credits resulting from FERC Docket No. ER09-1279 at the same time I&M implements new basic rates resulting from this Cause.

(3) **Industrial Group Case-in-Chief.** Mr. Dauphinais testified that he has no issue with I&M's proposal to return the Indiana jurisdictional portion of the retail ratemaking credits through the PJM Cost Rider.

(4) **Commission Discussion and Findings.** The parties are in agreement that the Retail Ratemaking Credits resulting from FERC Docket No. ER09-1279 should be included in Petitioner's PJM Cost Rider, and we concur. We find that the PJM Cost Rider should continue to operate as approved in Cause No. 43306, and the credits resulting from FERC Docket No. ER09-1279 shall be included in the Rider.

No parties filed testimony in opposition to Petitioner's proposal with respect to its CCTR or ECCR. We approve I&M's request to eliminate the amounts being collected in the CCTR associated with the pollution controls approved in Cause No. 43636 as of the effective date of new rates in this proceeding and I&M's proposed reconciliation in its next CCTR filing. We agree with I&M's proposal to use the CCTR for similar construction costs and operating expenses approved by this Commission. We also find that I&M's ECCR and other rate adjustment mechanisms shall continue as proposed by I&M.

D. Tariff, Rules and Regulations.

(1) **I&M Case-in-Chief.** Mr. William W. Hix, Principal Regulatory Consultant, discussed the modifications to I&M's Terms and Conditions of Service and Tariffs. Mr. Hix explained that the proposed modifications are primarily due to either clarifying the existing term and condition or Company policy and that the clarifications will benefit customers by better explaining the Company's and the customer's obligations. Mr. Hix also explained that I&M's filing included the following tariff proposals.

(a) **Equal Payment Plan ("EPP").** Mr. Hix explained that I&M included a proposal to limit the EPP to those customers currently enrolled under the plan. Mr. Hix noted that, based upon I&M's experience since the implementation of the Average Monthly Payment Plan ("AMPP") in Cause No. 43306, I&M has found that the AMPP payment plan provides a smoother and more consistent monthly payment than the EPP. Mr. Hix explained that many EPP residential customers have encountered high bills to pay for their settlement month under the EPP. He further explained that the AMPP will eliminate these single-month high bills and provide better consistency, which is what most customers are seeking.

(b) **Dishonored Negotiable Instrument ("DNI").** Mr. Hix testified that the Company's proposal to increase the fee charged for a DNI received in payment for a bill is needed to provide a more appropriate incentive to certain customers to not issue such an instrument. He explained that an increased fee from the current charge of $7 to $20 will not only put I&M in line with Indiana's other investor owned utilities but should also encourage a reduction in the number of such transactions. Mr. Hix also testified that the revenue amount resulting from the proposed increase in the DNI charge of $51,966 is reflected in the Company's proposed revenue allocation as a reduction to the required basic rate increase as shown in Petitioner's Exhibit DMR-1 sponsored by Mr. Roush.

(c) **Reconnection Fee and Service and/or Disconnect and Reconnect Charge Rates.** Mr. Hix explained that the Company added a fee for reconnections made at a pole on Sundays or holidays. He testified that the addition of a Sunday and holidays reconnection fee at a pole provides another option for reconnections that benefits those customers that might need such service.

Mr. Hix testified that, although the Company is not proposing an increase in the rates charged for Service and/or Disconnect and Reconnect Charges in this proceeding, per the Commission's Order in Cause No. 43306, these charges will increase on March 23, 2012. He explained that the revenue impact of the approved Service and/or Disconnect and Reconnect Charge rates increases from Cause No. 43306 was estimated based on the number of transactions occurring during the test year. He testified that Operating Revenue Adjustment No. 15 of Petitioner's Exhibit A-5 increases I&M's Indiana jurisdictional operating revenues by $604,127 to reflect this increased revenue and that if this adjustment was not made, I&M's total company operating revenues would be understated.

(d) **Employee Rate for Tariff R.S. TOD2.** Mr. Hix testified that I&M proposed to add an Employee Rate for Tariff R.S.-TOD2. He explained that the Company expanded the availability of Tariff R.S.-TOD2 outside of the former South Bend Smart Meter Pilot Program area and neglected to propose an employee rate for this tariff. Mr. Hix stated that expanding this offering to employees is appropriate and consistent with past practices.

(e) **<u>Tariff Modifications and Additions</u>.** Mr. Hix explained that the proposed tariff book has been reorganized slightly to sequentially group tariffs that are similar, such as Tariffs I.P., CS-IRP, and CS-IRP2. He explained that the rider tariff sheets have been grouped by non-surcharge and surcharge riders and a cover sheet for the surcharge riders was inserted to provide a convenient reference to all applicable surcharge riders. Mr. Hix noted that the Company believes the reorganization of the tariff sheets and the addition of the surcharge riders cover sheet will simplify reading the tariff book and determining all applicable tariff rates. Mr. Hix also discussed the following proposed new tariffs, new tariff options, and major modifications to tariffs.

(i) **<u>New Senior Citizen Tariff.</u>** Mr. Hix testified that I&M is proposing the addition of a residential tariff available to senior citizens and he explained that all residential customers, 65 years of age and head of household, are eligible for the proposed Tariff R.S.-SC. Mr. Hix stated that I&M's most vulnerable customers are its fixed-income senior citizens. For those qualifying senior citizens that are low usage (less than 1,000 kWh per month) customers, the proposed tariff offers them an opportunity to reduce their monthly electrical energy costs that they would otherwise see under Tariff R.S. He noted that Mr. Roush discussed the rate design for the proposed tariff.

(ii) **<u>New Tariff Option to Tariff R.S.-OPES (Residential Off-Peak Energy Storage).</u>** Mr. Hix stated that I&M's approved Tariff R.S.-OPES is currently available to customers who use energy storage devices with time-differentiated load characteristics such as electric thermal storage space-heating equipment and water heaters which consume electrical energy primarily during off-peak hours. He explained that I&M is planning to begin an evaluation of customer utilization of Plug-in Electric Vehicles ("PEVs") throughout its Indiana electric service territory and specifically, the operational impacts of charging PEVs, the benefits of utilizing off-peak charging of PEVs and the associated infrastructure requirements. He also explained that, to assist with this evaluation, I&M is proposing to rename its current Tariff R.S.- OPES to Tariff R.S.-OPES/PEV (Residential Off-Peak Energy Storage/Plug-In Electric Vehicle) and include a voluntary optional provision for PEV charging stations programmed to consume electrical energy primarily during off-peak hours, for equipment-qualifying customers to receive service under the tariff.

Mr. Hix also testified that I&M's proposed Tariff R.S.-OPES/PEV includes an Experimental Electrical Vehicle Supply Equipment ("EVSE") Option where the Company will reimburse up to $2,500 toward the purchase of Company approved PEV supply equipment. PEV supply equipment is defined in the proposed Tariff as the charging station including conductors, the ungrounded, grounded, and equipment outlets, or apparatus installed specifically for the purpose of delivering electric energy from the premises wiring to the PEV, if not otherwise provided, and installation costs of a separately metered circuit. Mr. Hix explained that the Company benefits from the collection of separately metered PEV usage through this provision. He also explained that although the reimbursement option will be made available to the first 250 qualifying customers that properly apply for such option, there is no limit in the number of customers that may receive service under Tariff R.S.-OPES/PEV. He concluded this part of his testimony by stating that the proposed terms and conditions of service are reasonable and the rates under the Tariff for a PEV customer are not different from the rates proposed for all other Tariff R.S.-OPES/PEV customers.

Mr. Hix testified that the Company requests that the Commission approve the revised Tariff R.S.-OPES/PEV and authorize, for ratemaking purposes, the deferred recovery of the expenses incurred for the EVSE Option. He also explained that the total amount deferred is limited to the maximum per customer reimbursement amount ($2,500) and the maximum number of eligible customers (250) for a total of $625,000 and that the deferral period of this expense would be from the time the revised Tariff R.S.-OPES/PEV is approved by the Commission until the expense is included in a subsequent general rate case. Additionally, the Company requests the assured recovery of the deferral of costs through the recordation of a regulatory asset and the Company will include the amortization of this asset in a subsequent general rate case.

(iii) **Tariff O.L. (Outdoor Lighting).** Mr. Hix testified that the addition of a post-top lamp to Tariff O.L. is needed to address the frequent requests for such lamps. He discussed the fact that I&M currently provides this same lamp under its street lighting tariff but it is not currently available under Tariff O.L. He also stated that the customers requesting this post-top lamp are typically not eligible for service under the streetlight tariff.

(iv) **Tariff S.G.S. (Small General Services) and M.G.S. (Medium General Services) Consolidation.** Mr. Hix explained that I&M is proposing a consolidation of Tariffs S.G.S. (Small General Service) and M.G.S. (Medium General Service) into one tariff (Tariff G.S.). The introduction of Tariff G.S. will also require canceling Tariffs S.G.S. and M.G.S. Consolidating the two tariffs (S.G.S. and M.G.S.) into one tariff will benefit those customers whose usage varies such that some months of the year they would be better off receiving service under Tariff S.G.S. and some months of the year under Tariff M.G.S. Those customers that do not fall into this category will basically see little if any real change from their current billing other than the proposed increases in rates that they would otherwise be seeing as a result of this Cause.

Mr. Hix also testified that the consolidation of Tariffs S.G.S and M.G.S. will prompt the need to rename Tariffs S.G.S.-TOD and M.G.S.-TOD to G.S.-TOD2 and G.S.-TOD, respectively. Due to its association with proposed Tariff G.S., Tariff G.S.-TOD will be expanded to include secondary and primary service offerings and the lower availability threshold will be reduced from 10 kW to zero kW. Mr. Hix also explained that by consolidating the two tariffs into one tariff, the Company will be positioned to provide better customer service and management of the customers qualifying for the new consolidated tariff. Company Witness Roush explains the rate design for the proposed consolidated tariff.

(v) **Tariff L.G.S. (Large General Services) Modification.** Mr. Hix stated that the Company is proposing to implement in I&M's existing Tariff L.G.S. (Large General Service) a load factor blocking that mirrors the load factor relationship contained in Tariff I.P. (Industrial Power). He explained that the implementation of this mechanism will provide a better transition for those customers that become ineligible for Tariff L.G.S. and must migrate to Tariff I.P. and those Tariff I.P. customers that may benefit from a migration to Tariff L.G.S. Mr. Roush explains the rate design for this proposal.

(vi) **Additional Tariff and Rider Modifications or Language Changes.** Mr. Hix also discussed that the Company is proposing an additional provision to

Tariff E.C.L.S. (Energy Conservation Lighting Service) to address those rare instances when customers request the removal and/or relocation of lamps. The proposed revision reflects the Company's terms and conditions regarding such customer requests to remove and/or relocate Company facilities while also providing for certain issues that may arise in fulfilling such requests that involve streetlights. Mr. Hix explained that the addition of the provision provides customers with a clear and concise expectation when considering making such requests for the removal and/or relocation of Company facilities that provide streetlight service. He also testified that the Company is proposing an increase in the amount of discount a customer qualifying for an Economic Development Rider ("EDR") would receive. Mr. Hix explained that the current discount is based on a percentage of the Tariff I.P. (Industrial Power) demand charge. He stated that in Cause No. 43306, the EDR was renewed with only slight modifications after having been expired for several years. Mr. Hix explained that, in Cause No. 43306, Tariff I.P. was redesigned such that the demand charges were reduced by approximately 200-300%. The unintended consequence of this approved change to Tariff I.P. was that on a dollar for dollar basis, the EDR discount offered today is considerably less than the EDR discount that was offered several years ago. An increase in the EDR discount percentage as proposed will put the EDR discount more on par with the level of EDR discounts from several years ago as well as help to incent customers to locate and expand in I&M's service territory which will benefit I&M, I&M's other customers, the communities I&M serves, and the State of Indiana.

Mr. Hix also identified that Company's proposed clarifying language to Rider AFS (Alternate Feed Service). Rider AFS approved in Cause No. 43306 currently indicates that the rider is applicable to those customers requesting new or upgraded AFS and those customers provided AFS under an approved contract. Mr. Hix reported that, since the rider's approval on March 4, 2009, all issues regarding customers under a previously approved contract have been addressed. Mr. Hix explained that the word "upgrade" has caused some confusion and that the proposed wording clarifies that an upgrade refers to a required expenditure by the Company in order to continue providing an existing AFS that is not under contract. He stated that the clarifying language does not change any approved provisions or applications of Rider AFS but only serves to better explain the provisions of Rider AFS.

(vii) <u>Closing or Cancelled Current Tariffs or Riders.</u> Mr. Hix discussed I&M's proposal to close or cancel Tariff E.H.S. (Electric Heating Schools), and Riders ECS (Emergency Curtailable Service) and EPCS (Emergency Price Curtailable Service). He explained that Tariff E.H.S. was established in the early 1970's and made available to "primary and secondary schools and to college and university buildings, and additions thereto, where the principal energy requirements, including all lighting, heating, cooling, water heating, and cooking, are provided by electric energy" and stated that Tariff E.H.S. was closed to new business as of April 6, 1981. Over the thirty plus years since the tariff was closed to new business, most of the customers served under this tariff have migrated to other more appropriate tariffs, leaving a small number of accounts remaining on Tariff E.H.S. In addition to the fact that there are only a small number of accounts remaining on Tariff E.H.S., the Company is proposing closing this tariff to all business due to the time and difficulty in verifying that customers continue to qualify for the tariff. Mr. Hix also noted that Tariff E.H.S. is an energy billing (kWh) only tariff; therefore there is no customer price signal to control their electrical demand which is inconsistent with I&M's DSM/EE concepts. Because this tariff is closed to new business, with only a select few customers qualifying, other similar customers are currently being treated inconsistently. While there are similar issues today for Tariffs E.H.G. (Electric Heating General) and M.S. (Municipal and School Service), the number of customers served under those tariffs and associated costs of meter replacements is too high to warrant eliminating those tariffs at this time. Riders DRS1 and DRS2 were approved in Cause No. 43566 PJM1 on April 27, 2011 and May 18, 2011, respectively. With the approval and implementation of these two riders, and the lack of customer interest shown in Riders ECS and EPCS, the Company believes that Riders ECS and EPCS should be closed. Although Riders ECS and EPCS have essentially existed for more than twelve (12) years, no customers have ever committed to any curtailments under the riders; therefore, it is appropriate to close these riders at this time.

(2) <u>OUCC Case-in-Chief.</u>

(a) <u>New Senior Citizen Tariff.</u> Eric M. Hand, Utility Analyst in the OUCC's Electric Division, recommended the Commission reject I&M's proposed Optional Senior Citizen Rate. He expressed concern that seniors will not understand that the discount comes with conditions, particularly that for every month they exceed 1000 kWh, their total bill will exceed the amount they would have paid under the standard residential tariff. He noted there is no cap on the number of kWh charged at the higher rate and that customers participating in the Senior Citizen Rate would be locked in for a full year. Mr. Hand asserted that unless customers have reasonable access to real-time information about their electric usage, they cannot know if they need to modify their consumption behavior to comport with the tariff's conditions. Mr. Hand also asserted that because there is no cap on the number of monthly kWh billed at the highest rate, this tariff could ultimately provide a net financial gain for I&M.

If the Commission approves I&M's proposed Optional Senior Citizen Rate, Mr. Hand recommended the Commission require I&M to work with the OUCC to develop mutually acceptable informational materials and safeguards as well as annual reports regarding customer participation, complaints, sales volumes and other data.

(b) <u>Employee Discounts.</u> With respect to I&M's proposed employee discount rate, Mr. Hand testified that he does not support an approach that requires other residential customers to fund discounts for utility employees. He stated funding for such discounts should come from shareholders, not from other customers. Dr. Nicholson provided testimony that to implement Mr. Hand's recommendation the Company's "Proof of Revenues" for Residential customers presented in Petitioner's Exhibit DMR-4 can be recalculated to omit the employee discounts.

(c) <u>Tariff C.S.-IRP and Tariff C.S.-IRP2.</u> Mr. Hand expressed concern with the process for reviewing special contract proposals under Tariff C.S.-IRP (Contract Service Interruptible Power) in 30-day filings. He contended this portion of the tariff is not in the public interest and should be removed. He explained that because virtually all special contracts provide the utility customer a discounted rate, which utilities routinely request be treated confidentially, such contracts fall within the "prohibited filings" described in 170 IAC 1-6-4 with respect to 30-day filings. He asserted that 30-day filings are intended for "noncontroversial" submissions and that contracts under this portion of the tariff can easily become controversial. Mr. Hand recommended removal of the phrase "under the 30-day filing procedures" from Tariff C.S.-IRP and Tariff C.S.-IRP2.

(d) __Tariff Terms and Conditions 11 and 12.__ Mr. Hand recommended removal of language currently in "Company's Liability" in Term and Condition 11 and denial of the proposed addition of similar language to "Customer's Liability" in Term and Condition 12. He stated the language is overreaching, shifts additional risks and responsibilities onto I&M's customers and provides no meaningful guidance to consumers, who generally do not claim to be experts in electric safety, and therefore reasonably expect I&M to fulfill its assigned duty to provide safe and reliable electric utility service as a regulated public utility. He asserted that given I&M's utility duties and expertise, its customers should not be asked to shoulder responsibility for protecting themselves, their families, and their homes from damage, injury or loss if the utility fails to meet its duty to provide safe and reliable electric utility service to the public.

(e) __Tariff Term and Condition 16.__ Mr. Hand recommended the Commission reject I&M's proposed Term and Condition 16 language "[as] specified by the Company," arguing that it will give unilateral control to I&M regarding where its facilities and equipment will be placed on private property.

(f) __Tariff Terms and Conditions 12 and 17.__ Mr. Hand recommended rejection of I&M's proposed change to Terms and Conditions 12 and 17 providing I&M additional discretion to disconnect customers without notice.

(g) __New Tariff Option to Tariff R.S.-OPES (Residential Off-Peak Energy Storage).__ Mr. Keen testified as to the OUCC's concerns regarding I&M's proposed PEV program under new Tariff R.S. – OPES/PEV including: (1) the use of the term "Experimental;" (2) how I&M defines and categorizes Electrical Vehicle Support Equipment ("EVSE"); and (3) a potential requirement that only specific PEVs can participate in the program.

(3) __Industrial Group Case-in-Chief.__ Mr. Dauphinais opposed I&M's proposed new terms and conditions for non-residential customer deposits in Rule 4 of its Terms and Conditions of Service. He characterized the proposed provisions as "too draconian" for non-residential customers and stated they give too much discretion to the Company. He also asserted that the proposed provisions are inconsistent with past Commission orders regarding electric utility customer deposits. Mr. Dauphinais recommended that the non-residential customer portion of the Company's proposed Rule 4 be predicated on the assumption that new applicants and existing customers are creditworthy, and that a security deposit should only be required where a lack of creditworthiness is determined through payment delinquency or verifiable conditions demonstrating potential insolvency. He further recommended that it incorporate the protections to which residential customers are entitled under 170 IAC 5-1-15, including: (1) written notice of the precise facts upon which the Company bases its decision; (2) an opportunity to rebut those facts and appeal the Company's determination; (3) payment of interest at a rate commensurate with the length of withholding; and (4) review of the basis upon which any deposit is withheld on a periodic basis not to exceed twenty-four (24) months, and refund upon the determination of creditworthiness. He stated it should also minimize the discretion given to the Company to better ensure an equitable and non-discriminatory determination of customer creditworthiness. Finally, Mr. Dauphinais testified that in all instances where a security deposit is required, a letter of credit should be permitted as an alternative to a cash deposit.

(4) **I&M Rebuttal.**

(a) **Employee Discounts.** Mr. Chodak testified on rebuttal that the OUCC's recommendation to disallow a long-standing employee discount is unjustified. He stated the employee discount is a modest part of I&M's overall remuneration package and, as a tax-free fringe benefit, costs less from a ratemaking perspective than alternative forms of compensation. He noted that I&M regularly benchmarks its total compensation and it is commensurate with the Company's peers.

(b) **New Senior Citizen Tariff.** Mr. Hix responded to Mr. Hand's concerns regarding the proposed Optional Senior Citizen Tariff. First, he noted that I&M has successfully offered a similarly structured tariff in its Michigan jurisdiction for more than 30 years. He testified that I&M found that this new optional tariff offering was quite popular with many senior citizens in the former Three Rivers Rate Area in Michigan after it was offered there in 2010. He explained that this popularity in Michigan, along with a desire to assist I&M's most vulnerable customers, prompted I&M to make a similar offering in this proceeding for its Indiana senior citizens. He showed that I&M already is well versed in explaining to customers how the tariff works and the potential for higher monthly bills should they exceed 1,000 kWh during a billing period. He noted that very few issues have arisen with respect to the senior citizen tariff in Michigan, and all of the issues were satisfactorily resolved.

Regarding Mr. Hand's concern that customers choosing service under this optional tariff are locked in for one year, Mr. Hix explained that this provision merely reflects I&M's general policy with regard to tariff migrations (see Terms and Conditions of Service 1). However, to alleviate the OUCC's concern, I&M proposed a modification to the proposed tariff such that customers that migrate to the tariff and wish to return to another residential tariff in less than one year may do so, so long as they remain at the tariff that they migrate to for a minimum of twelve months.

Mr. Hix clarified Mr. Roush's testimony regarding the revenue neutrality of Tariff R.S.-SC, explaining that it was designed to be revenue neutral in the sense that a customer consuming 1,000 kWh in a billing period (the average monthly usage by a residential customer) would pay the same amount under either Tariff R.S.-SC or the standard residential tariff. While it is true that I&M does not know how many customers may opt for service under the proposed optional tariff, Mr. Hix explained that it is reasonable to expect that only those customers that realize a net benefit will opt for service under the optional tariff. He stated the Company fully expects that implementing Tariff R.S.-SC will result in a reduction of revenue rather than an increase in revenue as suggested by Mr. Hand. Mr. Hix noted the potential loss of revenue resulting from Tariff R.S.-SC is not reflected in I&M's cost of service analysis.

Mr. Hix disagreed with Mr. Hand's recommendation that I&M work with the OUCC to develop promotional material and customer safeguards regarding the proposed Tariff R.S.-SC as well as an annual report requirement. He explained that the proposed tariff with the slight modification mentioned above should alleviate the OUCC's concerns that I&M's senior citizens may be confused about how the proposed tariff works and that they are locked-in for one year. He stated there is no reason to delay I&M's senior citizens access to the proposed discounted tariff nor justification to impose the cost of producing an annual report. Mr. Hix noted that I&M

meets with the OUCC from time to time and has no objection to responding on an informal basis should the OUCC have questions regarding the implementation of this optional tariff, including providing reasonable information such as participation levels, usage and revenues.

(c) Tariff Terms and Conditions 11 and 12. Mr. Hix responded to Mr. Hand's recommendation to remove language from Terms and Conditions 11 and 12. He described the language at issue, which explains the customer's responsibility to provide and maintain suitable protective devices on customer-owned equipment. Mr. Hix explained that the purpose of including this language in Term and Condition 12 is merely to provide additional clarity and transparency for I&M's customers, not to impose additional risks or responsibilities onto any customers. He stated the language that requires customers to be responsible for maintaining suitable protective devices due to fluctuations or irregular supplies of energy is standard in the electric utility industry and has not been a source of complaints or concerns expressed by I&M's customers.

(d) Tariff Term and Condition 16. Mr. Hix explained that the proposed language in Term and Condition 16 merely clarifies a longstanding provision that the utility has final say in the location of the facilities required to provide service to the customer and is essentially a reiteration of the same provisions included in Term and Condition 9. He explained that this provision also is standard in the electric utility industry. He noted I&M employs good engineering practices at the lowest reasonable cost when it plans service extensions and Mr. Hand's recommendation to abandon these long standing principles would necessarily increase I&M's cost to serve all customers and create issues that would cause numerous operational and/or safety problems.

(e) Tariff Terms and Conditions 12 and 17. With respect to I&M's proposal to add clarifying language to Terms and Conditions 12 and 17 regarding disconnection of service, Mr. Hix explained that the intent of this language is to make it clear that I&M may disconnect a customer in the event their service is detrimentally affecting I&M's general service. He explained that it is necessary to ensure that all of I&M's customers continue to receive adequate, safe and reliable electric service. He noted that the existing language from Term and Condition 17 makes it clear that customers may not use equipment in such a manner as to interfere with I&M's responsibility of supplying service to I&M's other customers. He explained that a need for an immediate disconnection would be a rare circumstance, but could certainly occur. He gave the example of a customer's equipment that is experiencing catastrophic failures (such as a failure of an arc furnace or damaged customer owned distribution equipment) that are causing detrimental issues on the I&M system, necessitating immediate disconnection.

(f) Tariff C.S.-IRP and Tariff C.S.-IRP2. Mr. Hix testified on rebuttal that the issue of Mr. Hand's recommended removal of the Commission-approved language in Tariffs C.S.-IRP and C.S.-IRP2 regarding "30-day filing procedures" was fully litigated in Cause No. 43878. He stated it is not necessary to re-litigate the issue and Mr. Hand's recommendation should again be rejected.

(g) New Tariff Option to Tariff R.S.-OPES (Residential Off-Peak Energy Storage). I&M offered revisions to the proposed language of Tariff R.S.-OPES/PEV to alleviate the OUCC's concerns raised in Mr. Keen's testimony. Specifically, with regard to the EVSE Option language, I&M suggested replacing "Company approved" with "UL Certified SAE J1772 compliant Level II." Mr. Hix testified that similar language would also be added to the contract required for those customers choosing the EVSE Option. I&M also agreed with Mr. Keen that the tariff language should better identify qualifying PEVs in the Availability Statement of the tariff. I&M suggested that the following statement be added to the end of the first paragraph of the Availability of Service statement: "For purposes of service under this tariff, a qualifying PEV is any SAE J1772 compliant motor vehicle registered to operate on public highways in the State of Indiana and is propelled by an electric motor and batteries that can be charged by an external source of electricity."

In response to Mr. Keen's concern with the use of the term "experimental" in the title of the EVSE option, Mr. Hix testified that the EVSE option is designed to allow I&M to gather data and that a date when the Company has obtained sufficient load research data so as to warrant termination of the EVSE Option is not currently known. Regarding Mr. Keen's concern that "there is no way to determine whether this tariff will last for a day, a week, months or years," Mr. Hix explained that the fact that at some point in the future the $2,500 incentive may come to an end in no way harms any customer that has invested in a PEV charging station or a PEV. He stated proposed Tariff R.S.-OPES/PEV can exist and provide a lower cost off-peak energy option to PEV and/or PEV charging station owners with or without the EVSE Option. Mr. Hix testified that, to his knowledge, the concern noted by the OUCC has not arisen regarding the approximately 750 Indiana customers that have already invested in ETS equipment. Given this, he opined that it does not seem necessary to take a different view of the tariff with regard to the addition of PEV charging stations as equipment qualifying for service under the tariff.

Mr. Hix explained that it is not clear to I&M what the OUCC's concern is regarding the collection and use of PEV charging station usage data. He provided a description of what the proposed tariff language provides and explained that PEV charging station load research data will be obtained and processed in the same manner as I&M's other load research program data is currently obtained and processed. Mr. Hix testified that I&M believes the proposed tariff adequately addresses data collection plans and needs.

(h) <u>Tariff Term and Condition 4.</u> Mr. Hix testified that I&M is willing to accept many of Mr. Dauphnais' suggestions to help clarify the Company's nonresidential deposit policy and make the deposit policy more transparent to customers to better ensure that the policy is applied in a nondiscriminatory manner. He submitted revised language for Term and Condition 4 and provided justification with respect to the areas where the Company did not agree with Mr. Dauphinais' suggested changes.

(5) <u>Commission Discussion and Findings.</u> No party opposed I&M's proposed reorganization of its tariff book, nor did any party oppose other proposals presented by Mr. Hix including those regarding its Equal Payment Plan, DNI fee, and Reconnection fee. Similarly, no party opposed I&M's proposed modifications to Tariffs O.L., E.C.L.S., M.G.S. and S.G.S., Rider AFS, and I&M's proposed closing or cancellation of Tariff E.H.S. and Riders E.C.S. and E.P.C.S. Based upon the evidence of record, the uncontested proposals for I&M's tariffs, riders, rules and regulations are approved as proposed by I&M. With regard to the contested tariff items, we will address each issue individually.

(a) **Employee Rate for Tariff R.S.-TOD2.** The record shows that I&M's long-standing employee discount is a tax free benefit and a cost-effective way to create a competitive total compensation package for employees. As indicated by Mr. Chodak during cross-examination, I&M includes the employee discount in its total compensation that it benchmarks, and the discount encourages I&M employees to live in I&M's service territory and provide better service. We find that I&M's employee discount is a reasonable measure to attract and retain employees.

(b) **New Senior Citizen Tariff.** We find that the proposed Optional Senior Citizen Tariff inappropriately singles out a class of customers without a sufficient basis. To the extent that senior citizens need financial assistance to pay utility bills, I&M already offers need-based assistance. I&M has failed to demonstrate why this particular class of ratepayers should be treated differently than any other. Therefore, we reject I&M's proposed Optional Senior Citizen Tariff.

(c) **Tariff Terms and Conditions 11 and 12.** We agree with Mr. Hix that Mr. Hand's recommendation with respect to Terms and Conditions 11 and 12 would inappropriately place liability on I&M for circumstances over which the Company has little or no control. The record reflects that fluctuations or disturbances, including single-phasing conditions, may be created by storms, auto accidents, or third-party contacts that are outside the control of the utility. To make the Company responsible for the protection of customer-owned equipment as a result of such disturbances on the supply of electric energy is unreasonable. Indiana's other large investor-owned electric utilities include language with similar intent in their Commission approved Terms and Conditions of Service. Therefore, we reject Mr. Hand's recommendation.

(d) **Tariff Term and Condition 16.** We agree that I&M's proposed language in Term and Condition 16 is reasonable and standard in the electric utility industry. Mr. Hix presented evidence that Indiana's other large investor-owned electric utilities include language with similar intent in their Commission approved Terms and Conditions of Service. Mr. Hand presented no evidence of prior cases or problems with this existing tariff language to support his position. We agree with I&M that the proposed language change will add needed clarity and will ensure facilities are located consistent with good engineering practices. We therefore reject Mr. Hand's recommendation.

(e) **Tariff Terms and Conditions 12 and 17.** With respect to Mr. Hand's concerns with I&M's proposed language in Terms and Conditions 12 and 17, we find the provisions are reasonably necessary to ensure that all of I&M's customers continue to receive adequate, safe, and reliable electric service and are consistent with existing provisions in I&M's tariff. Therefore, we accept I&M's proposed changes.

(f) **Tariff C.S.-IRP and Tariff C.S.-IRP2.** Although I&M proposed no changes to these tariffs, Mr. Hand proposed that the Commission remove language previously approved in I&M's last rate case and upheld by the Commission in a litigated case thereafter. The language at issue was the subject of the Commission's February 2, 2011 decision in Cause No. 43878, which involved a dispute over the impact of language in the Commission's recently revised 30-day filing rule in 170 IAC 1-6-4(8) on tariff language that permitted I&M to submit redacted copies of proposed special contracts to the Commission for approval as 30-day filings, with confidential provisions submitted to the Commission under seal, under a standing preliminary finding that pricing information required to support the approval of special contracts be protected from public disclosure as confidential trade secrets, pending a final determination by the Commission.

170 IAC 1-6-4(8) prohibits a utility form using the 30-day filing rule for any filing for which the utility wants confidential treatment for all or part of the filing. Our Order in Cause No. 43878 granted I&M a unique exception to this rule. However, we no longer agree that such an exception is appropriate. Special contracts typically involve price reductions for specific customers and can result in a shifting of cost recovery between customer classes. As a result, special contract cases have the potential to be contested, and a docketed proceeding provides a more adequate level of process for the parties and the Commission to address such issues. Therefore, I&M shall remove the language authorizing confidential submissions to be made in 30-day filings from I&M's proposed Tariff C.S.-IRP and Tariff C.S.-IPR2.

(g) New Tariff Option to Tariff R.S.-OPES (Residential Off-Peak Energy Storage). While we support the changes to Petitioner's Taris R.S.-OPES to allow use by owners of electric vehicles, we do not believe it is appropriate to grant Petitioner cost recovery for an electric vehicle program without that issue being fully explored through a separate proceeding, such as those we have conducted for other utilities with PEV pilot programs. Therefore, we deny Petitioner's proposed tariff.

(h) Tariff Term and Condition 4. During cross-examination, Mr. Hix clarified several aspects of Term and Condition 4. First, he acknowledged that the provisions in the rule that reference a cash deposit also apply if instead of cash a surety bond or a letter of credit has been posted. He further clarified that the notice provided to the customer pursuant to paragraph 5 of Petitioner's Exhibit WWH-R3 would be some form of written documentation, either electronic or otherwise. With respect to paragraph 6, Mr. Hix indicated the Company's intent was that if one account of a customer becomes delinquent, the amount of the deposit required would be based on that one account, rather than the total accounts for that customer. Finally, Mr. Hix agreed that the last paragraph in Petitioner's Exhibit WWH-R3 provided two alternative conditions that if met, I&M would refund a deposit. With the proposed language additions and or changes to proposed Term and Condition 4 described in Mr. Hix's rebuttal testimony and Petitioner's Exhibit WWH-R3, and with the clarifications provided during cross-examination, we believe that Mr. Dauphinais' concerns regarding this tariff have been satisfactorily addressed. Accordingly, we approve the proposed tariff including the revised language recommended in Petitioner's Exhibit WWH-R3.

15. Transmission Service.

A. I&M Case-in-Chief. I&M proposes that the following transmission-related cost components related to I&M's obligations as a PJM Load Serving Entity ("LSE") be included in basic rates for transmission service: Network Integration Transmission Service ("NITS"), pursuant to PJM Open Access Transmission Tariff ("OATT") Attachments H-14 and H-20; Firm and Non-Firm Point-to-Point ("PTP") Revenues, pursuant to PJM OATT Attachment H-14; Transmission Owner Scheduling, System Control and Dispatch Service, pursuant to PJM OATT

Schedule 1A; PJM Expansion Cost Recovery Charges ("ECRC"), pursuant to PJM OATT Schedule 13; and AEP RTO Start-up Cost Recovery Charges, pursuant to PJM OATT Attachment H-14. Mr. Roush discussed each of the foregoing charges. He explained that the Company's transmission costs should be based upon the charges under the PJM OATT for a number of reasons, including: (1) I&M no longer has exclusive control over its transmission costs because of its membership in PJM; (2) comparability in transmission charges with other Indiana customers in the AEP Zone, who pay the FERC approved OATT charges; (3) proper separation of I&M's costs to provide retail electric service as a LSE from I&M's costs and wholesale revenues as a Transmission Owner ("TO"); and (4) I&M is charged for transmission service regardless of facility ownership. He explained that under the Company's proposal, the rates Indiana customers pay for retail electric service will better reflect the transmission service costs that I&M incurs as their LSE. He said the Company's entire traditional embedded cost of transmission, net of the revenues the Company receives from PJM as a TO, have been removed from the Company's revenue requirement in this proceeding, as shown in Petitioner's Exhibit A-1. He added that, as proposed by I&M, the basic rates for retail electric service will no longer directly reflect the cost of I&M's transmission investment, I&M's transmission operation and maintenance expense and all other I&M-specific transmission-related costs.

B. <u>OUCC Case-in-Chief.</u> Mr. Eckert recommended the Commission continue to embed revenue requirements associated with the use of I&M's transmission system for the provision of Indiana retail service. In his view I&M's proposal would result in a fundamental shift in Indiana ratemaking practices. He testified that he is unaware of any electric utility in Indiana that follows the practice proposed by Petitioner.

C. <u>Industrial Group Case-in-Chief.</u> Mr. Dauphinais raised a concern that I&M's proposal could be viewed as a request for the Commission to cede its ratemaking authority over the transmission component of I&M's Indiana-jurisdictional retail revenue requirement to FERC. After explaining this concern, Mr. Dauphinais concluded that it appears I&M's proposal in this proceeding helps rather than harms I&M's Indiana retail customers. Mr. Dauphinais recommended if the Commission accepts I&M's proposal, the Commission should make it clear that it is only accepting I&M's proposal in the context of the specific facts presented in this proceeding and that in no way is the Commission ceding its ratemaking authority over the transmission component of I&M's bundled retail electric rates in Indiana by accepting I&M's proposal in this proceeding.

D. <u>I&M Rebuttal.</u> Mr. Roush clarified that in this proceeding the Company is not proposing to track its transmission costs in the PJM Cost Rider as suggested in Mr. Eckert's description of I&M's proposal. He explained that I&M proposes to include in its basic rates for transmission service the specified transmission-related cost components related to I&M's obligation as a LSE. However, Mr. Roush conceded that Mr. Eckert's misinterpretation of I&M's proposal is a good idea. He stated that if I&M were to track transmission costs in the PJM Cost Rider, it would ensure that customers pay rates that reflect no more or less than the actual cost of transmission service. Mr. Roush reiterated that the Company's proposal regarding the OATT adjustment is appropriate ratemaking. He explained that the Company supported the calculation of and rationale for the adjustment in its pre-filed direct testimony, exhibits and workpapers. Further, the Company discussed, made presentations, and followed up in writing on this topic as part of the audit process and in response to discovery. He explained that should the

Commission approve the Company's proposal, the amount of the adjustment will change as a result of any other changes to the Company's case as filed, since the values are directly calculated from the class cost-of-service study. He stated that if the Commission were to reject the Company's proposed adjustment, the revenues and expenses under the FERC-approved Transmission Agreement would remain in the cost-of-service as well as I&M's own transmission investment and costs and thus the Company's adjustment would be $0.

E. **Commission Discussion and Findings.** We accept Petitioner's proposal to include the FERC-approved OATT charges in basic rates. We have reviewed the level of those transmission costs and find that the record supports the conclusion that Petitioner's proposal will better reflect the transmission service costs that I&M incurs and is appropriate ratemaking treatment. This finding is based on our review of the evidence and should not be interpreted to mean that we relinquish our ratemaking authority over the transmission component of I&M's retail electric rates in Indiana.

16. Timing of Next Rate Case.

A. **South Bend Case-in-Chief.** Reed W. Cearley testified that he believes it is in I&M's and its customer's best interest for this Commission to require I&M come back before this Commission for another rate case within 3 years.

B. **I&M Rebuttal.** Mr. Krawec testified that I&M does not agree that it should be required to come back before this Commission for another rate case within precisely 3 years. He stated I&M recognizes that there may be drivers causing I&M to need to file base rate cases on a regular basis in the upcoming years. Mr. Krawec testified that Mr. Cearley's position, however, does not take into account that a utility should be allowed to file a rate case and present evidence if it feels it needs a rate increase.

C. **Commission Discussion and Findings.** Our task in this proceeding is to establish just and reasonable rates to replace those found to be unjust and unreasonable. The preparation and processing of a general rate case is a substantial undertaking, requiring significant time and resources of the utility, the Commission and other parties. I&M is capable of assessing its ongoing operations and is well suited to make its own decisions as to when it will initiate its next general rate case. Further, the governing statutory framework does not limit the initiation of a rate case to the utility. Such proceedings may be initiated by Intervenor South Bend, other parties, or the Commission. Accordingly, we find that Mr. Cearley's proposal should be rejected.

17. Confidentiality. Petitioner made two motions for protective order, all of which were supported by affidavit or testimony showing documents to be submitted to the Commission were trade secret information within the scope of Ind. Code §§ 5-14-3-4 and 24-2-3-2. In addition, SDI filed an Unopposed Motion for Preliminary Protection of Claimed Confidential and Proprietary Information for which Petitioner provided a supporting Affidavit. The Presiding Officers issued a Docket Entry on October 4, 2011, May 23, 2012 and May 29, 2012, respectively, finding such information to be preliminarily confidential, after which the information was submitted under seal. We find all such information is confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, and is exempt from public access and disclosure by the

Commission.

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

1. Petitioner is authorized to adjust and increase its rates and charges for electric utility service to produce an increase in total operating revenues of approximately $85 million in accordance with the findings herein. Petitioner's rates and charges shall be designed to produce total annual Indiana Jurisdictional operating revenues of $1,420,015,206, which are expected to produce annual net operating income of $167,197,805.

2. Petitioner is authorized to place into effect rates and charges in accordance with the findings herein for bills rendered for retail electric service on and after the effective date of this order.

3. Petitioner shall file tariffs with the Electric Division of the Commission, prior to placing into effect the rates and charges authorized herein and in conformity with the Commission's rules for filing of utility tariffs

4. Petitioner is authorized to place into effect for accrual accounting purposes the revised depreciation accrual rates as proposed by Mr. Davis.

5. The accounting authority sought by Petitioner is approved in accordance with Findings No. 7(A)(1)(d) (authority to defer return on Cook Unit 1 turbine) and Finding No. 9(C)(5)(f) (approving a Major Storm Damage Restoration Reserve).

6. Petitioner is authorized to implement the Capacity Tracker in accordance with Finding No. 9(B)(2)(e).

7. The information filed by Petitioner in this Cause pursuant to its Motions for Protective Order is deemed confidential pursuant to Ind. Code §§ 5-14-3-4 and 24-2-3-2, is exempt from public access and disclosure by Indiana law, and shall be held confidential and protected from public access and disclosure by the Commission.

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

ATTERHOLT, BENNETT, LANDIS, MAYS AND ZIEGNER CONCUR:

APPROVED: FEB 13 2013

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

Brenda A. Howe

Brenda A. Howe
Secretary to the Commission