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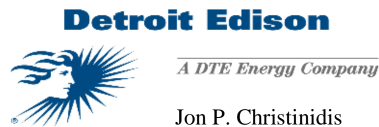

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June 22, 2011

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
6545 Mercantile Way
Lansing, Michigan 48909

Re: In the matter of the application of The Detroit Edison Company for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority
Case No. U-16472 (Paperless e-file)

In the Matter of the Application of The Detroit Edison Company for Approval to Defer Certain Pension and Post-Employment Benefits Expense for Future Amortization and Recovery
Case No. U-16489 (Paperless e-file)

Dear Ms. Kunkle:

Attached for electronic filing in the above-captioned matter is The Detroit Edison Company's Reply Brief. Also attached is a Proof of Service.

Very truly yours,

Jon P. Christinidis

JPC/kbk
Attachments
cc: Service List

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of THE DETROIT EDISON COMPANY for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority	)	Case No. U-16472
In the matter of the application of THE DETROIT EDISON COMPANY for authority to defer certain pension and post-employment benefits expenses for future amortization and recovery.	)	Case No. U-16489 (Paperless e-file)

THE DETROIT EDISON COMPANY'S REPLY BRIEF

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Dated: June 22, 2011

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I. INTRODUCTION.

On June 3, 2011, The Detroit Edison Company ("Detroit Edison," "Edison" or the "Company") filed its Initial Brief in these cases. Initial briefs were also filed by Staff, the Association of Businesses Advocating Tariff Equity ("ABATE"); the Attorney General ("AG"); the Detroit Edison Alliance of Retirees ("DEAR"); Energy Michigan; the Detroit Medical Center ("DMC"), Henry Ford Health System ("HFHS"), William Beaumont Hospital ("Beaumont") and Trinity Health-Michigan (collectively, the "Hospitals"); the Kroger Company ("Kroger"); the Michigan Community Action Agency Association ("MCAAA"); the Michigan Environmental Council ("MEC") and National Resource Defense Council ("NRDC"); Utility Workers Local 223 ("UWL 223"); and Wal-Mart Stores East, LP, and Sam's East, Inc. (collectively, "Wal-Mart").

This reply will focus on Staff's Initial Brief, since that brief sets forth the most comprehensive discussion of the issues in this proceeding. To avoid repetition and disjointed discussions, Edison will collectively address the other parties' related arguments in the context of replying to Staff. For purposes of clarity and completeness, Edison will generally follow the order of its Initial Brief, and will at times note issues that are resolved by agreement. Edison will avoid belaboring or repeating matters, and relies on the content of its Initial Brief and its Attachments,[1] along with its testimony and exhibits and incorporates the same as if restated here. Edison will attempt to be thorough, but notes that it is not (nor is it required to be) clairvoyant, and objects to the extent any party's Initial Brief does not articulate or explain a position to which Edison can respond. Furthermore, the lack of a discussion by Edison to separately address every issue or position suggested or inferred by any party should not be deemed to constitute an agreement by Edison.

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[1] Unless otherwise indicated, references to Attachments are to the Attachments accompanying Edison's Initial Brief.

II. BACKGROUND AND SUMMARY OF MAJOR ISSUES.

Edison previously explained that its lower revenues and higher expenses, and thus its corresponding need for rate relief, are based predominantly on economic events that are beyond Edison's control (Edison Initial Brief, pp 9-13).[2] [3] Edison is keenly aware of the poor economy's effects on its customers, and therefore continues to aggressively pursue opportunities to reduce costs and improve performance as much as possible, while still providing safe and reliable service to its customers and meeting numerous legal requirements. Edison also supports Michigan's economy, and provides other economic benefits, as a major employer and taxpayer in the communities it serves. Although Edison is engaging in a number of efforts to reduce its costs and minimize the impact of economic and financial events, Edison still faced a jurisdictional revenue deficiency of approximately $443 million (approximately $444 million on a total electric basis) (6 T 342, 355; Exhibit A-8, Schedule A1). After reviewing Staff's various positions, however, Edison has recognized two changes put forth by Staff in its April 1, 2011 filing; (1) the more recent update to the Company's pension and other post employment benefit ("OPEB") costs (11 T 2267) and (2) recognition of contract renewal associated with one of Edison's wholesale for resale customers, Detroit Public Lighting Department (11 T 2348;

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[2] The continued weak economy has significantly reduced Edison's sales revenues in each customer class. Edison's service area sales for the projected test year ending March 31, 2012 are forecast to be 48,466 GWh. Service area sales have not been below 50,000 GWh since 1998. Edison also lost a significant amount of its full service load as Electric Choice volumes increased from approximately 1,500 GWh in 2009 to 5,000 GWh (at the statutory 10% cap) in 2010. Moreover, certain Wholesale for Resale customers (Michigan municipal and cooperative utilities that purchase power supply from Edison under long-term contracts, for resale to Michigan retail customers) have contracts that will expire before the end of the projected test year in this case. These customers account for significant firm load on Edison's system, and only one of these contracts will be renewed after expiration - the Detroit Public Lighting Department contract, as indicated by Staff (11 T 2348; Exhibit S-11).

[3] The major reasons for Edison's need for additional revenue are: (1) the capital and operation and maintenance costs associated with environmental compliance; (2) costs associated with the operation and maintenance of Edison's electric generation plants and distribution system; (3) costs associated with employee pension and benefits; (4) costs associated with inflation; (5) capital costs associated with the addition of plant, including advanced metering infrastructure ("AMI"), safety and reliability of Edison's distribution and generation plants, and capacity upgrades; (6) the expiration of certain wholesale for resale contracts; and (7) increased taxes and capital structure costs.

Exhibit S-11). Based on these two adjustments, Edison now supports a jurisdictional revenue deficiency of approximately $357 million (approximately $361 million on a total electric basis).[4]

Staff recommends a revenue deficiency of $161,677,000 on a total electric basis (Staff Initial Brief, pp 4-5), which is more than the amount that Staff indicated previously (approximately $159 million; approximately $157.2 million a jurisdictional basis (Exhibit S-1, Schedule A1, column (e)). Edison agrees with and appreciates Staff's corrections, but Staff still suggests an unworkably low Total Electric revenue deficiency of approximately $161.7 million (without calculating a jurisdictional revenue deficiency). The necessary changes in addition to Staff's proposal are discussed in Edison's Initial Brief and below within the context of the related topic and are also contained in Edison's Reply Brief Attachment A and Attachment B.

III. TEST YEAR.

Edison previously discussed its historical and projected test years (Edison Initial Brief, pp 18-19). Edison proposes a projected test year of April 1, 2011 through March 31, 2012. Staff and AG agree (Staff Initial Brief, pp 6-7; AG Initial Brief, p 25), and no Intervenor disagrees, so the Commission should adopt that projected test year.

IV. RATE BASE.

Edison previously discussed its rate base (Edison Initial Brief, pp 19-21). Edison adopted Staff's April 1, 2011 filed testimony associated with the contract renewal of Edison's wholesale for resale customer Detroit Public Lighting Department (11 T 2348; Exhibit S-11), which results in Edison supporting a jurisdictional rate base of approximately $10.075 billion and approximately $10.146 billion on a total electric basis (Edison Initial Brief Attachment A, page 2).

[4] See Edison Initial Brief Attachment A, pages 1 through 5.

Staff supports a total electric rate base amount of $10.065 billion[5], stating: "Staff accepts the Company's methodology used to develop its Rate Base Projection. However, Staff's Rate Base calculation differs from the Company's calculation due to Staff's recommended adjustments to capital expenditures and accumulated depreciation provision and expense" (Staff Initial Brief, pp 7-8). There is no tangible disagreement in these cases about depreciation expense, however. Staff recommends an accumulated depreciation and amortization of $6,464,110,000[6], but agrees with Edison that "the depreciation rate reductions proposed in this rate case are preliminary and that they will need to be recalculated using the approved plant levels and composite rates in the Commission orders for the rate case and the depreciation case" (Staff Initial Brief, p 16). The Commission issued a depreciation order for Detroit Edison on June 16, 2011 in Case No. U-16117. The Order requires that "[t]he new depreciation rates and practices approved by this order shall take effect on the day after issuance of the final order in Case No. U-16472." (Case No. U-16117 Order dated June 16, 2011, p 16) Therefore, the ALJ in this proceeding need only recommend that the new depreciation rates for Edison set forth in Case No. U-16117 be implemented prospectively beginning the day after the rates take effect from the final Order issued in this proceeding.

Staff further states that: "As seen on Exhibit S-7, Staff adopted Detroit Edison's projected capital expenditures with two exceptions," concerning reliability capital expenditures and Advanced Metering Infrastructure ("AMI")/Smart Grid capital expenditures (Staff Initial Brief, p 9). The AG similarly, but more dramatically, proposes to reduce Edison's rate base to

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[5] Page 7 of Staff's Initial Brief erroneously states a rate base level of $10,059,000,000. The correct amount of $10,065,035,000 was identified in footnote 16, page 5 of Staff's Initial Brief and relates to Staff's adjustment associated with Edison's reliability capital expenditures (Staff Initial Brief, pages 8-9).

[6] Page 15 of Staff's Initial Brief erroneously states accumulated depreciation and amortization of $6,464,110,000. The amount does not reflect the impact on Staff's depreciation notes in footnote 20, page 6 of Staff's Initial Brief. See Edison Reply Brief Attachment A, page 3 which reflects the revised amount of $6,464,246,000.

$9,556,733,000, based on AG witness Mr. Coppola's[7] proposed $479,700,000 reductions in capital expenditures, and AG witness Mr. McGarry's $89.76 million proposal to defer AMI capital costs as regulatory assets (AG Initial Brief, pp 25-28). Staff's and AG's proposed reductions in Edison's capital expenditures lack merit for the reasons discussed in Edison's Initial Brief, and further discussed below in specific context where the justifications for Edison's expenditures are best understood.

Staff supports $514.8 million of Working Capital (Staff Initial Brief, p 16), which is $77.6 million less than the $592.4 million of Working Capital that Edison supports (6 T 342, 344, 346; Exhibit A-9, Schedule B1, column (c)). The difference is due primarily to Staff's reduction of Edison's forecasted working capital by $67.7 million related to Edison's trust investments for non-qualified benefit plans.[8] Edison disagrees because its benefit plans are designed to retain skilled executives and the non-qualified plans are a component of its total compensation program, as further discussed in Edison's Initial Brief and below. If, however, the Commission were to agree with Staff that the program assets should be removed as a working capital requirement, then the related liability of $63.6 million in Edison's working capital forecast must also be removed to ensure that the complete working capital requirement for the non-qualified plans is eliminated (7 T 1137). Staff disagrees, without analysis, contending only that "the Company did not provide adequate documentation to Staff to support its claim that a corresponding liability was included in the rate case" (Staff Initial Brief, p 17). Staff's response is unpersuasive because Edison's position is supported by expert testimony on the record (7 T

[7] As explained in the Company's Initial Brief, Mr. Coppola lacks sufficient expertise to opine as to the necessity or prudence of numerous Edison capital and O&M expenditures – he simply knows nothing about, by way of example and not limitation, the maintenance and operation of electric power plants (10 T 1901-1904).

[8] Staff describes the remaining difference as "a disallowance $11.6 million deferred gain from the MGM land sale in 2005, and a disallowance of $1.7 million in deferred compensation consistent with the disallowance in O&M expense" (Staff Initial Brief, p 16).

1137), which is sufficient to sustain a decision by the Commission.[9] Moreover, Staff had adequate time to address any concerns, as the offsetting liability entry was discussed in the Company's rebuttal testimony, and to recognize a one-side entry is patently unfair. Finally, there is a fundamental regulatory principle that total assets must equal total liabilities, as Edison discussed previously (Edison Initial Brief, pp 20-21).[10]

ABATE suggests that, in Edison's next rate case, working capital should not be determined using the balance sheet approach that the Commission ordered in Case No. U-7350, but instead should consist solely of certain assets and a Cash Working Capital ("CWC") component that is calculated through a lead/lag study (ABATE Initial Brief, pp 3-5). ABATE claims that the balance sheet method of measuring working capital "is outdated and not used by any other regulator." ABATE witness Selecky's discussion of this issue makes no reference to the modernity of the balance sheet method and only suggests that he is not aware of any other rate setting jurisdictions using the balance sheet method. (9 T 1467) While admittedly the balance sheet method was adopted by the Commission over 25 years ago, the Commission selected the balance sheet method as a superior alternative over the lead/lag study alternative, and was even recommended by ABATE. (7 T 1140-1, Case No. U-7350 Order dated June 11, 1985, p 5). Moreover, there is no evidence of the scope of Mr. Selecky's knowledge of the working capital practices of other jurisdictions, and the companies included in his Exhibit AB-6 refer to only a handful of States (Missouri, Illinois, Maryland and Idaho). Such a small sampling seems a far cry from the conclusion asserted by ABATE that the balance sheet method is not used by any other regulator. Finally, as explained by Company witness Ms. Uzenski, Mr.

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[9] *Great Lakes Steel v Public Service Comm*, 130 Mich App 470, 481; 334 NW2d 321 (1983).

[10] The discussion was in the context of Edison's request that if the Commission adjusts Edison's average rate base, then the Commission should make a corresponding adjustment to capitalization so that the approved rate base amount is supported by an equal capitalization amount. No party appears to disagree.

Selecky's attempt to compare the working capital produced by the balance sheet method for Edison is flawed as it improperly presumes that the Company's cash working capital component of working capital is overstated solely by reference to a simplistic comparison of the cash working capital of selected companies without regard to whether the companies cited include other costs in their total working capital. (7 T 1139) Thus, the underlying premise of Mr. Selecky's analysis is flawed and incomplete. Accordingly, ABATE's suggestion should be rejected in favor of continuing to determine working capital using the well-established balance sheet approach (7 T 1138-41).

V. CAPITAL STRUCTURE AND RATE OF RETURN.

Edison previously explained (Edison Initial Brief, p 21) that the Commission should adopt Edison's weighted after-tax rate of return of 6.865% (6 T 350; Exhibit A-11, Schedule D1, column (g), line 19), and that Staff adopted many of the Company's projections, so the only substantive issues affecting rate of return relate to Staff's incorrect estimates of the cost of long-term debt and credit facility fees, and the difference between the Company and Staff's proposed return on equity. Staff agrees about the issues, but separates a regulatory liability issue from the short-term debt discussion (Staff Initial Brief, pp 19-20).

A. Capital Structure.

Edison previously recommended and explained (Edison Initial Brief, pp 21-23) its need for a permanent capital structure consisting of approximately 51% debt and 49% equity, which is consistent with its capital structure in the 2009 test year, the Commission's January 11, 2010 Opinion and Order in Case No. U-15768, p 17, and the Company's plan for additional equity infusions and retained earnings to maintain at least 49% equity (6 T 177, 180, 191, 200; Exhibit A-11, Schedule D1). No party appears to disagree. Staff and Edison agree on a capital structure

balance of $10.146 billion, with Staff further observing that "Staff and the Company agree on the recommended balances for all components of the capital structure" (Staff Initial Brief, p 18).

Edison continues to face credit risk, significant business challenges, and challenges from Michigan's economy. Accordingly, the Commission should maintain Edison's 49% equity ratio, as Staff recognizes (Exhibit S-4, Schedule D1, p 1), and also increase Edison's ROE from 11% to 11.125%, as further discussed in section VI. C of Edison's Initial Brief and section V.C. below.

B. Debt Cost Rates.

1. Long-Term Debt.

Edison recommends a 5.58% weighted cost of long-term debt, which was determined using the net proceeds method for each issue, including the estimated financing cost of the new issues (Edison Initial Brief, p 24; 6 T 178, 196-97, 201, 350; Exhibit A-11, Schedule D2). Staff recommends a 5.53% cost of long-term debt (Staff Initial Brief, p 19). The record demonstrates that Staff under-estimated the term and forecasted interest rate for new debt to be issued. Staff assumed a 10-year term for new debt, but the majority of Edison's long-term debt issuances have a 30-year term. Edison assumed a 20-year term, which is the midpoint between 10 and 30 years. It was reasonable to assume that any new debt will be issued in a term longer than 10 years, with a correspondingly higher interest rate. Also, the average forecasted 10-year Treasury rate obtained by Staff was 3.29%, but as of April 11, 2011, the 10-year Treasury rate was 3.57%, and it is forecasted to rise throughout the year (6 T 204-205).

Staff maintains that its 10-year term is a reasonable estimate, asserting that "the Company's most recent debt issuances during 2010 were at the 10-year duration" and "the Company recently issued long-term debt in May 2011 at the 10-year duration at a coupon rate of 3.90%" (Staff Initial Brief, p 19). In fairness, Staff did not change its original forecast based on

recent information, however, Staff's reliance on non-record information to substantiate its position is misplaced,[11] and Staff's position is otherwise unpersuasive because numerous matters change throughout the course of a rate case. It is inappropriate to "cherry pick" isolated bits of new information to suggest that Edison's rate recovery should be lowered, while ignoring offsetting matters that favor a greater recovery for Edison.[12] For example, the record reflects Edison's understanding that the Michigan business tax ("MBT") would likely be replaced by a new corporate income tax in early 2012 (7 T 1025). That new corporate income tax was recently signed into law (2011 PA 38). Edison's analysis projects an increase in annual tax expense due to that new corporate income tax of approximately $12 million (7 T 1028-29). 2008 PA 286 discourages case updates due to the 12-month time frame for case completion.[13] Detroit Edison submits that the Company's due process rights would be violated if the Commission were to accept other parties' one-way (downward) updates. Therefore, the Commission should adopt Edison's recommended 5.58% composite long-term debt rate, but if Staff's position is adopted based on this non-record information, then Edison's recovery should be increased by at least another $12 million.

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[11] Const 1963, Art 6, § 28 requires the Commission's findings to "be supported by competent, material and substantial evidence on the whole record." The Administrative Procedures Act ("APA") precludes the Commission from making decisions based on non-record materials. MCL 24.276 provides: "Evidence in a contested case . . . shall be offered and made part of the record. Other factual information or evidence shall not be considered in determination of the case except as permitted under [MCL 24.277 concerning official notice of judicially cognizable facts and facts within the agency's specialized expertise]." Noncompliance with the APA is reversible error. *In re Public Service Commission Guidelines for Transactions Between Affiliates*, 252 Mich App 254, 267; 652 NW2d 1 (2002).

[12] Creating rates that recognize *reductions* in certain costs while ignoring the *increase* in other costs, violates the due process rights of utilities. The Michigan Supreme Court cited with approval the conclusions of a circuit court judge granting an injunction against such unlawful rates:

> "Certainly at first blush it would appear to anyone steeped in 'due process' considerations that it is grossly unfair to include certain items of decreased cost in rate determination while at the same time to exclude items of increased cost." *Michigan Consolidated Gas Company v Public Service Comm*, 389 Mich 624, 633; 209 NW2d 210 (1973).

[13] MCL 460.6a(3); January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, p 8.

2. Short-Term Debt.

Edison recommends $2.3 million of facility fees for the cost of related credit facilities, which are reflected separately as a component of Edison's operating costs (Edison Initial Brief, pp 24-25; 6 T 178, 195, 198, 201; Exhibit A-10, Schedule C11, line 4). Staff eliminates $1.1 million of facility fees, which Staff calls "commitment fees" (Staff Initial Brief, pp 20-21).

Staff contends that they did not exclude the $1.1 million in commitment fees based on a cost comparison of the old credit facility versus the new credit facility." Instead, Staff excluded the $1.1 million based on Edison's alleged "improper application of the Uniform System of Accounts pertaining to amortization of debt" (Staff Initial Brief, p 21). Staff's argument that Edison improperly reflected commitment fees as a component of the Company's operating costs is inconsistent with Staff's own position, later in its brief, that commitment fees should be included as part of O&M (Staff Initial Brief p 53). Staff should not be heard to complain about how Edison recorded commitment fees where Staff cannot even agree within itself on how to record them. Most importantly, however, this case is not about building a ledger. It is about setting just and reasonable rates. If an item is not recorded in the right place, then it should be moved, but that recording location is irrelevant to whether the item is a legitimate cost that Edison should recover in its rates. Besides, recording the item in O&M allows for the recovery of a fixed cost. When it is included as a component of the cost of short-term debt it is tied to a potentially floating balance as short-term debt goes up and down and could create the potential for over or under recovery.

The record reflects that Staff incorrectly excluded $1.1 million of credit facility fees associated with the continued amortization of upfront expenses of a terminated credit facility. The annual cost of the terminated credit facility was $4.28 million. The annual cost of the new credit facility, including amortization of the upfront fees from the terminated credit facility, is

$1.94 million, resulting in an annual savings of $2.34 million. Therefore, renewing and extending the credit facility was reasonable and prudent, and the $1.1 million of costs (See Reply Brief Attachment A, page 2) should be included in the cost of the credit facilities (6 T 205; Exhibit A-25, Schedules DJG-1 and DJG-2).

In the alternative, Staff suggests that the Commission adopt AG witness Mr. Coppola's suggestion to remove the credit facility fees from other income and deductions, and include them in the calculation of short-term debt (Staff Initial Brief, p 21). This would be improper because there is no short-term debt in the projected test period (6 T 206; Exhibit A-11, Schedule D1).[14]

Accordingly, the Commission should adopt Edison's forecasted cost of short-term debt of 1.00%, plus $2.3 million for the cost of related credit facilities in other income and deductions.

C. Return on Common Equity.

Edison previously explained (Edison Initial Brief, pp 25-35) Dr. Vilbert and Mr. Goshorn's recommendation that a just and reasonable Return on Equity ("ROE") for Edison's common equity capital is 11.125%. This recommendation would increase to 11.375% if the Commission does not renew Edison's Choice Incentive Mechanism ("CIM") (7 T 936), and should not be reduced due to Edison's Uncollectible Expense Tracking Mechanism ("UETM"), Storm Expense tracker, and Revenue Decoupling Mechanism ("RDM") (7 T 936-37, 963).

Dr. Vilbert estimated the ROE for each sample company using the risk positioning[15] and Discounted Cash Flow ("DCF") approaches. He then combined the ROE estimates from both models with the market value capital structure information and costs of debt and preferred stock

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[14] There is similarly no merit in Mr. Coppola's suggested addition of $60.9 million to short-term debt, since Edison's short-term financing comes primarily from short-term debt and the Renewable Energy Program ("REP") regulatory liability. If the balance of short-term debt were to be increased, then the REP liability would have to be reduced by the same amount (7 T 1147).

[15] The risk positioning approach is sometimes called the risk premium approach, and consists of analyses using the Capital Asset Pricing Model ("CAPM") and the Empirical CAPM ("ECAPM") (7 T 886).

for each sample company to compute each company's overall cost of capital (i.e., its after-tax weighted-average cost of capital, or "ATWACC").[16] This resulted in a sample average ATWACC for each cost of equity estimation method. He reported the cost of equity consistent with the sample's average estimated ATWACC as if the sample's average market-value capital structure had a 49% equity ratio, which is consistent with Edison's requested capital structure in this case. The best point estimate of the ROE is 10.75% for an electric company of average business risk and a capital structure with a 49 percent equity ratio; however, Edison has a higher risk than the average company in the electric sample because of the severe economic downturn in Michigan, as well as Company-specific reasons. Thus, Dr. Vilbert's recommended ROE is based on the financial risk inherent in a 49% equity ratio for Edison, the sample ATWACC estimates, and the relative risk of Edison compared to the sample (7 T 886, 888, 892, 915-18, 934-37).

Staff recommends a 10.15% ROE, within a ROE range of 9.85% to 10.35% (Staff Initial Brief, p 22). ABATE supports Staff's recommendation, but misstates it as 10.10% (ABATE Initial Brief, p 6).The AG recommends a 10.25% ROE (AG Initial Brief, p 21). These recommendations are understated due to sample selection and failure to make appropriate adjustments. In addition, both Staff witness Mr. Megginson and AG witness Mr. Coppola witnesses suggest an underlying belief that Edison has average risk relative to sample companies. To the contrary, the uncertainty in the capital markets, the more challenging Michigan economic environment, and the differences in financial risk for Edison as compared to sample companies

[16] The ATWACC is calculated as the weighted average of the after-tax cost of debt capital and the cost of equity. The ATWACC is commonly referred to as the weighted-average cost of capital ("WACC") in financial textbooks, and is a fundamental method used by financial economists to measure the cost of capital. The ATWACC is important because it allows an "apples to apples" comparison between the sample companies' cost of capital estimates and the cost of capital for Edison by eliminating differences in financial risk due to differences in capital structure. The ATWACC avoids inconsistencies that could arise from estimating the cost of equity for sample companies without considering differences in financial risk inherent in each company's capital structure (the higher the debt-to-equity ratio, the higher the financial risk, and the higher the cost of equity) (7 T 892-93, 943-47).

justifies an increase in the recommended ROE for Edison relative to the sample companies (7 T 964-65).

Dr. Vilbert explained that he selected a sample of 27 regulated electric utility companies in the same line of business as Edison. Mr. Coppola criticized Dr. Vilbert's sample for including companies classified as mostly regulated ("MR"). Dr. Vilbert responded by explaining that Mr. Coppola mischaracterizes the MR classification, and that he properly included MR companies in his sample. Dr. Vilbert elected to retain the MR companies in order to increase the sample size, and thereby reduce estimation error, which is particularly important in times of economic uncertainty. Mr. Coppola's sample is too small given the uncertainty in the capital markets (7 T 953-54).

Mr. Megginson's sample also becomes undersized upon the elimination of two companies (Allegheny Energy, Inc. and FirstEnergy Corp) that do not satisfy his own criterion of not being involved in a merger, buyout or major acquisition (7 T 954-55). "Staff agrees that an oversight occurred and the two companies should not have been included in Staff's proxy group" (Staff Initial Brief, p 27).[17] Staff also apparently agrees that its DCF and CAPM estimates should be adjusted upward due to the elimination of these companies from Staff's sample, but maintains: "However, taking these changes into account does not affect Staff's recommended ROE range of 9.85% - 10.35%, despite the Company's validity in pointing out the sampling error" (Staff Initial Brief, p 28). Edison appreciates Staff's candor regarding its sampling error, but maintains that the refinement of Staff's sample should result in an increase in Staff's recommended ROE, and that Staff's entire ROE analysis does not have a sound basis of sample companies.

[17] Portland General Electric and Great Plains Energy could also be eliminated from Mr. Megginson's sample because they made dividend cuts in the last five years (7 T 955).

Mr. Megginson, without explanation, also chose to exclude approximately 10 companies that appear to fit his criteria (7 T 956). Staff responds that its proxy group consists of publicly-traded "pure plays" in the regulated electric industries, asserting that Dr. Vilbert stated that this would be an ideal sample (Staff Initial Brief, p 28). Dr. Vilbert actually testified, however: "For Detroit Edison, the ideal sample would be **a large number** of companies that are publicly traded 'pure plays' in the regulated electric industries' (7 T 915. Emphasis added). The problem is that Staff's sample of 11 companies (9 after excluding Allegheny Energy, Inc. and FirstEnergy Corp) is too small given the uncertainty in the capital markets. Dr. Vilbert's 27-company sample properly reduces estimation error, which is particularly important in times of economic uncertainty (7 T 953-54).

Mr. Megginson placed substantial emphasis on credit ratings (11 T 2143-44), and excluded some companies from his sample due to differences in credit ratings. Dr. Vilbert disagreed with Mr. Megginson's decision to include only companies within two notches of Edison's credit rating. He explained that a credit rating is a measure of the default risk on a company's debt. Default risk measures the company's total risk, and not its systemic or non-diversifiable risk, which is risk that is relevant to shareholders (7 T 957-58). Moreover there is a mismatch between the credit rating of the holding company being used to estimate the ROE and the credit ratings used by Mr. Megginson which are based upon the weighted-average of the credit ratings of the holding companies' regulated subsidiaries. The result is that holding companies with credit ratings within two notches may be excluded while those not within two notches are included (7 T 956).

Staff responds that Dr. Vilbert also considered investment grade credit ratings in constructing his proxy group, and that the Commission expressed approval of Staff's approach and proxy group in Consumers Energy Company's ("Consumers") last electric rate case, Case

No. U-16191 (Staff Initial Brief, pp 28-29). Staff's characterization of Dr. Vilbert's use of credit ratings is inaccurate. He used credit ratings only to eliminate financially-distressed companies (companies with non-investment grade credit ratings) from his sample, but otherwise his sample selection procedures had nothing to do with the sample companies' credit ratings (7 T 916). Staff's reliance on Case No. U-16191 is misplaced because this Edison rate case must be decided on its own record.[18] Staff's response is also unpersuasive because there is no dispute about the general appropriateness of using a proxy group to estimate a company's ROE. The real problem is that Staff's proxy group is too small, as discussed in Edison's Initial Brief and above. Staff's *undue* emphasis on credit ratings was simply one cause of the sampling problem, which remains uncorrected.[19]

Mr. Coppola implied that Dr. Vilbert's inclusion of smaller companies in his sample could inflate ROE estimates because investors impute a higher risk premium for small companies (10 T 1824). Dr. Vilbert responded by explaining that this size premium is much more pronounced in micro-cap[20] companies. Dr. Vilbert's sample does not include any micro-cap companies. All of the companies in his sample have a market capitalization of at least $500 million. Moreover, Mr. Coppola reversed the implications of the size effect, which says that the

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[18] Const 1963, Art 6, § 28 requires the Commission's findings to "be supported by competent, material and substantial evidence on the whole record." The Administrative Procedures Act ("APA") precludes the Commission from making decisions based on non-record materials. MCL 24.276 provides: "Evidence in a contested case . . . shall be offered and made part of the record. Other factual information or evidence shall not be considered in determination of the case except as permitted under [MCL 24.277 concerning official notice of judicially cognizable facts and facts within the agency's specialized expertise]." Noncompliance with the APA is reversible error. *In re Public Service Commission Guidelines for Transactions Between Affiliates*, 252 Mich App 254, 267; 652 NW2d 1 (2002).

[19] Staff also apparently created a sample based on average credit ratings of holding company regulated subsidiaries, which is inconsistent with using the holding companies, which have different credit ratings than their subsidiaries, to estimate the cost of capital (7 T 956-67).

[20] Micro-cap companies have a market capitalization that does not exceed a few hundred million dollars. (7 T 959)

CAPM underestimates the cost of equity for small companies. Dr. Vilbert made no adjustment to the cost of equity estimates for the companies in his sample because of their size (7 T 959).

Messrs. Coppola and Megginson did not consider financial risk (risk shifted to equity holders from the use of debt in a company's capital structure) among the sample companies and Edison. This failure to consider Edison's financial risk leads to an inappropriate downward bias in their ROE estimates, since Edison has more debt than the average sample company (7 T 944-45).

Staff responds that its analysis properly considered financial risk and presented an "apples to apples" comparison because Edison's equity ratio is "likely above or equivalent to" the 48% average common equity ratio of the companies in Staff's sample (Staff Initial Brief, pp 29-30). However, as described above, Staff's proxy group suffers from limitations that bring into question the reliability of the sample. Dr. Vilbert's sample has a 58% average common equity ratio (Exhibit A-11, Schedule D6.4), which is substantially higher than Edison's common equity ratio. Dr. Vilbert explained that the higher the debt ratio (or correspondingly, the lower the equity ratio), the higher cost of equity for a given level of business risk (7 T 893). Staff does not refute this point, and based on Dr. Vilbert's proxy group, Edison has a much higher level of financial risk than the average sample company.

1. CAPM and ECAPM Estimates.

Dr. Vilbert developed risk positioning estimates based on the CAPM and on an empirical approximation to the CAPM ("ECAPM"). The CAPM is based on the idea that risk-averse investors demand higher returns for assuming additional risk, and higher-risk securities are priced to yield higher expected returns than lower-risk securities. The CAPM quantifies the

additional return, or risk premium, required for bearing incremental risk using (a) a risk free rate, (b) beta,[21] and (c) a market risk premium (7 T 919).

As a proxy for the CAPM's risk-free interest rate, Dr. Vilbert used the 15-day average yields on long-term (20-year) Treasury bonds, which was 3.5% for the period ending August 26, 2010 (7 T 920, 928).[22] Dr. Vilbert conducted four analyses using 6.5%, 7.0%, 7.5%, and 8.0% for the market risk premium ("MRP"). He explained that he would typically view an MRP of 6.5% over the long-term bond rate as reasonable, but under current market conditions (e.g., the effect of the increased volatility in the capital markets on the cost of capital, stressed and failing banks, and a serious concern of a double-dip recession), a 50 to 150 basis point increase in the MRP is on the low side of adjustments that might reasonably be made. Thus, an MRP of between 7.0% and 8.0% is more appropriate at this time (7 T 915, 920-22). Dr. Vilbert used a 0.71 average beta reported by Value Line Investment Survey ("Value Line"), and a 0.78 average beta reported by Bloomberg (7 T 887, 923-25).

Neither Mr. Coppola nor Mr. Megginson made an adjustment to the risk-free rate, despite the larger than average spread between government and corporate bond yields. Their failure to make adjustments to the risk-free rate produced cost of equity estimates from the CAPM that are artificially low. Even Mr. Coppola acknowledged that the "Federal Reserve continues to inject liquidity into the economy and to keep interest rates low" (10 T 1829). Mr. Megginson's workpaper, WP-KDM-50, shows that the 30-year bond yield is forecasted to increase by 58 basis

[21] Dr. Vilbert explained that the basic idea behind beta is that risks that cannot be eliminated by diversification in large portfolios matter more than those that can be eliminated by diversification. Beta is a measure of the risks that cannot be eliminated by diversification. It measures the "systematic" risk of a stock – the extent to which the stock's value fluctuates more or less than the average when the market fluctuates (7 T 922).

[22] Dr. Vilbert explained that long-term rates are the relevant benchmarks because short-term Treasury bill yields have been driven down to artificially low levels by the Federal Reserve's efforts to stimulate the economy. Risk positioning estimates using short-term Treasury bill yields as the risk-free interest rate are sometimes less than the company's cost of debt, which is unreasonable because equity is always riskier than debt and requires a higher cost of capital, since debt holders are paid before equity holders (7 T 920).

points from 2011 to 2013. Under a conservative adjustment of 50 basis points to the risk-free rate, both witnesses' ROE estimates from the CAPM would increase by 50 basis points (7 T 960).

Staff responds that it used a risk-free rate that is 48-85 basis points higher than Dr. Vilbert's risk-free rate, so there is no need for further adjustment (Staff Initial Brief, pp 30-31). Staff's response is unpersuasive because Staff's higher risk-free rate simply reflects a change over time between Dr. Vilbert's and Staff's testimony. Staff still neglected to account for forecasts that interest rates are going to increase in the future, as discussed above.

Dr. Vilbert further explained that empirical research has long shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta. Low-beta stocks tend to have higher risk premiums than predicted by the CAPM, and high-beta stocks tend to have lower risk premiums than predicted. Neither Mr. Coppola nor Mr. Megginson adjusted for this empirical observation. Dr. Vilbert adjusted by using the ECAPM, which uses these empirical findings to produce results that more closely match the results of empirical tests, and that are more appropriate to use. Had Messrs. Coppola and Megginson recognized and adjusted for this underestimation, then their ROE estimates would have been approximately 20 to 50 basis points higher (7 T 926, 961).

Staff responds by suggesting that the Commission took a dim view of the ECAPM in MichCon's last rate case, Case No. U-15985 (Staff Initial Brief, p 31). Staff's suggestion is unsupported by any citation to anything issued by the Commission in Case No. U-15985, and inconsistent with the Commission's finding that MichCon's ROE should be maintained at 11.0% based on economic conditions, without comment on the underlying analyses used to support that ROE (June 3, 2010 Opinion and Order in Case No. U-15985, p 35)

2. DCF Estimates.

Edison previously explained Dr. Vilbert's application of the DCF model (Edison Initial Brief, pp 30-31). Mr. Megginson's DCF analysis is derived from a sample of companies including FirstEnergy and Allegheny, which recently merged as indicated above. The DCF ROE for Allegheny is approximately equal to the current yield on its debt, which is not economically justified on a forecast basis. FirstEnergy's cost of equity is about 130 basis points less than the sample average. Deleting these two companies from Staff's sample (which Staff acknowledges would be appropriate. Staff Initial Brief, p 27) would increase Staff's sample average estimate by 49 basis points. Staff's DCF estimate is also understated due to an inappropriately low growth rate (7 T 962).

3. Edison's Higher Risk Justifies a Higher Return on Equity.

A rational investor will not make or maintain an investment unless it provides a return corresponding to its risk. The higher the risk, the higher the required return (7 T 894-903). In Edison's last rate case, the Commission properly recognized that "*economic conditions in Detroit Edison's service territory remain uncertain . . . [and] the company's risk environment will continue to be challenging* . . . ." (January 11, 2010 Opinion and Order in Case No. U-15768, pp 20-21). Given current economic conditions and those expected for the foreseeable future, it would be a mistake to reduce Edison's allowed ROE (7 T 910-12)[23].

Messrs. Coppola and Megginson suggest that whatever affects the credit crisis may have had on the cost of capital; the effect is now gone or so small that it can be ignored. To the

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[23] Edison still faces a very difficult business environment because Michigan has been affected to a much greater degree by the financial turmoil than most states, and Edison's service territory is primarily in Southeastern Michigan, which has been deeply affected by the financial crisis. Moreover, two of Edison's largest customers are General Motors and Chrysler, which are both undergoing periods of significant uncertainty. Edison also has an ongoing exposure to Electric Choice (which is partially mitigated by the CIM) (7 T 910, 917-18, 935). Without the CIM, Edison's risk increases and Dr. Vilbert's ROE recommendation would increase by at least 25 basis points from 11.0% to 11.25% (11.375% with 0.125% flotation costs) (7 T 936).

contrary, Dr. Vilbert testified that the cost of capital remains higher today than it was before the credit crisis. There is also still significant uncertainty and volatility in the capital markets. Macroeconomic factors such as unemployment and mortgage foreclosures are very high by historic standards. Investors have changed their asset allocation plans, and are allocating much more of their portfolios to lower-risk investments. In sum, it is overly optimistic to suggest that economic conditions are back to normal, particularly for utilities like Edison that operate in Michigan (7 T 947-52).

Staff responds by asserting that it properly considered economic conditions because "Staff's ROE analysis takes its proxy group's credit rating into account" (Staff Initial Brief, p 27). Staff's response misses the mark because a credit rating does not measure the state of the economy or whether capital markets are more or less risky than they were in some other period. A credit rating is a measure of the default risk on a company's debt. Default risk measures the company's total risk, and not its systemic or non-diversifiable risk, which is the risk that is relevant to shareholders (7 T 957-58). As Dr. Vilbert simply put it: "Just because a company has low credit risk (i.e., a high credit rating) does not mean that the company's ROE risk is also low" (7 T 958).

Staff suggests that a Revenue Decoupling Mechanism ("RDM") and other tracking mechanisms may have an effect on Edison's risk profile, and should be considered by the Commission in setting Edison's ROE, but Staff does not recommend any adjustment to Edison's ROE (Staff Initial Brief, pp 24-25). Wal-Mart similarly suggests that if the Commission continues Edison's current RDM, then the Commission should consider an adjustment to Edison's ROE, but Wal-Mart did not suggest any specific adjustment (Wal-Mart Initial Brief, pp 8-10). ABATE suggests, without any citation or analysis, that the Commission has approved trackers and an RDM that have reduced Edison's business risk and should result in a lower ROE

(ABATE Initial Brief, p 6). These suggestions lack merit, and are either completely unsupported (in the case of ABATE), or consist of vague, generalized references to Staff's assertions in Case No. U-16191, and decisions by other state commissions, none of which is in this record.[24] Staff and Wal-Mart also do not, and tacitly concede that they cannot, draw any connection between their referenced materials and Edison. Staff and Wal-Mart also do not articulate, let alone try to support, any specific ROE adjustment. ABATE arbitrarily suggests a ROE at the midpoint of Staff's range, also without support. Moreover, Staff notes five reasons that each "serves to reduce the net incremental benefit of the approved RDM and other trackers," and therefore weighs against any ROE adjustment (Staff Initial Brief, p 25). Most importantly, the record conclusively demonstrates that no ROE adjustment is justified. Dr. Vilbert explained that the storm expense tracker should have no effect on Edison's ROE, and the UETM (which Edison has requested to be removed) should have a small effect. The RDM should not affect the ROE. A recent empirical study by Dr. Vilbert and other experts analyzed the effect of decoupling on the cost of capital for gas utilities from 2005 through 2010, and found no evidence that decoupling lowered the cost of capital (7 T 936-37, 963).

4. Summary and Recommendations Regarding Edison's Cost of Equity.

Dr. Vilbert explained that his ECAPM numbers deserve more weight than his CAPM numbers because the ECAPM adjusts for empirical findings.[25] The results of using MRPs of

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[24] Again, reliance on materials outside of the record this case is misplaced. Const 1963, Art 6, § 28 requires the Commission's findings to "be supported by competent, material and substantial evidence on the whole record." The Administrative Procedures Act ("APA") precludes the Commission from making decisions based on non-record materials. MCL 24.276 provides: "Evidence in a contested case . . . shall be offered and made part of the record. Other factual information or evidence shall not be considered in determination of the case except as permitted under [MCL 24.277 concerning official notice of judicially cognizable facts and facts within the agency's specialized expertise]." Noncompliance with the APA is reversible error. *In re Public Service Commission Guidelines for Transactions Between Affiliates*, 252 Mich App 254, 267; 652 NW2d 1 (2002).

[25] Dr. Vilbert's CAPM analyses produced estimated ROEs of 9.6% to 10.4% using Value Line's betas, and 10.2% to 11.1% using Bloomberg's betas. His ECAPM analyses produced estimated ROEs of 9.8% to 10.9% using Value Line's betas, and 10.3% to 11.5% using Bloomberg's betas (7 T 928-29).

7.0%, 7.5%, and 8.0% also deserve more weight than the results of using a 6.5% MRP, which does not adjust for the current turmoil in the financial markets. The best point estimate of ROE for the sample is 10.75%; however, Edison has higher risk than the sample, so the corresponding ROE estimate for Edison is 11% (before flotation costs). The single-stage DCF's 11.5% estimate provides additional confidence in this ROE estimate (7 T 888, 915, 930, 934).

Dr. Vilbert also explained that his ROE recommendation is further supported by the lack of improvement in economic conditions since the Commission continued Edison's 11.0% ROE in January of 2010. A supportive regulatory environment coupled with an appropriate allowed ROE are important components to ensure an investment grade credit rating. Maintaining a solid credit rating and outlook are important aspects in maintaining Edison's access to capital, which is particularly important in the present uncertain and volatile economy. Flotation costs are also legitimate expenses that need to be recovered. Therefore, a just and reasonable return on equity for Edison is 11.125%, assuming that the Commission maintains Edison's CIM,[26] and 49% equity ratio (7 T 886, 896, 912, 935, and 937).[27]

Staff's and AG's analyses have a number of flaws, resulting in understated recommendations that should be corrected as discussed in Edison's Initial Brief and above, or simply rejected in favor of Dr. Vilbert's complete and correct expert analysis.

D. Overall Rate of Return.

The sum of the weighted cost of the above-described capital components results in a weighted, after-tax 6.865% overall rate of return (6 T 350; Exhibit A-11, Schedule D1, column (g), line 19). A 1.6355 revenue conversion factor is appropriate for the projected period (6 T 349; Exhibit A-10, Schedule C2). The corresponding weighted pre-tax overall rate of return is

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[26] Without the CIM, Edison's risk increases and Dr. Vilbert's ROE recommendation would increase by at least 25 basis points from 11.0% to 11.25% (11.375% with 0.125% flotation costs) (7 T 936).

[27] If Edison has less equity (and a corresponding increase in both debt leverage as well as risk), then Edison's ROE must increase to compensate for the increased risk (7 T 886, 889, 918).

9.760% (6 T 350; Exhibit A-11, Schedule D1, column (i), line 19). Edison supports the use of the 6.865% overall rate of return in the derivation of its revenue requirements and the use of the 9.760% pre-tax overall rate for the return on all amortization and regulatory asset balances as shown on Reply Brief Attachment A, page 4, line 18, column (i) and (k), respectively.

As discussed in Edison's Initial Brief and above, the Company and Staff are in general agreement with respect to capital structure and overall rate of return, and the Company's positions should be adopted with regard to long-term debt, short-term debt, regulatory liabilities, and ROE.

VI. ADJUSTED NET OPERATING INCOME AND REVENUE DEFICIENCY.

Edison previously explained (Edison Initial Brief, p 36) that its Total Electric adjusted Net Operating Income ("NOI") is projected to deteriorate from $631 million (for the historic 12 months ended December 31, 2009) to approximately $425.0 million (for the projected twelve months ending March 31, 2012) (6 T 342; 7 T 1108-1109; Exhibit A-8, Schedule A1, line 4; Exhibit A-10, Schedule C1, lines 21 and 23) due to increases in depreciation related to capital additions, O&M inflationary increases, operating costs to comply with environmental standards, increases in benefit costs, declining service area sales, loss of bundled sales through Electric Choice migration and loss of existing wholesale for resale contracts, partially offset by Edison's cost reduction programs, and the rates approved by the Commission in Case No. U-15768 (7 T 1107-1108).

Staff recommends a NOI of $550,980,000, stating:

> "Detroit Edison and Staff recommend the same electric sales revenue amount [$4,145,471,000] and miscellaneous revenue amount [$144,435,000]. Staff's sales for resale revenue [$42,938,000] is $33,807,000 higher than the Company's due to the signing of a new wholesale contract with the City of Detroit Public Lighting Department, which occurred after the Company filed its direct testimony. Additionally, Staff recommends an increase to revenue [of $5,857,000] to account for the discount

> received by customers taking service under Large Customer Contracts. This adjustment is necessary to prevent tariff customers from subsidizing customers taking service under special contracts" (Staff Initial Brief, p 32).

Edison acknowledges the contract with the Detroit Public Lighting Department (See Edison's Initial Brief, Attachment A). Other adjustments to Staff's NOI are necessary as further discussed below, and as shown on Reply Brief Attachment A, page 2.

A. Sales Forecast.

Edison previously explained that its revenue deficiency results in part from decreases and continuing weakness in sales (Edison Initial Brief, pp 36-38). Staff states that it "reviewed the Company's forecasted sales and found them to be reasonable" (Staff Initial Brief, p 58). No party appears to disagree.[28]

B. Edison's Construction, Operating and Maintenance ("O&M"), Administrative and General ("A&G") and Infrastructure Costs Are Reasonable and Necessary to Maintain Reliable Electric Service.

1. Steam, Hydraulic and Other Power Generation Capital Expenditures, O&M Expenses and Fuel Handling Expense.

a. Steam, Hydraulic and Other Power Generation Capital Expenditures ("Fossil Generation Plant").

Edison previously explained and supported its Fossil Generation Plant capital expenditures (Edison Initial Brief, pp 38-46). Staff agrees (Staff Initial Brief, p 9).

The AG suggests that his witness, Mr. Coppola, "identified more reasonable capital expenditures that the Commission should adopt . . ." (AG Initial Brief, p 26). The AG's Initial Brief does not include a specific discussion. For brevity, Edison incorporates its prior discussion explaining Mr. Coppola's lack of qualifications to support an opinion regarding fossil generation

[28] AG witness Mr. Coppola erroneously reflected AG witness Mr. Hutts' proposed $28.3 million revenue adjustment for 2009 weather normalization. Ms. Siefman developed a stand-alone, independent sales forecast for the projected test year, irrespective of 2009 actual and/or weather-normalized sales (7 T 1146-47; 8 T 1221-22). On review of Edison's rebuttal testimony, the AG agrees with Edison (AG Initial Brief, pp 15, 31).

capital expenditures, and the lack of merit in his proposed reductions in capital expenditures (Edison Initial Brief, pp 40-43).

MEC/NRDC suggest that Edison's "Marginal Units" (which MEC/NRDC identifies as Edison's Harbor Beach, St. Clair 1-4, Trenton 7 & 8, and Greenwood plants) should be put into cold standby because these plants allegedly are unnecessary in light of forecasted declining sales to Edison's customers (MEC/NRDC Initial Brief, pp 1-14). MEC/NRDC's simplistic suggestion lacks merit and reflects a fundamental misunderstanding of the functioning of the MISO market, and that Edison cannot unilaterally put its plants into cold standby, as explained in Edison's Initial Brief and further discussed below. Staff agrees with Edison and properly concludes that "[a]t this time, these are too many variables to determine which plants should be removed from service." (Staff Initial Brief, pp 10-11) MEC/NRDC's suggestion is also inconsistent with Edison's MISO experience. The MISO Tariff requires that any Market Participant planning to decommission, place into extended reserve shutdown, or disconnect any Generation Resource must notify the Transmission Provider. MISO will then perform analyses to evaluate whether the Generation Resource is required for reliability. Edison followed this process in 2009 to request an extended shutdown of the Conners Creek Power Plant ("Conners Creek"). (6 T 589-90).

MEC/NRDC's proposal is based in part on its witness Mr. Sansoucy's criticism of Greenwood as inefficient from a heat rate standpoint (11 T 1968). That criticism is unsound because Greenwood's operating heat rate is higher than its design heat rate due to the manner in which it is utilized in the MISO market. While the design heat rate is typical of steady state operation at full load, Greenwood does not operate in this manner. Rather, it is operated as a cycling unit which has frequent startups and shutdowns, and extended operation at reduced loads. MISO determines this mode of operation, and it is MISO which economically dispatches generating assets to serve load while meeting system security constraints. Greenwood's

operational flexibility, 785 MW of capacity and its ability to provide high levels of spinning reserve, make it valuable to MISO grid reliability and Edison's customers. By co-optimizing system reliability with overall customer cost the MISO dispatch model minimizes overall customer cost while ensuring reliable power supply to Edison's customers (6 T 481-82, 495, 498, 588).

Mr. Sansoucy's criticism of Harbor Beach similarly does not recognize that Harbor Beach was built in the Michigan Thumb area to provide load security through a stable electric system in that area. Harbor Beach is also operated as a cycling plant by MISO, and its frequent startups and shutdowns cause it to have a somewhat elevated operating heat rate, for much the same reasons as Greenwood. Additionally, Harbor Beach is called upon to generate during periods of maintenance on the transmission system in the Thumb region. If Harbor Beach were removed from service, then new generation capacity or new transmission circuits would need to be installed in its geographic area (6 T 482, 501-502, 505-506, 588-89).

Mr. Sansoucy also discussed the heat rates of St. Clair 1-4 and Trenton 7 & 8, but the more significant consideration is the incremental unit dispatch costs. St. Clair 1-4 and Trenton 7 & 8 are dispatched by MISO to reliably and economically serve load. Although St. Clair 1-4 have somewhat elevated heat rates, heat rate alone does not determine the economics of a unit in the MISO market. These units burn a relatively low cost fuel, and it is the combined impacts of heat rate and fuel cost that determines their overall dispatch cost. MISO makes its dispatch decisions based upon overall dispatch cost. In addition, St. Clair 1-4 and Trenton 7 & 8 provide multiple products in the MISO market including energy, capacity, spinning reserve, and VARs. They are important system assets that continue to be operated to support reliable and economic electric service to MISO, and ultimately Edison's customers (6 T 483). Mr. Sansoucy's cost allocation based only on heat rate for St. Clair 1-4 and Trenton 7 & 8 (Exhibit MEC-4) is also

inaccurate because multiple common costs (e.g., environmental monitoring, plant management, and O&M) are not directly proportional to heat rate and/or coal consumption at a plant (6 T 483-84, 512).

Mr. Sansoucy indicated that the cost difference between running and not running Greenwood, Harbor Beach, St. Clair 1-4, and Trenton 7 & 8 is approximately $65 million in the projected test year, and approximately $750 million through 2020 (11 T 1974-75. See also, MEC/NRDC Initial Brief, pp 4, 7). These calculations are significantly flawed because their main component is fuel expenses. Mr. Sansoucy also neglects to recognize that the plants are economically dispatched by MISO, and receive revenue for both the generation they provide, and for ancillary services. Also, if the plants are not available to generate, then the value of the lost generation, capacity and ancillary services must be replaced with purchases in the wholesale market.[29] Most fundamentally, however, the possibility of saving anything is premised on the unsupported assumption that MISO would approve the removal of these generating units from active service without expensive and time consuming mitigating actions (6 T 590-91, 518-19, 533-34, 537, 539; 7 T 629).

Mr. Sansoucy's apparent lack of understanding of the MISO market is further indicated by his claims that Edison plans to ramp up its least efficient coal units in order to sell electricity from its more efficient plants, and leave less efficient plants to serve Edison's customers (11 T 1976. See also, MEC/NRDC Initial Brief, pp 8-10). As a MISO market participant, Edison is required to offer **all** of its available generation into the market. Edison's generating units follow MISO's dispatch instructions, and are paid market clearing prices for their generation. Similarly,

[29] MEC/NRDC attempt to cast doubt on this point by asserting that Edison did not provide an analysis suggesting that it would be more expensive to purchase any needed replacement power than it would be to operate the Marginal Units (MEC/NRDC Initial Brief, p 7). MEC/NRDC neglect to recognize that MISO makes its dispatch decisions based on overall dispatch cost, as discussed above. Thus, removing an otherwise-dispatched generation unit from MISO availability would plainly indicate MISO's need to utilize a higher cost alternative.

Edison bids its load into MISO, and purchases all of its power from the MISO wholesale market. The net effect is that the design of the MISO market allows Edison customers to be served with the least expensive power available within system reliability constraints. Moreover, any revenue received from Edison's non-requirement sales into the MISO market is a credit to Edison's PSCR customers, who thereby are directly benefited from these sales (6 T 591-92; 7 T 625-27, 649-51).

MEC/NRDC acknowledge that "DTE is likely correct that some transmission grid updates will be needed in order to permanently retire the Marginal Units," but assert: It would not be just, reasonable, or prudent to authorize inclusion in the rate base of plant investments justified by grid reliability concerns, when DTE acknowledges that it has requested and will very soon receive answers about the compensatory measures necessary to meet those grid stability concerns" (MEC/NRDC Initial Brief, p 13).

MEC/NRDC's assertion is factually inaccurate and legally flawed. The record reflects that MISO indicated that it would provide some results in May for Conners Creek and Harbor Beach, but needed a few months to study the other plants (6 T 609-10). Thus, the timing of MISO's results remains speculative. The Commission must complete this case within 12 months after it was filed. MCL 460.6a(3). The parties agreed to a schedule that will allow the Commission to do so. The record is closed, and fully supports Edison's capital expenditures. MEC/NRDC's speculation about what MISO might indicate in the future is not a sound basis for any action by the Commission.[30]

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[30] In *Kar v Hogan*, 399 Mich 529, 539; 251 NW2d 77 (1976), our Supreme Court explained:

> "The party alleging a fact to be true should suffer the consequences of a failure to prove the truth of that allegation."

Thus, unproven allegations cannot stand in the place of evidence. Things not proven must be taken as not existing, since a decision cannot be based upon conjecture. *Star Steel v USF&G*, 186 Mich App 475, 481; 465 NW2d 17 (1990); *see also, Skinner v Square D Co*, 445 Mich 153; 516 NW2d 475 (1994).

Moreover, MEC/NRDC implicitly assume, with absolutely no basis, that transmission upgrades necessary for the retirement of the "Marginal Units" would be simple, uncontested, and without costs to Edison's ratepayers. MEC/NRDC neglect to recognize that Edison relies on ITC to transmit electricity to its distribution system in Southeast Michigan. Thus, when obtaining transmission services to and throughout its service territory, Edison does and will pay for those transmission services based on the FERC-approved rates for ITC and MISO transmission services. Those ITC and MISO transmission costs are passed on to Edison's customers, who have to pay them. Those costs may be substantial, leading to contested proceedings in which proposed transmission upgrades may be disallowed. For example, in Case No. U-14933, ITC applied for a certificate of public convenience and necessity to build a $150 million transmission line under the Electric Line Certificate Act, 1995 PA 30, MCL 460.561 *et seq* ("Act 30"). Edison intervened in the proceedings to protect the interests of its customers, who would have to pay for most of the cost of ITC's proposed line (approximately $24 million per year). The Commission denied ITC's application, properly recognizing that if ITC built its proposed transmission line, then Michigan ratepayers would have to pay for it:

> "Payments made by Detroit Edison and Consumers for transmission costs under **FERC-approved rates are recoverable from ratepayers** (as transportation costs) through the power supply cost recovery mechanism. MCL 460.6j(1)(a); *Detroit Edison Co v Public Service Comm*, 276 Mich App 216; 740 NW2d 685 (2007). **Thus, a direct consequence of the construction of a new transmission line is that the costs of that construction will ultimately be borne by this state's ratepayers**. MCL 460.6j(5), (12). *See, also*, MCL 460.572. In this case, **the Commission is**

It is similarly well established that an agency decision may not be based on speculation. *Ludington Service Corp v Comm'r of Insurance*, 444 Mich 481, 483, 494-97, 500-501, 507; 511 NW2d 661 (1994), *amended* 444 Mich 1240 (1994) (unanimously reversing agency decision that exceeded the limits of the agency's statutory authority, and that was based on speculation instead of the required competent, material and substantial evidence); *In re Complaint of Pelland*, 254 Mich App 675, 685-86; 658 NW2d 849 (2003); *Battiste v Dep't of Social Services*, 154 Mich App 486, 492; 398 NW2d 447 (1986) (holding that agency's decision was not supported by evidence that a reasonable person would consider adequate).

> **required to weigh whether, in the current economic climate, increased annual charges of approximately $24 million for Detroit Edison ratepayers, and $2 million for Consumers ratepayers, are justified, which requires a thorough examination of evidence supporting the necessity for the line**. (February 22, 2008 Opinion and Order in case No. U-14933, p 14. Emphasis added).[31]

Staff "strongly recommends that the Commission put Detroit Edison on notice that should a 'marginal' plant be taken out of service with a positive plant balance; Detroit Edison will have to provide full support for decisions leading to the expenditures, and the removal of the plant from service. (11 T 2297). In the alternative, should their support prove insufficient, recovery will be pro-rated . . ." (Staff Initial brief, p 9). Staff goes on to outline why MEC/NRDC's cost assessment is incorrect (quoting Edison witness Mr. Fessler at 6 T 484), and recognize that MEC/NRDC's approach is "fatally flawed" (Staff Initial Brief, pp 10-11). Edison agrees that MEC/NRDC's position lacks merit, but remains concerned that Staff, without a defined process or a defined standard, is suggesting a new regulatory standard for generation units that Staff considers "marginal." Staff's suggestion that a zero balance should be achieved before a plant is retired indicates that 40 years (the average depreciation life of plants) may need to elapse between the last capital investment and the retirement. This is not a workable option in light of safety, environmental, legal, reliability, and other standards to which Edison must adhere (6 T 484-85).

b. Fossil Generation O&M Expense.

Edison previously explained and supported its Fossil Generation O&M expenses (Edison Initial Brief, pp 46-48).

The AG supports its witness Mr. Coppola's suggestion to eliminate $11.4 million for "general inflation" (all of the Fossil generation O&M labor and material cost adjustments from

[31] ITC appealed in Court of Appeals No. 284348, but stipulated to dismiss that appeal as oral argument approached.

January 1, 2010 through March 31, 2012, as shown on Exhibit A-10, Schedules C5.1, C5.3, and C5.4), based on the flawed and unsupported proposition that Edison could somehow simply freeze its labor costs, and avoid escalating material costs (AG Initial Brief, p 33; 10 T 1763, 1768). Mr. Coppola's suggestion should be rejected. Mr. Coppola's proposal is not supported by any data from any other electric utility, and Mr. Coppola does not dispute the labor and material adjustment factors utilized by the Company, and the measures used to mitigate those increases (6 T 451-67, 472). More importantly, Mr. Coppola's suggestion to use only historical costs is unreasonable because labor and materials make up 70% of Fossil Generation's O&M expenses. Roughly 60% of the Steam Power Generation internal labor force is union represented, and will receive contractual 3% wage increases in 2010, 2011, and 2012. Edison is also exposed to other cost increases that are largely beyond its control, such as outside contractor union labor wage rates, and commodity prices including the cost of fuel for power plant heavy equipment (6 T 472-73, 550. *See also*, January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, p 38, recognizing commodity cost increases and labor cost increases due to union negotiated contracts). Under cross-examination Mr. Fessler stated that although Edison seeks bids from alternative suppliers, outside contractors such as "millwrights, boiler makers, iron workers, carpenters, electricians have gotten pay raises" (6 T 549-550).

Mr. Coppola's suggestion to remove $3.0 million for environmental monitoring equipment similarly should be rejected (AG Initial Brief, p 33; 10 T 1767). Mr. Coppola simply assumed, without data or analysis, that at least half of Edison's projected expenses for environmental monitoring would not be incurred. The record demonstrates, however, that as of April 2011, there are 46 full-time Edison employees working on the Monroe Power Plant's Flue Gas Desulfurization ("FGD") systems, all of whom are doing work that was not required before the new environmental control equipment was installed (6 T 473-74). In addition, the

incremental expenses also relate to environmental monitoring and air permit implementation and compliance (6 T 460).

Mr. Coppola's suggestion to remove $9.9 million related to major outages expense is similarly unjustified (AG Initial Brief, p 33; 10 T 1768). He misinterpreted a discovery response that clearly provided data only for outages with a duration of 5 weeks or greater (Exhibit A-28, Schedule PF-1) and misapplied it to Edison's $42 million forecast for all planned outages regardless of duration. Edison's $42 million forecast is further supported by historical expenditures for the last 5 years (6 T 474-75; Exhibit A-28, Schedule PF-2).

2. Fermi 2 Capital Expenditures and O&M Expenses.

a. Fermi 2 Capital Expenditures.

Edison and Staff agree on the appropriate level of capital expenditures for the Fermi 2 Nuclear Power Plant ("Fermi" or "Fermi 2"), which Edison previously explained and supported as reasonable (Edison Initial Brief, pp 48-50; Staff Initial Brief, p 9).

The AG, without discussion, supports its witness Mr. Coppola's suggestion that security system expenditures should be reduced by $4.8 million (AG Initial brief, p 26; 10 T 1812). The suggestion should not be adopted because reduced spending in 2010 and 2011 was due to project timing, not performance. The $4.8 million is still a reasonable and prudent expenditure that is needed through the projected test year to complete the security system projects (9 T 1610; Exhibit A-9, Schedule B6.2, lines 7 and 10). In addition, this project is a multiyear, very significant, complicated project, and multiyear projects of that magnitude can be expected to have timing issues (9 T 1658).

b. Fermi 2 O&M Expenses.

Edison previously explained that $154.3 million of O&M will be required to support the safe and reliable operation of Fermi in the projected period ending March 2012, which is prudent

and reasonable (Edison Initial Brief, pp 50-53; 9 T 1591; Exhibit A-10, Schedule C5.2, line 22, column (l)).

AG witness Mr. Coppola suggested that Fermi 2 O&M expenses for the projected test year should be at the 2009 level of $143.2 million, based on the simplistic proposition that Edison could simply hold the line on cost increases and negotiate cost decreases in the local economic environment (10 T 1770). Mr. Colonnello responded that the suggestion should be rejected because Fermi 2's operating expenses are more influenced by the national commercial nuclear market and regulatory forces than by the local economic environment. For example, a Nuclear Regulatory Commission ("NRC") notification states that hourly inspection fees will increase 5.4% in 2011, and Institute of Nuclear Power Operations ("INPO") dues increased 4.7% in 2011. Commercial nuclear vendors are international companies operating in a niche market where supply is limited and demand is high. Fermi 2 projects refueling service costs to increase by at least $1 million per refuel outage, which represents an annual inflation rate of 15%. Approximately 35% of Fermi 2's workforce is represented by unions, and will contractually receive at least 3% annual salary increases. Fermi 2 must also pay nationally competitive wages to its non-represented professionals in order to attract and retain specialty-skilled, highly-trained personnel (9 T 1607-1608, 1632-34, 1642-43, and 1647-48). Under cross-examination, Mr. Colonnello supported Fermi's justification for paying nationally competitive wages:

> "Nuclear business is a very small niche market. If you know, and I'll tell you, there's 64 nuclear stations or sites within the United States, and let's just round that down to approximately 60 for easy math purposes. At every one of those stations there might be approximately 500 non-represented personnel. So you have about a market of 30,000 people within the United States to recruit for your nuclear operations. As with many businesses at this point in time, the age of the workforce is approaching retirement. We are focused on providing safe services at the nuclear station, which means we want the most experienced personnel that we can get in the country, and at times we recruit externally to get those personnel, that helps us ensure that we do not become insular and

> we always have fresh eyes coming in to the organization to understand nuclear, nuclear safety and nuclear standards. It's a very specialty skilled, high-trained personnel that, for which we have a very small market to recruit from. So I do believe the 3-percent escalation is warranted. It's a market that we're competing with, it's not a local market we're essentially completing [sic competing] with, we're competing on a national basis, and on a national basis, it's reasonable and prudent to retain the personnel that we have at the station" (9 T 1647-48)

There is similarly no merit in the AG's assertion that: "Most of the inflation rate consists of wage increases and other expenses not directly related to the critical operations of the nuclear facility" (AG Initial Brief, p 34). The record demonstrates that it is reasonable to expect cost increases in the specialized nuclear market, and it is unrealistic for the AG to suggest that Edison could attract and retain personnel with the requisite skills to operate a nuclear power plant without paying competitive wages.

Moreover, Mr. Coppola acknowledged on cross examination that he has never worked at an operating nuclear facility, or hired employees to work at a nuclear facility (10 T 1906-1907), he is not familiar with NRC inspections, inspection fees, or regulations regarding the security of nuclear plants (10 T 1907), and he has never been personally involved in purchasing uranium or other nuclear fuel services (10 T 1907-1908). Mr. Coppola simply has no reasonable basis to estimate nuclear expenses.

Mr. Colonnello further explained that Fermi 2's overall 3.5% inflation rate is reasonable, since Fermi 2 has managed its O&M expenses to within $1 million of benchmark plants. The O&M inflation at benchmark plants has increased at substantially more than 3.5% annually, and it is reasonable to expect this trend to continue. Driving Fermi 2 costs below benchmark levels, as Mr. Coppola suggests, is neither reasonable nor sustainable (9 T 1609-10) Under cross-examination Mr. Colonnello reiterated that Edison's 3.5% inflation rate is reasonable compared to benchmark plants:

> "We did look at other single-asset owners, and we were within the benchmark of those single-asset owners, which tells us that we have reasonable and prudent expenses associated with operating the facility. And when I looked at the escalation associated with those benchmark plants, I['ve] seen the benchmark plants inflating at a rate of roughly 5 percent a year" (9 T 1656).

Mr. Coppola suggested that an increase of $4.1 million for nuclear fuel cost should be disallowed, allegedly because Edison did not justify it (10 T 1813).[32] Mr. Colonnello responded that it is reasonable and prudent for Edison to abide by the confidentiality of the nuclear fuel proprietary pricing agreements, which are common in the industry. Fermi 2's nuclear fuel cost consistently approached top quartile performance as compared to its peers from 2005 through 2010. This strong record demonstrates a commitment to cost control. Edison has reasonably and prudently managed its nuclear fuel cost in the past, and will continue to do so in the future (9 T 1610-11).

MCAAA witness Mr. Peloquin suggested that Nuclear Energy Institute ("NEI") dues should be disallowed, contending that the NEI is primarily a lobby group (11 T 2070). To the contrary, the vast majority of NEI's activities do not involve lobbying. Fermi 2 benefits from NEI when a coordinated response to proposed regulations and policies is necessary. For example, NEI has coordinated the nuclear industry's legal actions with respect to the federal government's spent nuclear fuel ("SNF") acceptance responsibility, as further discussed below. Therefore, NEI dues are prudent and beneficial to Edison's customers, and should be allowed for recovery (9 T 1612-13, 1721).

c. Fermi 2 Spent Nuclear Fuel ("SNF") Expenses.

Edison previously explained that Fermi's spent nuclear fuel ("SNF") expenses are prudent and reasonable, and that MCAAA simply rehashes arguments that the Commission has

[32] Of course, in any event, and as explained above, Mr. Coppola does not possess the requisite knowledge or experience to properly evaluate nuclear costs.

repeatedly rejected (Edison Initial Brief, pp 53-59). MCAAA's propensity for duplication is further reflected in briefing that consists largely of reprinting its witnesses' testimony (MCAAA Initial Brief, pp 1-22).

MCAAA witness Mr. Peloquin suggested that costs and expenses resulting from the DOE's partial breach of its SNF contract with Edison should be collected from the DOE, and not Edison's customers (11 T 2065-66). The suggestion should be rejected because Edison has acted responsibly and reasonably in its handling of the DOE's delay in accepting SNF. The DOE has continued to acknowledge its obligation to accept SNF from Edison and other nuclear utilities. Edison and other nuclear utilities continue to pursue damages against the DOE. In the meantime, Edison requires additional onsite spent fuel storage in order to continue the reasonable and prudent operation of Fermi 2 for the benefit of its customers. There is no legitimate reason why Edison should be penalized by MCAAA's proposals, or be denied recovery of the capital and O&M expenses necessary to operate Fermi 2 (9 T 1613-14, 1678-80, 1682, 1698, 1701-1702, 1707-1709, 1725).[33]

There is similarly no merit in MCAAA witness Mr. Callen's allegations that Edison has not been reasonable and prudent in incurring SNF costs (11 T 2024). As discussed in Edison's Initial Brief and above, Edison has been very effective in managing its nuclear fuel expenses. Fermi 2's fuel expenses include fees that Fermi 2 pays to the DOE for SNF disposal (9 T 1614).

Edison has taken a conservative and graduated approach to manage on-site spent fuel storage, with incremental investments based on the best available information regarding when the DOE would begin accepting SNF. This graduated approach to on-site storage was, and is, in the best interest of Edison's customers. Similarly, O&M expenses of moving fuel from wet to dry storage are a necessary expense of continuing to operate Fermi 2 to provide economic

[33] Mr. Peloquin's attempted analogy to Consumers Energy Company ("Consumers") lacks relevance because, among other things, Consumers has divested its nuclear generating assets (9 T 1618-19).

generation to Edison's customers. Edison also continues to pursue damages against the DOE, and Edison is engaged in political initiatives. Edison's actions are appropriately responsive, very reasonable, and in line with the actions of other U.S. nuclear utilities. SNF storage is a national issue, and Edison has responded reasonably and prudently, and in a manner that is consistent with the responses of its peers in the commercial nuclear industry. Messrs. Callen and Peloquin have failed to offer any legitimate criticism of Edison's management of Fermi 2 and SNF (9 T 1614-20, 1673, 1701-1702, 1707-1709, 1725). Under cross-examination, Mr. Colonnello further supported Detroit Edison's actions related to spent fuel:

> "The basis for my statements in my rebuttal in that regard are centered around the actions that we have taken to date to ensure that all our actions have been prudent and reasonable around spent fuel management. I believe Detroit Edison, in our actions, have been indeed prudent and reasonable. We have participated in a number of legal actions, as I mentioned earlier. We have taken a reasonable and conservative approach in how we implemented additional spent fuel storage at the station. That is, we took a graduated approach to ensure that we did not overcommit expenditures on spent fuel storage. We have done just about all, all the actions that I could think that would be reasonable to take, and I don't see our action any different than any other utility or company within the United States regarding spent fuel storage. The basis is that I think our actions have been reasonable and prudent and it would be unreasonable, given that we have taken appropriate actions, to have Detroit Edison accept responsibility solely for paying the spent nuclear fuel fee" (9 T 1701-02).

MCAAA's suggestion that Edison is ignoring the SNF issue is grossly inaccurate (MCAAA Initial Brief, p 9). In addition to Edison's reasonable and prudent actions regarding SNF, as discussed in Edison's Initial Brief and above, Edison has also repeatedly addressed SNF issues before the Commission. MCAAA simply rehashes the same flawed arguments that MEC/PIRGIM repeatedly presented to the Commission through the same counsel and witness. The Commission consistently rejected those arguments, and has consistently been upheld on appeal. The Commission has repeatedly recognized that SNF disposal is a national problem, and

that Michigan utilities must comply with federal law. For example, in Case No. U-12613 (a WPS Corporation PSCR case), MEC/PIRGIM challenged (as MCAAA does here) the utility's recovery of SNF fees paid to the Nuclear Waste Fund, and argued that the Commission should require the utility to make escrow payments equal to the SNF fees. MEC/PIRGIM contended that the escrow would provide a contingent funding source for disposal of SNF in the event that the DOE defaults on its obligation to take utilities' SNF. The Commission rejected MEC/PIRGIM's arguments, explaining.

> "[T]he MEC/PIRGIM's proposals are not necessary to correct any showing of an unreasonable or imprudent action or omission on the part of WPS Corp's management that adversely affects the rates paid by PSCR customers. **The problem is larger than WPS Corp's nuclear operation, feasible alternatives to the DOE's construction of a permanent repository are not readily apparent, and the Commission is unable to find that WPS Corp has been imprudent**" (November 20, 2001 order in Case No. U-12613, pp 8-9 (emphasis added; citation omitted).[34]

The Commission followed this holding in Case No. U-13808 (an Edison rate case), noting that it had repeatedly rejected MEC/PIRGIM's identical arguments in prior cases:

> "MEC/PIRGIM maintains that the ALJ erroneously endorsed the position taken by Detroit Edison regarding the issue of spent nuclear fuel (SNF) fees by finding that the matter should not be considered in this proceeding.
>
> "The Commission finds that the ALJ cannot be faulted for his recommendation. On several prior occasions, the Commission has addressed related issues. See, the November 20, 2001 order in Case No. U-12613" (November 23, 2004 Opinion and Order in Case No. U-13808, p 120).[35]

The Commission's MEC/PIRGIM Rehearing Order further explained:

[34] The Court of Appeals affirmed and our Supreme Court declined to review the Commission's decision. *Michigan Environmental Council v Public Service Comm*, unpublished opinion per curiam of the Court of Appeals, decided December 9, 2003 (Docket Nos. 240403 and 240406), *lv den* 471 Mich 870 (2004).

[35] The ALJ set forth a more detailed discussion in his Proposal for Decision (pp 110-13), outlining the requirements of federal law and recommending that the Commission follow its prior decision in Case No. U-12613.

> "The Commission finds that the petition for rehearing should be denied, as the petition does not meet the standards for granting rehearing. MEC/PIRGIM merely raises again the same arguments that the Commission should involve itself in judging the reasonableness of costs assessed by federal statute. The Commission finds that Detroit Edison has provided sufficient basis upon which to find that it has reasonably and prudently incurred its SNF costs, and MEC/PIRGIM has not successfully demonstrated otherwise.
>
> "As the Commission intended to convey in its November 23, 2004 order, it agrees with the discussion and conclusions of the Proposal for Decision at pages 110-113. The Commission is not persuaded that it should reach a different conclusion at this time" (June 30, 2005 Order in Case No. U-13808 denying MEC/PIRGIM's petition for rehearing, p 6).

The Court of Appeals affirmed. *In re Application of Detroit Edison Co*, 276 Mich App 216; 740 NW2d 685, 701 (2007) ("we reject all of plaintiff's arguments regarding the SNF-related issues and hold that the PSC properly rejected all of MEC/PIRGIM's SNF-related challenges"), leave denied by Michigan Supreme Court as to SNF issues, September 19, 2008 (Docket 134674), certiorari denied by the United States Supreme Court, January 12, 2009 (Docket No. 08-573).

In Edison's next rate case, Case No. U-15244, the Commission found that "MEC/PIRGIM's proposals here differ little from proposals raised and rejected in past proceedings," and recounted its rejection of MEC/PIRGIM's SNF arguments in Case Nos. U-12613, U-12615, and 13917 (December 23, 2008 Opinion and Order in Case No. U-15244, pp 60-61). Although res judicata and collateral estoppel do not apply in the pure sense, there is no requirement nor other sound basis for the Commission to revisit its earlier decisions, which the Courts have upheld. *See also, Pennwalt Corp* v *Public Service Comm*, 166 Mich App 1, 9; 420 NW2d 156 (1988); June 10, 2008 Opinion and Order in Case No. U-15245, pp 36 and 59.[36]

[36] Edison was also involved in key SNF litigation, including *Indiana Michigan Power Co v Dept of Energy*, 88 F3d 1272 (DC Cir 1996) and *Northern States Power Co v Dept of Energy*, 128 F3d 754 (DC Cir 1997). In those cases,

The result is unchanged by recent events, which are inaccurately characterized by MCAAA. For example, MCAAA cites the Nuclear Regulatory Commission's ("NRC") Waste Confidence Decision Update, 75 Fed Reg 81037 *et seq* (December 23, 2010), to suggest that the federal government now contemplates doing nothing "for 100 years or more . . . while the SNF builds up at the DECo plant and then degrades due to inaction" (MCAAA Initial Brief, p 22. *See also, Id* at 6). The NRC update instead found reasonable assurance that "sufficient mined geologic repository capacity will be available to dispose of the commercial high-level radioactive waste and spent fuel generated in any reactor when necessary." (75 Fed Reg 81038. *See also*, 9 T 1678-79) The NRC did not predict when a SNF repository will be available, but instead simply found reasonable assurance, based on national law and policy as well as "decades of scientific studies" supporting a SNF repository, that one would be available before SNF storage becomes unsafe or would result in significant environmental impacts (75 Fed Reg 81041, n 3, 81049. *See also*, 9 T 1726).

The result is also unchanged by the Commission's order that Consumers establish a trust fund for its pre-1983 liability. MCAAA acknowledges: "The issue in Case No. U-16191 was Consumers proposal to pay the DOE its $183 million obligation for **pre-83** spent nuclear fuel disposal" (MCAAA Initial Brief, p 18. Emphasis added). Edison is unlike Consumers, which had nuclear generation assets that operated prior to 1983 and the establishment of the Standard Contract. Edison has only a current liability to pay the DOE a 1 mill per kWh fee. Edison has no

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Edison either directly or through a utility group, cooperated and exchanged information about SNF with members of the Commission and other interested parties. MCAAA's own attorney surely cannot question Edison's efforts in this regard. In his former role as Assistant Attorney General in charge of the Public Service Division, he participated in meetings of the Nuclear Waste Strategy Coalition, and he personally argued the cases of *Indiana Michigan Power Co*, and *Northern States Power Co*, on behalf of a large number of the affected parties. In those cases, the public service commissions of many states and many utility companies joined forces to seek relief from the DOE's progress in dealing with SNF disposal. A review of those decisions reveals that the issues in those cases are in essence the same issues that MCAAA rehashes in this case.

pre-1983 SNF obligations because Fermi 2 went into commercial operation in 1988, so the treatment of Consumers' pre-1983 liability is irrelevant to Edison (9 T 1620-21).

Moreover, the suggestion that Edison should withhold nuclear waste fees paid under the Standard Contract could result in Edison being found in default of its contract with the DOE. Section 302(b) of the Nuclear Waste Policy Act ("NWPA") requires the holders of nuclear power plant operating licenses to enter into the Standard Contract with the DOE. If Edison had not signed the Standard Contract, then the NRC would have been prohibited from granting Edison an operating license for Fermi 2. If Edison were to be found in default on its contract by not paying fees into the nuclear waste fund, but instead placed them in an escrow fund as MCAAA suggests, then Edison would risk the NRC's denial of license amendments necessary to operate the Fermi plant, and could jeopardize Edison's lawsuits for damages against the DOE (9 T 1621-22, 1624, 1704-1705). *See also, Roedler v Dep't of Energy*, 255 F3d 1347, 1350 (CA Fed, 2001) (the utility "has paid and apparently continues to pay the [Nuclear Waste] fee, as a condition of the continuing operation of its nuclear-fueled electricity generating facilities.").

MCAAA's suggestion that there is no issue of federal preemption similarly lacks merit (MCAAA Initial Brief, pp 12-13). Edison has no option, short of violating federal law (and jeopardizing its Fermi 2 license), but to pay the federally-mandated charge.[37] The NWPA represents a "comprehensive scheme" for the disposal of SNF and establishes specific duties and responsibilities for the federal government, the States and the civilian nuclear power industry. *General Electric v Dep't of Energy*, 764 F2d 896, 898 (CA DC, 1985). Under the NWPA, the federal government has express responsibility for the long-term storage and permanent disposal

[37] The NWPA clearly states "For electricity generated by a civilian nuclear power reactor and sold on or after the date 90 days after January 7, 1983, the fee [to offset the costs of disposal of high level radioactive waste and spent nuclear fuel] shall be equal to 1.0 mil per kilowatt-hour." 42 USC § 10222(a)(2). While the Standard Contract is the mechanism for the collection of this fee, it is clear that Congress intended the fee to be paid even in the absence of such a contract. *See*, 42 USC § 10222(a)(3) (stating that the fee was retroactive prior to the initiation of the Standard Contracts).

of SNF and high-level nuclear wastes (42 USC § 10143), the process of siting storage and disposal facilities for nuclear waste (42 USC § 10121-10175), and the establishment of a funding mechanism to pay for these activities, i.e., the Nuclear Waste Fund (42 USC § 10222). There is no authority under the Act for a state regulatory agency to substitute its judgment or require a utility to alter the federally-mandated relationship between the utility, the DOE and the NRC.

Although Edison shares the frustration of many others regarding the DOE's progress in developing a facility for the disposal of SNF, the Commission cannot prevent Edison from receiving full and timely recovery of the mandatory SNF fees and costs from its customers. Both state and federal courts have consistently held that a state utility commission setting retail rates must allow, as reasonable operating expenses, any costs incurred by a utility pursuant to federal mandate. In the leading case, *Narragansett Electric Co v Burke*, 119 RI 559, 381 A2d 1358 (1977), *cert den* 435 US 972 (1978), the Supreme Court of Rhode Island held that the state utility commission could not prevent a utility from recovering amounts it paid under federally-authorized wholesale rates. Recovery of those amounts from the utility's retail customers could not be denied on the ground that those costs, for whatever reason, were "unreasonable." The Michigan Court of Appeals, as well as other state courts that have considered the question, have uniformly agreed that a utility's costs based upon federally-established charges must be treated as reasonably-incurred operating expenses for the purposes of setting appropriate utility rates.[38]

This principle has been recognized by the United States Supreme Court to be a matter of federal supremacy. *Nantahala Power and Light Co v Thornburg*, 476 US 953 963; 90 L Ed 2d 943, 952; 106 S Ct 2349 (1986). In *Nantahala*, the Court held that a state utility commission

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[38] *ABATE v Public Service Comm*, 192 Mich App 19, 22-27; 480 NW2d 585 (1991); *Attorney General v Public Service Comm #2*, 171 Mich App 700, 702; 431 NW2d 49 (1988); *Public Service Comm of Colorado v Public Utilities Comm*, 644 P2d 933 (Colo, 1982); *United Gas Corp v Mississippi Public Service Comm*, 240 Miss 405, 127 So 2d 404 (1961); *General Motors Corp v Illinois Commerce Comm*, 143 III 2d 407, 574 NE2d 650 (1991); *Citizens Gas Users Ass'n v Public Utility Comm*, 165 Ohio State 536, 138 NE2d 383 (1956); Washington Gas Light Co v Public Service Comm, 508 A2d 930 (DC App, 1986); and *Eastern Edison Co v Dep't of Public Utilities*, 388 Mass 292, 446 NE2d 684 (1983).

exercising jurisdiction over retail utility rates may not prevent a utility from passing through to its retail customers the costs the utility has incurred through payment of federally-authorized wholesale rates. The Court explained that "a state utility commission setting retail prices must allow, as reasonable operating expenses, costs incurred as a result of paying a FERC-determined wholesale price. . ." 476 US at 965; 90 L Ed 2d at 955. The Court adopted and applied the *Narragansett* line of cases:

> "[F]or a state ratemaking agency to disregard a FERC-filed rate would clearly be inconsistent with the exclusive federal regulatory scheme over interstate wholesale power prices. The FERC-approved rate at which the middleman purchased power would not be fully recognized as a cost in the retail market, thereby forcing the middleman to sell power at less than its reasonable cost as determined by the federal agency. . . .
>
> ". . . When FERC sets a rate between a seller of power and a wholesaler-as-buyer, a State may not exercise its undoubted jurisdiction over retail sales to prevent the wholesaler-as-seller from recovering the costs of paying the FERC-approved rate. [Citing *Narragansett* line of cases]. Such a 'trapping' of costs is prohibited. Here, *Nantahala* cannot fully recover its costs of purchasing at the FERC-approved rate if the state commission's order is allowed to stand." 476 US at 969- 970; 90 L Ed 2d at 956.

In *Mississippi Power & Light Co v Moore*, 487 US 354; 108 S Ct 2428; 101 L Ed 2d 322 (1988), the United States Supreme Court again applied this principle to bar a state public utility commission's attempt to prohibit a utility's recovery of FERC-mandated payments through local retail utility rates. The Court stated:

> "In this case as in *Nantahala* we hold that 'a state utility commission setting retail prices must allow, as reasonable operating expenses, costs incurred as a result of paying a FERC-determined wholesale price. . . . Once FERC sets such a rate, a State may not conclude in setting retail rates that the FERC-approved wholesale rates are unreasonable. A State must rather give effect to Congress' desire to give FERC plenary authority over interstate wholesale rates, and to ensure that the States do not interfere with this authority.' *Nantahala*, 476 US at 965, 966; 106 S Ct 2349; 90 L Ed 2d 943. Thus we conclude that the Supremacy Clause compelled the MPSC to permit MP&L to recover as a

> reasonable operating expense costs incurred as the result of paying a FERC-determined wholesale rate for a FERC-mandated allocation of power." 487 US at 373; 101 L Ed 2d at 339-340.

This principle of federal preemption, first articulated in *Narragansett* and other state court decisions and later recognized by the United States Supreme Court in *Nantahala* and *Mississippi Power & Light*, precludes the Commission from disallowing Edison's federally-mandated SNF fees and costs. Moreover, the federal rates at issue here were not just set by a federal agency pursuant to Congressional delegation - - **they were set by Congress itself**. In the NWPA, Congress created a comprehensive scheme for the interim storage and ultimate disposal of SNF generated by civilian nuclear power plants. Congress has expressly mandated Edison's payment of SNF fees to the DOE pursuant to 42 USC § 10222. The Commission has no authority to "trap" these federally-required costs. The Supremacy Clause (US Const, art VI, § 2) and the cases cited above require the Commission to allow Edison to recover from its customers all such federally-mandated charges.

The record confirms that there continues to be no merit in the suggestions (previously by MEC/PIRGIM, and now by MCAAA) that Edison could pay the DOE and place an additional amount in an escrow fund, because this would unnecessarily and unjustly increase costs for Edison.[39] Such an action and corresponding cost increase would not be in the best interests of Edison or its customers. SNF is a national issue that the federal government has obligations and

[39] Edison has constitutional protections against "takings" and confiscatory rates under the Fifth Amendment to the US Constitution, which is applicable to the states through the Fourteenth Amendment. Similarly, Mich Const 1963, Art 10, §2 provides in part, "Private property shall not be taken for public use without just compensation therefore being first made or secured in a manner prescribed by law." These constitutional protections have been recognized and applied to public utility rates in well-established case law. See generally, *Missouri ex rel Southwestern Bell Telephone Co v Public Service Comm of Missouri*, 262 US 276; 43 S Ct 544; 67 L Ed 981 (1923); *Federal Power Comm v Natural Gas Pipeline*, 315 US 575; 62 S ct 736; 86 L Ed 1037 (1942); *Duquesne Light Co v Barasch*, 488 US 299; 109 S Ct 609; 102 L Ed 2d 646 (1989) . See also, *Northern Michigan Water Co v Public Service Comm*, 381 Mich 340; 161 NW 2d 584 (1968); *Consumers Power Co v Public Service Comm*, 415 Mich 134; 327 NW2d 875 (1982); *ABATE v Public Service Comm*, 430 Mich 33; 420 NW2d 81 (1988). Any suggestion regarding past SNF fees would also constitute unlawful retroactive ratemaking and an unconstitutional taking. *Michigan Bell Telephone Co. v PSC*, 315 Mich 533 (1946); *Detroit Edison v PSC*, 416 Mich 510, 522-523 (1983).

incentives to resolve, so it is reasonable to expect that the federal government will eventually accept SNF for disposal.[40] Therefore, placing nuclear waste fees in an escrow fund is unreasonable and not necessary to protect customers from default by the federal government (9 T 1622-25, 1678-80, 1682, 1707-1709, 1725).

Mr. Peloquin's suggestion that Edison be required to file a contested case for the distribution of damages that Edison may receive through litigation against the DOE is premature and speculative. It is also unnecessary, since the Commission currently receives annual reports updating the status of Edison's litigation with the DOE in Case No. U-15244 (9 T 1623-24).

d. Nuclear Decommissioning Funding.

Staff agrees that Edison's proposed nuclear decommissioning surcharge reduction is reasonable. (Staff Initial Brief, p 49) ABATE, however, suggests that the assumed cost escalation rate in the nuclear decommissioning fund calculations be reduced from 6.0% to 5.0% (ABATE Initial Brief, pp 5-6). This suggestion should be rejected as imprudent because it could result in a shortfall when Fermi 2 is decommissioned, and thus place a significant burden on customers that could be avoided.[41] MCAAA's suggestion (MCAAA Initial Brief, p 52) to cease funding the decommissioning trust should similarly be rejected as imprudent from a funding perspective, and unsoundly based on a concern that the Fermi 2 balance might temporarily be too high on an actuarial basis.[42]

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[40] MCAAA's own Exhibit No. MCA-7 confirms that the DOE maintains its obligation to take possession and dispose of the nation's spent nuclear fuel.

[41] The nuclear decommissioning trust fund assets are offset by the Fermi 2 decommissioning liability, both of which are included in working capital (7 T 1138; Exhibit A-29, Schedule TMU-2).

[42] As further discussed in Edison Initial Brief section IX, Edison supports a $19.5 million annual reduction in the Fermi 2 decommissioning surcharge (from the current average of $33 million per year to approximately $13.5 million per year), which would coincide with the rate changes resulting from the Commission's final order in this case. Edison's proposal is consistent with its intent to pursue an operating license extension that would allow Fermi 2 to operate an additional 20 years beyond its current operating license, which expires in 2025, thus providing a longer period of time to accumulate funding needed for end-of-life decommissioning (8 T 1362-63; 9 T 1601-1603; Exhibit A-19, Schedule K1 shows the calculation of the annual Fermi 2 end-of-life decommissioning funding

Finally, Edison's January 2012 report should be deferred to April 2015, despite Staff and MCAAA's disagreement (Staff Initial Brief, pp 49-50; MCAAA's Initial Brief, pp 50-53), since a final order in this case addressing Fermi 2 decommissioning funding in late 2011 will render it meaningless for Edison to file another report approximately two months later. The Commission also should not follow MCAAA's suggestion (MCAAA Initial Brief, p 53) to set Edison's January 2012 Decommissioning Trust Fund Report for contested case hearings, since there are too many unknowns in Fermi 2's life cycle, and it would be premature to start a process of annual rate increases or decreases. (9 T 1603-1604; 1625-30).

3. Distribution Operations Capital Expenditures and O&M Expenses.

a. Distribution Operations Capital Expenditures.

Edison previously explained and supported its Distribution Operations capital expenditures (Edison Initial Brief, pp 60-63).

Staff proposes an $18.1 million reduction in capital reliability spending, which would reduce funding from $97.8 million to $79.7 million in 2011 (Staff Initial Brief, pp 11-14). Staff's proposal should not be adopted because it would adversely affect customer satisfaction, and not reduce overall costs. Mr. Whitman explained that capital reliability spending primarily funds pole top maintenance ("PTM"), and repetitive customer outage projects. The PTM program identifies and proactively replaces defective or damaged poles and pole hardware in a cost-efficient manner, typically with no interruption in customer service. If material must be replaced or repaired reactively, customers will likely experience outages, and the work will require additional expediting costs, such as overtime for the responding crews. The repetitive outage program is designed to improve reliability for pockets of customers experiencing five or more

revenue requirement, based on the estimated $1.3 billion total cost of decommissioning Fermi 2 in 2009 dollars, the Commission-approved 6.0% escalation rate, a 7.0% after-tax earnings rate on the decommissioning fund, and an assumed 35-year remaining life).

outages in a 12-month period. Any cuts in these programs will directly affect reliability, and result in more and longer outages for customers. Edison does not want customer satisfaction to suffer, which could be the result of the proposed reduction (6 T 394-96, 398, 400).

Staff reasons that Edison's reliability spending should be maintained at historic averages based on Edison's good benchmarking positions associated with frequency of interruption (Staff Initial Brief, pp 11-13). Some customers and leaders in southeastern Michigan have higher expectations, however, and the funding that Staff proposes to reduce is specifically targeted at addressing overall system reliability and the repetitive outage areas that were the focus of Case No. U-14603. Edison's proactive reliability efforts to maintain customer satisfaction are prudent efforts to avoid the Commission and Edison having to react to negative public opinions that would result from reliability degradation (6 T 396-97).

Staff suggests that Edison already has a very strong PTM program, and that any increase in spending for this program would not be prudent at this time (Staff Initial Brief, p 13). Staff further suggests some confusion between Edison's PTM program and its repetitive outage program (*Id*, p 14). The record demonstrates that if Staff's proposed funding reduction were applied to PTM, then the inspection program would lengthen to a 14-year cycle, which is well beyond the 10 to 12 year cycle recommended in the March 2010 pole inspection report. If the reduction were taken from the repetitive outage program, then projects impacting approximately 37,000 repetitive outage customers could not be funded. With more outages, the outage duration would also lengthen due to the limited availability of crews to make repairs. The proposed reduction in capital reliability spending would not reduce overall costs. If broken equipment is not repaired proactively, then it will ultimately be repaired on an unplanned basis, likely at higher costs (6 T 398-400).

The AG indicates support for its witness Mr. Coppola's allegedly "more reasonable" Distribution Operations capital expenditures, but provides no discussion about them (AG Initial Brief, p 26). For brevity, Edison incorporates by reference its prior discussion demonstrating that Mr. Coppola's proposals should be rejected (Edison Initial Brief, pp 62-63).

b. Distribution Operations O & M Expenses.

Edison previously explained and supported its Distribution Operations O&M expenses (Edison Initial Brief, pp 63-64).

The AG, without any explanation of its position in its Initial Brief, unrealistically suggests that inflation adjustments and wage increases are unnecessary (AG Initial Brief, p 32). The AG neglects to recognize that a major portion of the fluctuation in Distribution Operations O&M expenses is due to the variation in restoration expenses, which vary considerably with the weather. Distribution Operations has reduced staffing by 19% since 2005. Edison is seeking wage and inflationary increases that typically represent contractual obligations that Edison must honor. Even though Distribution Operations is subject to contractually obligated labor increases that exceed general inflation rates, O&M was only increased by the general inflation rate (6 T 391, 401-402).

c. Advanced Metering Infrastructure ("AMI") Expenses.

Edison previously explained and supported its recovery of the expenses associated with its Advanced Metering Infrastructure ("AMI") project, including an update on the progress made with the AMI program, and discussions of the expected benefits to utility customers and Edison's detailed cost/benefit analysis (Edison Initial Brief, pp 64-71).

Edison witness Mr. Sitkauskas further testified that Edison's SmartCurrents program spans three interrelated "smart" programs (AMI, Smart Home, and Smart Circuit), and their supporting Information Technology ("IT") systems. In 2009, Edison submitted its Smart Grid

Investment Grant ("SGIG") application to the DOE for SmartCurrents. The AMI program enhanced the grant application, and likely led to Edison being awarded the grant. All monies from the grant are 50% matched and payable by the United States government after Edison incurs the expense. Edison has pledged $76.2 million, and will receive an additional $7.7 million of in-kind contributions for products and services pledged by various Edison partner companies, yielding a total grant of $83.9 million (7 T 678-81, 694).

Staff recommends that Smart Circuit and Smart Home costs be included in rate base as Construction Work in Progress ("CWIP") with an AFUDC offset, based on concerns about timing differences between the costs and benefits of those programs (Staff Initial Brief, pp 101-102, 104, 116-17). Edison disagrees because its investments in these programs are reasonable and prudent. Smart Circuit technologies have already been installed and are providing current benefits to customers, and Smart Home uses proven technologies, with the remaining "pilot" component being customers' receptivity to new information, which is beyond Edison's direct control. Therefore, the expenditures for both programs should be included in rate base as Plant-in-Service, not CWIP (7 T 705-706).[43]

Edison seeks to recover AMI net capital expenditures of $21.9 million for 2010, $40.4 million for 2011, and $5.6 million for the first three months of 2012 (7 T 684; Exhibit A-9, Schedule B6.6, columns (f), (j), and (n), respectively). Mr. Sitkauskas explained the six line items constituting AMI capital expenditures (Meters, Network, Disconnect Modules, PMO, IT and Contingency/Corporate Overhead), and supported total project costs of $33.6 million in 2010, $57.9 million in 2011, and $14.9 million in the first three months of 2012. These total

[43] Edison also disagrees with Staff's recommended 13,000 to 26,000 sample size for these programs (11 T 2219). The DOE's Technical Advisory Group (TAG") helped Edison to determine the optimal size of the treatment groups. The final sample size of each treatment group was determined to be 375, and the DOE approved this sample size. Therefore, Edison recommends using this sample size (7 T 707).

costs are offset by matching funds from the DOE grant and in-kind contributions from third-party vendors, yielding the net capital expenditures that Edison seeks to recover in this case (7 T 681-84). Using the same format, the net capital expenditures for Smart Circuit are $4.8 million in 2010, $0.6 million in 2011, and $0 for the first three months of 2012; and the net capital expenditures for Smart Home are $1.3 million for 2010, $1.4 million for 2011, and $0 for the first three months of 2012 (7 T 384; Exhibit A-9, Schedule B6.6, lines 12-13, and 16-17).

AMI's O&M expenses consist of meter and information technology expenses associated with installing AMI, plus Edison's costs for communication and education related to AMI benefits and the installation process (Exhibit A-10, Schedule C5.13, lines 1-12). These expenses are partially offset by O&M savings (Exhibit A-10, Schedule C5.13, lines 13-28), the majority of which relate to meter reading expenses (7 T 684-85).[44]

Exhibit A-18, Schedules J1 and J2 provide the cost/benefit analysis of the full deployment of AMI throughout Edison's and MichCon's service territories. Mr. Sitkauskas explained that it is appropriate to review costs for both utilities in order to properly evaluate the cost/benefit of the AMI project. Health and pension benefits and payroll taxes are included in the cost/benefit analysis in order to properly account for the total costs and benefits of AMI; however, Edison is requesting recovery of AMI-related benefits and payroll taxes outside of the direct AMI cost recovery request (7 T 685-86).

Edison's cost/benefit analysis demonstrates that the benefits provided to customers of DTE's SmartCurrents and AMI programs outweigh the costs. The program's net present value of approximately $82.9 million reflects the savings exceeding costs over the life of the program.

[44] Edison expects that a review of capital and operating expenses will be appropriate in subsequent rate case proceedings as additional AMI meters are installed during future phases of deployment (7 T 721). Edison does not presently seek to recover the remaining AMI costs for periods beyond March of 2012, since they will be incurred outside of the projected test period. In this case Edison anticipates the recovery of those remaining costs in subsequent rate cases, as the Commission ruled in Case No. U-15244, and reserves all rights to recover these, and any additional unrecovered costs, in a subsequent rate case or through some other lawful and reasonable means.

The steady-state savings rate at full deployment is projected to be $60.8 million in 2018 dollars (7 T 686; Exhibit A-18, Schedule J2). Mr. Sitkauskas outlined how AMI savings were determined, achieved, and updated (7 T 686-91). He concluded by summarizing the cost/benefit analysis of the AMI project, and supporting the AMI project as a reasonable and prudent use of utility resources as follows:

> "As shown on Exhibit A-18, Schedule J2, line 13, column (d), the AMI project has a capital outlay of approximately $455 million, of which Edison's contribution is $357 million and MichCon's contribution is $98 million. The total project has a net present value of $82.8 million ($34.7 million associated with Edison) with a combined payback at 15 years (16 years for Edison) based on a 30 year project life. This results in $60.8 million of steady state savings.
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> * * *
>
> "As the cost/benefit analysis shows, the benefits of the project (i.e., the savings attributable to the project) are expected to outweigh the costs of the project, for both Edison and MichCon. The results of this analysis are supported by the successful efforts of the company's AMI pilot programs, where the benefit categories were validated and many expected project benefits were realized. Based on these two factors, it is reasonable to conclude that the AMI program will have a positive impact on customers, and that the AMI investments continue to be a reasonable and prudent use of utility resources" (7 T 690-91).

Staff recommends that Edison recover $71,564,000 of its requested $74,958,000 AMI expenditures, based on the removal of $3,394,000 of contingency costs that Staff viewed as uncertain to occur (Staff Initial Brief, p 101; 11 T 2207-2208). Mr. Sitkauskas responded by explaining that the contingency amount is necessary and reasonable. The contingency amount has been fully accounted for, on payment of Michigan sales tax on meter hardware, and

upgrading the wireless network infrastructure in Oakland County. These are prudent and reasonable expenditures, so the contingency amount should be approved (7 T 695).[45]

Staff "supports rate recovery of Detroit Edison's projected AMI expenditures and Commission approval of full deployment with Staff's proposed recommendations herein" (Staff Initial Brief, p 96, with Staff's proposed recommendations continuing to p 118). Edison welcomes Staff's support for rate recovery, but disagrees with Staff's proposed recommendations because, as discussed in Edison's Initial Brief and above, Edison's request for approval is supported by a cost-benefit analysis, the successes realized during the pilot phase of the project, and the benefits to customers from full deployment. Staff's additional conditions are redundant, unnecessary, excessive, and/or premature (7 T 696-98). While many of the topics included in Staff's proposed eight conditions may eventually be part of a fully-developed Smart Grid effort, they are outside of the scope of Edison's current request (7 T 698). Mr. Sitkauskas specifically addressed each of Staff's proposed eight conditions, noting that Edison is not opposed to filing a report as suggested in proposed condition 5, or the general concept reflected in proposed condition 8, but neither of these proposals nor any of Staff's other proposed conditions should be a condition for approval of Edison's AMI request in this case (7 T 699-702).

Staff further recommends reporting requirements for AMI-related data (Staff Initial Brief, p 103. See also, AG witness Mr. McGarry at 9 T 1540). Edison believes there is merit in providing relevant AMI project data to the Commission as the project moves forward; however, Staff's and the AG's proposed requirements are unnecessary, excessive, and burdensome. Instead, Edison proposes that, since it will be requesting for recovery capital investment in

[45] Staff suggests that Edison "did not sufficiently substantiate its request" (Staff Initial Brief, p 111), but the record contains testimony that fully supports Edison's position. No further substantiation is necessary to support a decision by the Commission. *Great Lakes Steel v Public Service Comm*, 130 Mich App 470, 481; 334 NW2d 321 (1983).

subsequent rate case proceedings, updates of the cost-benefit analysis should be provided as part of those cases. Edison will continue to provide interim informational project updates to the Commission and Staff as requested, and will also provide to the Commission and Staff any reports that are submitted to the DOE highlighting Edison's progress in deploying the Smart Grid infrastructure (7 T 703-704, 720).

Staff made four adjustments to Edison's cost-benefit analysis, leading to an inaccurate suggestion that the net present value ("NPV") of AMI is negative (Staff Initial Brief, p 104-106; 11 T 2329-33). Mr. Sitkauskas explained that Staff's addition of a $10,803,000 contingency to cover unanticipated capital expenditures that may occur in the post-deployment period is based on the inaccurate assumption that Edison neglected to account for the reasonable possibility of early technical obsolescence or other equipment retirement. To the contrary, the contingency amount related to the unanticipated replacement of AMI meters that is already included in Edison's cost-benefit analysis is nearly twice Staff's recommended amount (7 T 708-709).[46] Staff's recommended shortening of the AMI meter life from 20 years to 15 years is based on three sources that do not provide a sound foundation for the recommendation. In contrast, the AMI meter's life is 20 years according to Itron, based on rigorous product testing which indicates that the average mechanical life of the Itron meter is longer than 20 years. Edison's depreciation study in Case No. U-16117 uses a 20 year life for AMI meters[47], and several utilities also use a 20 year life for AMI meters (7 T 709-12).[48] Staff's 10% reduction of theft

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[46] Staff suggests Mr. Sitkauskas incorrectly assumed that Staff's contingency was only for meter failures (Staff Initial Brief, p 17). Regardless of the scope of Staff's contingency, however, Edison's cost-benefit analysis still includes a contingency amount that is nearly twice Staff's recommended amount.

[47] The June 16, 2011 Commission Order in Case No. U-16117 (Detroit Edison's depreciation case which utilized a 20-year AMI meter life) ordered that "The Detroit Edison Company's proposed depreciation and net salvage methodologies are approved, as modified by the order." The Order did not reduce the life of AMI meters.

[48] Staff responds that it "does not necessarily disagree that mechanically, the Itron meters may last 20 years or even longer," but speculates that they could prematurely fail or suffer from technical obsolescence (Staff Initial Brief, pp 117-18). Edison maintains that the best evidence on the record supports a 20-year meter life.

benefits is based on the assumption that theft of electricity will continue after AMI deployment, based on unlikely scenarios that are not supported. Even when assuming that either of the scenarios was to occur, Staff offers no rationale for the assumption that theft benefits would be reduced by a magnitude of 10% (7 T 712-13).[49] While Edison agrees with Staff's removal of benefits associated with meter accuracy in the NPV calculation, if the NPV calculation is solely used to measure benefits provided to customers only, several changes made to the business case subsequent to Edison's initial filing partially offset the elimination of benefits associated with meter accuracy, with the resulting impact indicating that AMI is still NPV positive. As a result, Edison's requested recovery remains supported (7 T 714).

Staff further suggests that Edison did not perform an appropriate cost/benefit analysis, so the net benefit to Edison's customers remains unknown and Edison's cost recovery should be capped and further reviewed (Staff Initial Brief, pp 106-107, 112). Edison disagrees because its cost/benefit analysis complies with the Commission's January 11, 2010 Opinion and Order in Case No. U-15768, as Staff appears to acknowledge (Staff Initial Brief, p 100), and Edison's cost/benefit analysis demonstrates that the benefits to customers of the AMI program outweigh the costs, as discussed in Edison's Initial Brief and above. Contrary to Staff's assertion, after the initial filing Edison removed meter accuracy and made other adjustments so that the Company's analysis includes only those benefits that can be realized by customers. This analysis continues to show a positive NPV for the AMI project, which supports Edison's request for recovery.

Staff also states that if Edison pursues a "true Smart Grid program," which presumably means including a full deployment of supply-side programs, Edison will incur "significant" additional costs (Staff Initial Brief pp 100-101). Not only did Staff fail to provide any support

[49] Staff responds that "10% is a subjective estimate" based on its witness' professional judgment (Staff Initial Brief, p 118). Edison maintains that the 10% estimate has no tangible basis.

for this assertion, they also ignored their own claims that these supply-side programs may have benefits that exceed the benefits associated with AMI (11 T 2216).

Staff misstates Edison's position regarding future cost recovery if AMI were stopped before full deployment (Staff Initial Brief, pp 111-112). As Mr. Sitkauskas explained, all expenditures Edison made for AMI would be included in rate base as plant-in-service if they were "reasonable" since the benefits attributable to those expenditures would be passed back to customers (7 T 696).

Staff inappropriately uses its Initial Brief to introduce new technical positions not found in the record in this proceeding, even claiming that it "responds to the Company's rebuttal arguments" (Staff Initial Brief, p 113). Consequently, Staff's new arguments on pages 113 through 116 regarding the conditions it would like the Commission to impose on Edison should be disregarded. The following examples in Staff's Initial Brief contain no transcript reference supporting Staff's technical position:

> "While Staff recognizes that Detroit Edison already has a residential pilot in place for Dynamic Peak Pricing (DPP) as part of the DOE's SGIG, Staff believes the two year timeframe for the pilot to be incapable of measuring long-term persistence of customer behavior change. It would be highly risky to implement dynamic pricing programs on the basis of the results of short-term pilots, because these pilots may intrinsically overstate consumer response due the short time-frame" (Staff Initial Brief, p 113).
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> "Detroit Edison's lack of C&I programs will diminish the Company's competitiveness with third party providers of demand response and could cause a loss of AMI benefits that would otherwise offset project costs" (Staff Initial Brief, p 114).
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> Thus, it is reasonable for the Company to demonstrate to the Commission in its next rate case that it has provided the flexibility to rapidly respond to industry changes – during the course of deployment. This will minimize the risk of technological obsolescence that would be borne by Detroit Edison's customers as a result of the Company's decision to aggressively install AMI. (Staff Initial Brief, p 115).

There is no merit in ABATE's suggestion that since the additional potential benefits of demand response programs are unknown, "the Commission should suspend the AMI Program and require all interested intervening parties to develop a pilot program that will quantify any benefits that come from demand response" (ABATE Initial Brief, pp 22-24). Edison's investment in AMI is consistent with the Commission's prior rulings in Case Nos. U-15244 and U-15768, and fully supported by Edison's cost/benefit analysis. Any benefits from demand response programs would only provide further support for Edison's investment, so there is no sound basis to suspend the AMI program while waiting to quantify those additional benefits.

The AG suggests that AMI cost recovery would make current customers bear the costs for significant benefits to be received by future customers, so implementation costs should be deferred as a regulatory asset (AG Initial Brief, pp 27-28). The AG's suggestion lacks merit, and is not supported by his own analyses. The financial profile of the AMI project does not indicate an inter-generational inequity problem exists, let alone one that requires the use of a regulatory asset (7 T 715-18). Staff also properly opposes the AG's regulatory asset proposal (Staff Initial Brief, pp 107-108).

4. Fuel Supply and Midwest Energy Resources Company Capital Expenditures and O&M Expenses.

Staff agrees with Edison's proposed MERC expense. (Staff Initial Brief, p 46) Edison previously explained and supported its Fuel Supply and Midwest Energy Resources Company ("MERC") capital expenditures and O&M expenses for 2009 through the projected period ending March 2012 (Edison Initial Brief, p 72).

AG witness Mr. Coppola incorrectly recommended a $2.8 million reduction to MERC O&M (10 T 1773; without further discussion the amount was inaccurately referenced as $28 million in AG Initial Brief, p 35). Ms. Uzenski explained that the starting point for his analysis was incorrect because there must be an offset to MERC O&M so that MERC's net income is

reduced to zero. MERC returns its profits to Edison's customers in the PSCR process. If the O&M offset were not included in the base rate net operating income calculation, then MERC's profits would inappropriately be credited to customers twice (7 T 1134-36).

5. Administrative and General Capital Expenditures.[50]

Edison previously explained and supported its capital expenditures for the Corporate Staff Group ("CSG") and the Customer Service, Regulated Marketing, Revenue Management and Protection ("RM&P"), and Electric Choice organizations (Edison Initial Brief, pp 72-74).

The AG again vaguely references, without discussion, its witness Mr. Coppola's allegedly "more reasonable" suggestions (AG Initial Brief, p 26). Edison incorporates its prior discussions describing a capital portfolio of discrete projects and demonstrating that Mr. Coppola's suggestions lack merit and should be rejected (Edison Initial Brief, p 73).

6. Administrative and General O&M Expenses.

Edison previously explained and supported its O&M expenses for the CSG and the Customer Service, Regulated Marketing, RM&P, and Electric Choice organizations (Edison Initial Brief, pp 74-76)

Staff excluded $3.4 million of salary increases within CSG based on the use of an annual escalation of inflation of 1.59% for 2011, and 1.92% for 2012, based on the Consumer Price Index (Staff Initial Brief, p 33; 11 T 2275).[51] While Staff is correct that the Commission has used the CPI-U to determine inflation rates to be used in rate cases (Staff Initial Brief, p 34), Staff neglects to recognize that the Commission has declined to use Staff's inflation rates where a large part of Edison's requested recovery is based on contractual increases for labor expense

[50] Administrative and General includes Edison's Corporate Staff Group ("CSG"), Customer Service, Regulated Marketing, Revenue Management and Protection ("RMP") and Electric Choice.

[51] Staff did not disagree with labor increases in other A&G related organizations (Customer Service, Regulated Marketing, RM&P, and Electric Choice).

related to union contracts (January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, p 38).

Edison's projection of A&G-related salary costs (for the CSG organization) incorporates a 3.0% annual escalation to be consistent with salary increases by other employers. A recent Towers Watson U.S. Salary Budget survey for non-represented employees reflects salary increases of slightly more than 3.0% by comparable companies in 2011/2012. (7 T 858-59, 8 T 1331-32). Therefore, Staff's O&M should be adjusted for $3.4 million (see Reply Brief Attachment A, page 2) as Edison's costs of paying its CSG employees are fully justified and should be approved.

The AG proposes the total exclusion of any wage and inflationary increases in A&G (AG Initial Brief, pp 34-35). Edison disagrees. In addition to the discussion above, Mr. Broome explained that while the level of uncollectible accounts has decreased, it is still imperative that the RM&P department continue to be diligent in its collection efforts, since uncollectible accounts in its service territory are consistently higher than the accounts of other utilities with similar demographics. In addition, the Customer Service and Regulated Marketing organizations are labor intensive. Edison has planned for nominal wage increases of 3%; however, Edison's recovery request is 1.5% for 2010, 1.4% for 2011, and 2.0% for January 1 through March 31 of 2012, based on the Consumer Price Index. Thus, Edison's request for recovery is reasonable and should be approved (8 T 1340-41, 1343-44).

The AG suggests a $534,000 reduction to forecasted insurance expense related to a refund from the Nuclear Electric Insurance Limited ("NEIL") company (AG Initial Brief, p 35; 10 T 1773-74). Ms. Uzenski explained that the suggestion should be rejected because it is based on an average 2007 through 2009 refund of $2.1 million, which is less predictive of future refunds than Edison's use of the 2009 historical amount, adjusted for inflation. For example,

Edison's NEIL refund for 2010 was $1.1 million. Therefore, the Commission should use Edison's original NEIL forecast credit of $1.5 million (7 T 1136).

7. Uncollectible Accounts Expense.

Edison previously explained its projected uncollectible expense of $72.9 million for the projected test year (Edison Initial Brief, pp 76-78).

Staff witness Mr. Welke testified: "Staff recommends a projected uncollectible expense of $55,889,143. This projection is the Company's actual 2010 uncollectible expense, less charitable deductions" (11 T 2272), and "Staff removed expenses for low income match write offs, which are charitable donations, from the uncollectible expense because including these expenses would place ratepayers in the position of becoming involuntary contributors to charity" (11 T 2274).

Staff now acknowledges that it "mistakenly concluded that the Company's low income matching program was a charity, when in fact it is a Company program to reduce uncollectible expense. Thus, Staff removed an amount of $2,065,493. Therefore, Staff recommends a projected uncollectible expense of $57,954,636" (Staff Initial Brief, p 44. See also, *Id* at 33). The AG recommends an uncollectible expense of $63.7 million (AG Initial Brief, p 35), which is based on a five-year ratio of charge-offs to electricity sales (10 T 1782).

Staff's continuing proposal to use 2010 actual uncollectible expenses, and the AG's proposed five-year ratio are both inappropriate to estimate uncollectible costs for the projected test period because LIHEAP funding increased approximately 150% during 2008 through 2010, which correlates to the decrease in uncollectible expense. In light of the proposed further reductions in Federal low income funding and the continued pressure on various cities and

towns, which are increasingly in financial hardship, Edison continues to recommend uncollectible expense of $72.9 million for the projected test year (8 T 1339).[52]

Staff references Mr. Stanczak's testimony in Case No. U-15768 to suggest that Edison is being inconsistent (Staff Initial Brief, pp 43-44). Staff's suggestion is unpersuasive because it neglects to mention that the testimony was in the context of moving away from a multi-year average due to skyrocketing expenses that reached $87 million in 2008 due largely to the economic downturn (See, for example, January 11, 2010 Opinion and Order in Case No. U-15768, p 57).[53] Here, in contrast, Edison observed that its uncollectible expense decreased to $77 million in 2009, and appropriately projected a further reduction to $72.9 million in the projected 12 months ending March 31, 2012 (8 T 1327). As noted above, this case must be decided on its own record, and Staff's references to evidentiary materials beyond that record do not provide a sound basis for a decision by the Commission.

Accordingly, the Commission should adopt Edison's $72.9 million recommendation rather that Staff's $58 million recommendation (an adjustment of $14.9 million as reflected on Edison Reply Brief Attachment A, page 2), or the AG's $63.7 million recommendation. As discussed in section VIII.D of Edison's Initial Brief and further explained below, however, if the Commission adopts an uncollectible expense level below $72.9 million, then Edison proposes to retain its existing uncollectible expense tracking mechanism.

[52] Utility rates are to be set prospectively and to reflect the costs of providing utility service at the time the rates will be in effect. *ABATE v Public Service Commission*, 208 Mich App 248, 257-258 (1994); *Board of Public Utility Comm'rs v New York Telephone Co.*, 271 US 23; 46 S. Ct 363; 70 L. Ed. 808 (1926).

[53] In Case No. U-15244, the Commission used a three-year average of actual net charge-offs as a percentage of operating revenues ("three-year average") to establish the level of uncollectible expense reflected in rate relief. In Case No. U-15768, Edison proposed the same UETM that the Commission approved for MichCon in Case No. U-13898.

8. Edison Should Be Allowed to Recover Its Projected Employee Benefit Expenses.

Edison has supported $345.1 million of net O&M employee benefits expense (Exhibit A-10, Schedule C5.9) throughout the evidentiary phase of this proceeding. However, for the purpose of reducing issues in dispute, Edison has reduced its projected net O&M employee benefits expense to $282.3 million to reflect Staff's updated projections for pension and OPEB expense.[54]

a. Pension.

Edison previously explained the development of its projected pension expense (Edison Initial Brief, pp 79-80). Based on the updated projections relied upon by Staff, Edison's annual pension costs are expected to increase from $73.6 million in the historical test period (Exhibit A-10, Schedule C5.9) to $147.0 million in 2011 (Exhibit A-32, Schedule JCW-1).

The AG suggests that Edison's as-filed pension costs should be reduced by $34.3 million (AG Initial Brief, p 36; Exhibit AG-15). Based upon the Company's initial pension cost projection of $170.9 million for the projected test year, which is the starting point of the AG's recommendation, the impact of Mr. Coppola's proposed pension cost reductions of $34.3 million results in a 2011 pension cost of $136.6 million. This proposal reflects that a substantial portion of Mr. Coppola's proposed adjustments relate to updating of assumptions for the assumed return on assets in 2010 and the discount rate. Thus, the remaining amount in dispute is the difference between the comprehensive actuarial analysis of the Company's projected pension costs created by the Company's external actuary of $147.0 million, as adopted by both the Company and Staff, and the $136.6 million sponsored by Mr. Coppola, which has been cobbled together from a variety of sources and assumptions (7 T 850). Accordingly, the AG's proposed pension

[54] See Edison Initial Brief Attachment A, page 5 for revised Employee Benefit costs related to Edison adopting Staff's position with respect to pension and OPEB costs.

adjustments should be rejected because they are both incomplete and based on flawed assumptions (7 T 850-52) and Edison has already updated its pension costs based on projections relied upon by Staff that already reflect updates to discount rates and actual return on assets assumptions (7 T 850).

b. Other Post-Employment Benefit ("OPEB") Expenses.

Edison previously explained the development of its OPEB costs (Edison Initial Brief, pp 81-82). Based on the updated projection relied upon by Staff, Edison's OPEB costs are projected to decrease from $162.2 million in the historical test period (Exhibit A-10, Schedule C5.11) to $120.1 million in the projected period (Exhibit A-32, Schedule JW-1).[55]

The AG implies in its Initial Brief that OPEB costs, similar to the pension issue, should be reduced by $73.5 million for the impact of updated assumptions as quantified by Mr. Coppola, and further claims that the Company's OPEB costs should be reduced by $27.0 million for the impact of the Company's alleged OPEB funding relative to OPEB costs collected in rates. (AG Initial Brief pp 36-37) The sum of the OPEB issues raised by Mr. Coppola and argued by the AG would decrease Edison's OPEB costs by $100.5 million from the $183.4 million reflected in the Company's initial projection (Exhibit AG-15). The $73.5 million of OPEB adjustments was derived through a combination of sources and estimates compiled by Mr. Coppola based on his proposed cost assumptions. This approach is clearly inferior to an actuary's professional analysis that recognizes the complexity and interdependencies of the models required to produce reliable and credible estimates, which both the Company and Staff have adopted (7 T 850). Therefore, the AG's claimed OPEB cost reduction for updated assumptions of $73.5 million should be rejected.

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[55] See Initial Brief Attachment A, page 5 for revised OPEB costs related to Edison adopting Staff's April 1, 2011 filed position.

The AG's remaining proposed $27 million OPEB cost reduction is premised on an analysis prepared by Mr. Coppola on Exhibit AG-18, where the AG asserts that the Company has failed to externally fund its OPEB liabilities in accordance with the Commission's mandate contained within its Order in Case Nos. U-10040 and U-10040-A (AG Initial Brief, pp 36-37). As a consequence of this alleged underfunding derived by Mr. Coppola, the AG imputes a $27 million reduction in the Company's projected OPEB costs.[56] The AG's reduction to projected OPEB costs should be rejected because the analysis prepared by Mr. Coppola is fundamentally flawed. Moreover, any adjustment to projected OPEB costs related to any funding shortfall must also recognize the impact on the Company's revenue requirement as a result of an increase in the Company's Working Capital (7 T 854). Mr. Coppola fails to recognize such impact. Accordingly, even if Mr. Coppola's calculation of the Company's funding relative to OPEB costs collected in rates were correct, which it isn't, he has inaccurately computed the effect of any imputation of additional OPEB funding on the Company's revenue requirements. An explanation of the flaws inherent in the OPEB funding analysis reflected on Exhibit AG-18 Revised, the relationship of OPEB funding to the Company's Working Capital requirements and the impact on the Company's revenue requirement of the AG's proposal is provided below.

The direct testimony of Mr. Coppola asserts that Exhibit AG-18, is a comparison of the Company's external funding of its OPEB liabilities with the level of OPEB expense included in the Company's rates for the years 2005 through 2010. This analysis reflected cumulative OPEB funding by the Company of $318.0 million based on Mr. Coppola's interpretation of the disclosures contained in the Company's annual reports to the Securities and Exchange Commission on its Form 10-K compared to the cumulative annual OPEB expense included in rates of $638.7 million based on his interpretation of Commission Orders for 2005 through 2009

[56] Of the $27 million in imputed OPEB cost reduction Mr. Coppola assigns $20 million as a reduction to O&M expense and $7 million as a reduction to capital expenditures (10 T 1792; Exhibit AG-15).

and a Company response to discovery for 2010. From this analysis, Mr. Coppola incorrectly concluded the Company had underfunded its OPEB liabilities by $320.7 million for the years 2005 through 2010. From this purported funding shortfall, Mr. Coppola then calculated a reduction in the annual OPEB cost based on the assumption that a $100 million increase in OPEB assets would increase the annual return on assets by $9 million, as Mr. Coppola derived from a Company discovery request (Exhibit A-33). Thus, Mr. Coppola increased the assumed return on OPEB assets, which reduced the projected OPEB cost, by presuming $300 million of increased OPEB funding by the Company (as rounded down from the derived $320.7 million reflected on Exhibit AG-18).

Company witness Wuepper testified on rebuttal that Mr. Coppola's calculations reflected on AG-18 were wrong because the amounts reflected as Company funding between 2005 and 2010 were actually $484 million, including $36.1 million funded in January 2011 related to 2010 (7 T 854-56). Additionally, Mr. Wuepper calculated the level of OPEB expense included in the Company's revenue requirements for the years 2005 through 2010 to be $519.5 million. Thus, the actual OPEB funding shortfall for the five year period was only $35.5 million[57] rather than the $320.7 million derived by Mr. Coppola. (Exhibit A-32 Revised, Schedule JCW-2) In contrast to Mr. Coppola's analysis, Revised Exhibit A-32, Schedule JCW-2 recognizes that for the years 2005 through 2008 the Measurement Date used in the OPEB related disclosures in the Company's annual Form 10-K filings to the SEC was November 30 and thus any Company

[57] This OPEB funding shortfall occurred in 2005. While prior to 2006 the Company's historic OPEB funding practice was to fund the annual OPEB expense incurred each year rather than the specific amount included in the Company's then effective rates, pursuant to a Settlement Agreement in Case No. U-14838 the Company agreed to fund to the level authorized for ratemaking per the Order in Case No. U-13808. Consequently, the Company funded $76 million in 2006. The Settlement Agreement in Case No. U-14838 also required the Company to submit a report of its OPEB funding practices in its next general rate case filing. That report was filed in Case No. U-15244. **While the Commission ultimately rejected the Company's interpretation of its OPEB funding obligation in its Order of December 23, 2008 in Case No. U-15244 (pp 31-32), the Company's funding of the level of OPEB expense included in rates for all years subsequent to 2006 has been in complete compliance with Commission's mandates.**

funding in December of any given year were reported as "December Adjustments" (7 T 854-5). Revised Exhibit A-32, Schedule JCW-2 properly reflects the actual post Measurement Date contributions for the respective years. The accuracy of the Company's OPEB funding between 2005 and 2010 is further corroborated by the detailed listing of Company contributions to the OPEB assets of $484.0 million, as reflected on Exhibit A-35.

Company witness Mr. Wuepper also explained in his rebuttal testimony that the amounts reflected on Exhibit AG-18 as OPEB expense included in rates during 2005 through 2008 as a result of the Commission's Order in Case No. U-13808 were wrong because the amounts used by Mr. Coppola were an inaccurate portrayal of the OPEB expense collected by the Company because such amounts were not reduced by the effects of the OPEB costs securitized and capitalized (7 T 854).

Mr. Coppola submitted surrebuttal testimony and a Revised Exhibit AG-18 that attempted to refute the accuracy of Mr. Wuepper's analysis. First, due to certain errors identified by Mr. Coppola in his initial development of the analysis on Exhibit AG-18, the Company's OPEB funding increased to $372 million, or $54 million more than the amount reflected on the original AG-18. But, more surprisingly, Mr. Coppola claimed for the very first time that the OPEB costs used in comparing OPEB funding to OPEB expenses collected in rates should be based on the gross OPEB cost, without regard to any reductions in those costs for the effects of the OPEB costs securitized and capitalized (10 T 1868-9).[58] Thus, instead of reflecting $638.7 million of OPEB expense included in rates, as per the original Exhibit AG-18, Mr. Coppola increased the OPEB expense included in rates to $720.6 million, or an increase of $81.9 million (Revised Exhibit A-18). The net effect of the $54 million increase in Company funding due to

[58] The Company opposed the admission of the Mr. Coppola's surrebuttal testimony (6 T 108 - 110). The surrebuttal was admitted over the Company's objection. The Company renews its objection Mr. Coppola's surrebuttal testimony, related exhibits and the AG's briefs relying upon that evidence.

Mr. Coppola's error correction and the increase in the OPEB cost included in rates of $81.9 million increased Mr. Coppola's calculation of the OPEB funding shortfall from $320.7 million to $348.6 million.

However, Mr. Coppola's Revised Exhibit AG-18 continues to ignore both the "December Adjustments"[59] and the January 2011 contribution related to 2010 and thus understates the Company's actual OPEB funding between 2005 and 2010. Since the actual cash disbursements reflected on Exhibit A-35 provides the most uncontroversial measure of the Company's actual OPEB funding, it is worthwhile comparing these cash disbursements to the recap of OPEB funding as summarized on both Mr. Coppola's Revised Exhibit AG-18 and Mr. Wuepper's Revised Exhibit A-32, Schedule JCW-2. A recap of the Company's OPEB funding from these three exhibits is reflected in the following table.

Exhibit A-35			Revised Ex. A-32, Sch. JCW-2			Revised AG-18
Contribution Date	Amount	Plan Year	Measurement Date Pre	Post	Total	Total
December 31, 2004	$40.0	2005	$40.0	$0.0	$40.0	$40.0
March 24, 2006	$40.0	2006	$40.0	$0.0	$40.0	$40.0
December 20, 2006	$36.0	2006	$0.0	$36.0	$36.0	$36.0
Total 2006	$76.0		$40.0	$36.0	$76.0	$76.0
December 27, 2007	$76.0	2007	$0.0	$76.0	$76.0	$0.0
December 24, 2008	$76.0	2008	$76.0	$0.0	$76.0	$76.0
December 23, 2009	$90.0	2009	$90.0	$0.0	$90.0	$90.0
December 28, 2010	$89.9	2010	$89.9	$0.0	$89.9	$90.0
January 10, 2011	$36.1	2010	$36.1	$0.0	$36.1	$0.0
Total 2010	$126.0		$126.0	$0.0	$126.0	$90.0
Total	$484.0		$372.0	$112.0	$484.0	$372.0

[59] It is not surprising that Mr. Coppola's Revised Exhibit AG-18 fails to accurately reflect the effects of the December Adjustments since his revised exhibit was submitted prior to the Company's response including the details of the December Adjustments and thus his revised exhibit didn't reflect such information. Moreover, upon cross-examination, when asked about the elements of the December Adjustments as provided in response to a discovery request, Mr. Coppola stated that he was unable to make "heads or tails out of" such information (10 T 1883).

While both Exhibit A-35 and Revised Exhibit A-32, Schedule JCW-2 reflect total OPEB funding of $484.0 million for Plan Years 2005 through 2010, the OPEB funding reflected on Mr. Coppola's Revised Exhibit AG-18 understates the Company's actual OPEB funding by $112.1 million. This difference in these amounts can be reasonably assumed to be the sum of the Post Measurement date funding in December 2007 (the last year that the Measurement Date was November 30) of $76.0 million and the Company funding of $36.1 million in January 2011 related to the 2010 plan year. Since the $484.0 million of OPEB funding for the years 2005 through 2010 accurately reflect the effects of the "December Adjustments" and is corroborated by a detail of the specific disbursements, it is clear that the Company's calculation of its cumulative OPEB funding for the years 2005 through 2010 is a far more reliable measure of actual funding during that period than the OPEB funding erroneously derived by Mr. Coppola.

Regarding the determination of the level of OPEB expense recovered in rates, Mr. Coppola makes both an untimely and inaccurate argument that the more meaningful measure of the adequacy of the Company's OPEB funding is relative to the total OPEB costs implicit in the Company's approved revenue requirements rather than the actual OPEB expense collected by the Company[60]. This view is not only both at odds with the Company's clear and unambiguous funding policy but is also fundamentally unreasonable. Since 2006 the Company has consistently funded its OPEB liabilities based on the OPEB expense included in the Company's revenue requirements. This is clearly reflected in Revised Exhibit A-32, Schedule JCW-2. Moreover, as more fully described below in the Company's response to Staff's Initial Brief, there is no reasonable basis to interpret the Commission's OPEB funding mandate from its Order in

[60] While a potentially subtle distinction, it is important that the difference between OPEB costs and OPEB expense be clear. OPEB costs are the measure of the periodic cost as developed by the Company's actuaries. In contrast, OPEB expense represents the portion of the OPEB costs that are allocated to the Company's O&M expense, net of costs securitized and capitalized. Since the OPEB expense allocated to O&M is reflected in the Company's revenue requirements, it is the only portion of the Company's OPEB cost recovered simultaneous with its recognition.

Case No. U-10040 to require the funding of the total OPEB cost rather than the net OPEB expense actually recovered in rates. First, Mr. Coppola's claim that the OPEB costs securitized will be eventually collected in rates (10 T 1868) is a conclusory assertion that is unsupported by the record, as demonstrated by Mr. Coppola's lack of understanding of how the OPEB costs securitized would be collected by the Company (10 T 1898-99).[61] Accordingly, Mr. Coppola's disregard for the aptness of a reduction in the Company's OPEB cost for the OPEB costs securitized should be rejected. Second, Mr. Coppola opines that the portion of OPEB costs capitalized should also not be reduced from the gross OPEB costs to determine the OPEB expense collected is similarly meritless. Since the Company only recovers the portion of OPEB costs capitalized as an element of future depreciation expense, if one assumes a 30 year depreciable life of Edison's Plant in Service, the OPEB cost capitalized would be recovered by the Company over 30 years (10 T 1899). Based on Staff's projection of OPEB costs capitalized of $29.5 million and a 30-year depreciable life, the full year depreciation expense included in the Company's revenue requirement would only be $1.0 million. Based on a half year convention of determining depreciation expense on recent additions to plant the depreciation expense collected by the Company pertaining to OPEB costs capitalized would only be $0.5 million in 2011. Since the amount of OPEB expense quantified by Mr. Wuepper is based on total projected OPEB expense without regard to any reduction for the Company's jurisdictional factor, any increased OPEB funding requirement for the annual depreciation on the OPEB costs capitalized would

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[61] The regulatory asset related to the Company's transition obligation resulting from adoption of SFAS 106 that pertain to the Company's generation assets were approved as a "Qualifying Cost" as prescribed by PA 141 in the Commission's Order issued on November 2, 2000 in Case No. U-12478. As required both by PA 141 and the Commission's Order in Case No. U-12478, the proceeds from the sale of the transition obligation were used to both reduce existing long-term debt and the redemption of existing common equity. Since the proceeds for such sale were used to lower the Company's permanent capitalization, none of the proceeds were available to the Company. Due to the securitization of the transition obligation the Commission has consistently excluded the costs securitized in the adoption of the OPEB expense to be included in revenue requirements. Thus, there exists no opportunity for the Company to ever recoup the OPEB related transition costs securitized. Mr. Coppola's presumption to the contrary is simply wrong.

likely be offset by the reduction in OPEB expense for Staff's total revenue requirement jurisdictionalization factor allocation of 98.979% (Exhibit S-6, Schedule F-1, page 1, line 24, columns (b)/(a)).[62] While Mr. Coppola seems to presume that the Commission had adopted a funding obligation for all OPEB costs, without the benefit of any authoritative reference, it is clear from the Commission's Order in a Michigan Gas Utilities general rate case that the Commission has merely mandated that utilities are required to fund the OPEB expense as such expenses are collected in rates.

> "The Commission finds that the language in the December 2, 1992 order in Case No. U-11040 was intended to create external funds for costs when they collect related revenues in their rates" (March 27, 1997 Order in Case No. U-10960).

Since it is axiomatic that the only costs collected in rates are those expenses included in revenue requirements, there is no logical basis for Mr. Coppola's assertion that the measure of the Company's OPEB funding obligation is without regard to "whether" (as in the instance of OPEB costs securitized) or "when" (as in the case of the OPEB costs capitalized) the OPEB costs are actually collected by the Company.)

Even if one were to accept the incorrect premise proffered by Mr. Coppola that the Company has underfunded its OPEB liabilities by over $300 million and thus the Company's projected 2011 OPEB costs should be reduced by $27 million, Mr. Coppola's proposal ignores the offsetting impact of any increased OPEB funding on the Company's working capital requirement (7 T 855-6).[63] As described by Company witness Mr. Wuepper, any increased

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[62] Staff OPEB costs of $120.1 million less OPEB costs securitized $7.0 million and OPEB costs capitalized based on the 26.1% of benefit costs capitalized ($29.5 million) results in net OPEB expense of $83.6 million. Reduction for jurisdictional factor of 98.979% results in an OPEB expense recovered of $82.7 million or $0.9 million reduction in funding. This reduction in funding is less than the $0.5 million increase in funding associated with the impact on depreciation of OPEB costs capitalized.

[63] Mr. Coppola's imputation of reduced OPEB costs due to the presumption of an additional $300 million of OPEB funding also ignores the impact that any increased funding from 2005 through 2010 would have had on the Company's asset values used in the projection of the assumed return on assets within the Company's OPEB costs.

funding of its OPEB liabilities would increase the Company's Working Capital requirements since the increased funding would lower the Company's accrued OPEB liability (7 T 855-6). While OPEB assets are assumed to earn an annual return of 8.75% (7 T 820), the Company's proposed pre-tax cost of capital is 9.76% (Exhibit A-11, Schedule D1). Thus, a $300 million increase in OPEB funding, all other things being equal, would increase the Company's revenue requirement by $3.0 million ($300 X (9.76% - 8.75%))[64].

Finally, since any reduction in the Company's 2011 OPEB cost arising from any increase in Company contributions must have been accomplished by January 1, 2011 (Exhibit A-33), it is too late for the Company to be able to realize the benefit of increased OPEB assets in 2011, even if it were deemed proper.[65] Thus, the AG has proposed an OPEB cost level that is impossible to be incurred in the projected test period. The Commission previously rejected a similarly unreasonable proposal by the AG regarding pension and OPEB expenses, where it concluded:

That is, based on the comparison provided below, of the sum of the actual return on assets over that period of $161 million and the expected return on assets over the same period of $313 million, the Company realized an actuarial loss of $152 million over the six year period. (Exhibit AG-51)

	2005	2006	2007	2008	2009	2010	Total
Actual Return	$49	$70	$56	($189)	$99	$76	$161
Expected Return	58	49	54	58	42	52	313
Gain / (Loss)	($9)	$21	$2	($247)	$57	$24	($152)

Given the financial crisis of 2008, in which the OPEB assets realized a loss of $189 million or almost 30% of its beginning of year asset value, there is no reason to presume that a $300 million increase in OPEB funding would have resulted in $300 million in higher asset values in 2011. Moreover, Mr. Coppola has ignored the impact that the actuarial losses arising from the higher funding between 2005 and 2010 would have on the 2011 OPEB cost projections.

[64] An increase in the Company's revenue requirement would also result if the Commission adopted the Staff's proposed pretax cost of capital of 9.08% (Exhibit S-4).

[65] In his surrebuttal testimony, Mr. Coppola dismisses the need to increase the Company's Working Capital requirement for the effect of the $300 million increased OPEB funding because the Company has yet to make such increased contributions.(10 T 1870). There is no basis in fairness in the regulatory process to impute a level of funding of the OPEB liabilities while the direct impact of such funding on the Company's other costs are ignored. In contrast, Staff recognized the importance of reflecting the Working Capital impacts of any increased OPEB funding (Staff Initial Brief p 38).

> "The Commission finds that just and reasonable expenses are a legitimate piece of the Edison's revenue requirement. To deny the utility recovery of costs it is incurring during the period in which it will incur them would neither be just nor reasonable" (January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, p 45).

The soundness of the Commission's conclusion in Case No. U-15768 is no less applicable in this instance. The AG's proposal in this proceeding to reduce the Company's projected OPEB costs to reflect increased OPEB funding that has not and should not occur would lead to a level of OPEB costs not representative of the costs to be incurred during the period the rates are in effect. For all the reasons described above, the Attorney General's proposal to reduce the Company's OPEB costs by $27 million should be rejected.

Staff asserts that it now agrees with the AG's claim that the Company has not funded its external OPEB trust to the level it has collected in rates. (Staff Initial Brief, pp 37- 38) Nevertheless, Staff's Initial Brief opposes the AG's $27 million reduction in OPEB costs because the AG's proposal fails to address the impact on Working Capital and because any OPEB funding issues should only be addressed on a prospective basis (Staff Initial Brief, pp 38-39). While Staff states that it agrees with the AG's conclusion that the Company has underfunded its OPEB trusts, it appears that Staff's dispute is solely with the Company's exclusion of the OPEB costs capitalized in its determination of the OPEB funding requirement. (Staff Initial brief, p 38) Specifically, Staff argues that since the OPEB costs capitalized are not funded, the OPEB cost in future years is increased by the assumed rate of return on the lower OPEB trust asset balances. (Staff Initial brief, pp 37-38) Accordingly, Staff argues that the total OPEB cost of $120,123,000 should be funded without regard to any reduction for the 26.11% proportion of OPEB costs capitalized (Staff Initial brief, pp 37-38).[66]

[66] Since Staff's Brief makes no mention of the Company's continued reduction of the OPEB costs for the effect of the OPEB costs securitized and discusses exclusively the impact of the OPEB costs capitalized, it is presumed that

Staff's argument that its proposal to require the Company to fund the total OPEB costs without any reduction for the portion of OPEB costs capitalized is somehow consistent with prior Commission orders (Staff Initial brief, p 39) is unsupported by the record. Rather, as referenced above, the Commission has made clear that the obligation to externally fund the Company's OPEB liabilities is based on the OPEB expense collected by the utility in its rates. (See Order in U-10960) Since the only means to currently recover OPEB costs is through the inclusion of the OPEB expense in O&M, it is clear that the obligation to externally fund its OPEB liabilities is based on the OPEB expense adopted in the Company's revenue requirement. Moreover, the Company has also clearly explained in prior cases that its OPEB funding policy was based on the OPEB expense included within the Company's O&M.[67]

This policy reflects the fact that the Company's obligation to fund its OPEB liabilities should be proportional to the level of OPEB expenses it actually collects in rates. This Company policy is consistent with the Commission's explicit conclusion in its Order in the Company's 2008 rate case where the Commission stated:

> "The Commission finds Detroit Edison and Staff's projected 2009 OPEB expenses to be reasonable. Detroit Edison shall be

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Staff's proposal does not include a requirement that the Company fund the OPEB costs securitized, as Staff's benefit costs are recapped on Exhibit A-32, Schedule JCW-1. Thus, Staff's actual funding requirement would be $120,123,000 minus the cost securitized of $6,984,000 or $113,139,000.

[67] See, for example, Case No. U-15244 (Order dated December 23, 2008, p 29) where the Commission describes the Company's intention to fund $76 million annually in 2007, as more fully described in the Direct Testimony of Mr. Richard J. Lueders in that case. This planned funding represents the OPEB expense included in the rates approved by the Commission in Case No. U-13808 and, as shown on Revised Exhibit A-32, Schedule JCW-2, net of the OPEB costs securitized and reduction of 22.9% of the OPEB costs capitalized. Similar testimony was presented by the Company in Case No. U-15768 (6 T 1043) that described the Company's intention to externally fund $90 million in 2009, based on the net OPEB expense reflected in the revenue requirement adopted by the Commission in Case No. U-15244, which also comports with the amount reflected on Revised Exhibit A-32, Schedule JCW-2.

[68] Staff's Initial Brief incorrectly implies that the Company earns a return on its investment through the depreciation of the cost capitalized (Staff Initial Brief, p 38) but confuses the concept of return on investment (the cost of capital applied to the unrecovered investment) with the return of investment (recoupment of invested capital through the inclusion of depreciation expense). While the Company recovers its OPEB costs capitalized over the average remaining lives of its property, plant and equipment, which is about 30 years, it is allowed to earn its overall rate of return on its undepreciated investment. Thus, Staff's claim that the Company realizes a return on its investment through the depreciation of the OPEB costs capitalized is not correct.

> permitted to recover from ratepayers $89,879,000 in OPEB expense" (December 23, 2008 Opinion and Order in Case No. U-15244, p 32).

As is apparent from Revised Exhibit A-32, Schedule JCW-2, the OPEB expense adopted by the Commission in U-15244 is net of both the OPEB costs securitized and a reduction for the 29.1% of OPEB costs capitalized. Thus, it is clear that the Commission has recognized that the level of OPEB costs recovered in rates is based solely on the portion allocated to O&M expense.

Finally, since the portion of OPEB costs capitalized are not currently recovered in rates, there is no compelling reason to require the Company to currently fund OPEB costs that will be collected over 30 years as the capitalized costs are depreciated.[68] Imposition of this requirement would not only an adverse impact on the Company's cash flow, as the annual cash collected through rates for the OPEB expense included in O&M is less than the total OPEB costs required to be funded under the Staff's proposal, but would also increase the Company's future revenue requirements since the assumed rate of return on the OPEB assets of 8.75% would be less than the Company's 9.76% pre tax cost of capital. Thus, adoption of Staff's proposal would not only have a deleterious impact both on the Company's cash flow, with potentially adverse credit rating consequences, but would also increase customer rates. Accordingly, any proposal to require the Company to prospectively fund the total OPEB cost without reduction for the impact of the OPEB costs securitized and capitalized should be rejected.

[68] Staff's Initial Brief incorrectly implies that the Company earns a return on its investment through the depreciation of the cost capitalized (Staff Initial Brief, p 38) but confuses the concept of return on investment (the cost of capital applied to the unrecovered investment) with the return of investment (recoupment of invested capital through the inclusion of depreciation expense). While the Company recovers its OPEB costs capitalized over the average remaining lives of its property, plant and equipment, which is about 30 years, it is allowed to earn its overall rate of return on its undepreciated investment. Thus, Staff's claim that the Company realizes a return on its investment through the depreciation of the OPEB costs capitalized is not correct.

c. Active Health Care Benefits.

Edison previously explained and supported its costs to provide health care benefits to its active employees (Edison Initial Brief, pp 82-84).

Staff recommends reducing Edison's active health care benefit expense by $8.1 million, which it indicates was the result of using Edison's methodology but with actual 2010 expense amounts used as a base in lieu of the 2009 amounts the Company used as a base in its filing (Staff Initial Brief, p 39; 11 T 2268). Staff's recommendation should not be adopted because it is premised on an inaccurate assumption that actual 2010 expenses accurately represent future expenses. Edison's active health care costs are subject to annual variability because Edison is self-insured for the majority of its health care costs, so those costs vary with the degree to which its employees and their dependants receive medical services. The 2010 actual expenses were not representative of Edison's experience in recent years (7 T 846-47). More importantly, the Company annual escalation factor is derived from the Company's actual experience over recent years. Thus, as explained by Mr. Wuepper, use of 2010 actual expenses to project future year's expenses would require the use of an escalation rate higher than 8% (7 T 847). The Company's projection of active health care expenses reflects the appropriate integration of the 2009 expense base with the annual escalation. Staff's proposal does not.

Staff responds that actual 2010 expenses are exactly representative of experience in recent years (Staff Initial Brief, p 39), but neglects to recognize that 2010 is just one year. Staff further suggests that Edison is being contradictory in testifying that it has taken significant actions to reduce its health care costs in recent years, which Staff suggests are captured in the 2010 expenses (Staff Initial Brief, 39-40). Again, 2010 was just one of the "years" over which Edison has taken actions and incurred costs. The record demonstrates that 2010 actual expenses were not representative of Edison's experience in recent years, so projected expenses for the

projected period should be based on 2009 expenses, as Edison has done. (See required adjustment to Staff's active healthcare position reflected on Edison's Reply Brief Attachment A, page 2).

d. Other Benefit Costs.

Staff removed non-qualified pension and deferred compensation costs in their entirety by reasoning that "there is no discernable difference" between these expenses and expenses that the Commission has removed in prior cases (Staff Initial Brief, p 42). AG witness Mr. Coppola similarly averred: "I see no reason why the Commission should change its established policy and allow recovery of these costs" (11 T 1795-96). Edison acknowledges that the Commission has denied recovery of "incentive compensation" costs in recent cases. Edison's new customer-focused incentive compensation plan, which is designed to address the Commission's concerns, is discussed in Edison's Initial Brief and below. For purposes of this discussion, however, it bears emphasis that the majority of costs that Staff and AG suggest excluding are unrelated to incentive compensation. Instead, some non-qualified pension plan costs are the result of Internal Revenue Service ("IRS") limitations on benefits earned by employees that are deemed highly compensated under the U.S. Tax Code. Similarly, the costs of the Deferred Compensation program are purely a product of allowing certain members of management to reduce their tax costs by opting to postpone the receipt of a portion of their compensation. Therefore, $2.2 million of costs or approximately $1.6 million in expense (Reply Brief Attachment A, page 2) should not be disallowed (7 T 857-58).

e. Incentive Compensation.

Edison placed in the record in this case and previously explained in its initial Brief all of the details of the Employee Incentive Compensation Plan ("EICP"), which is a new-for-2011,

customer-focused, non-executive annual incentive plan that addresses the various concerns raised by the Commission in previous regulatory proceedings (Edison Initial Brief, pp 84-90).

Staff's recommended complete exclusion of EICP expenses, is based on past Commission disallowances of completely different plans, as well as the inaccurate reasoning that "Detroit Edison did not provide a comprehensive analysis demonstrating that the benefits of non-financial metrics included within the plan outweigh the costs" (Staff Initial Brief, p 40, citing 11 T 2270). Staff's position lacks any sound basis and is unsupported by the transcript page cited in Staff's Brief, which concerns a 2009 Rewarding Employees Plan ("2009 REP"), which is completely different than the new EICP proposed in this case. There is similarly no sound basis for Staff's contention that "the analysis provided by the Company was incomplete" (Staff Initial Brief, p 40, again citing 11 T 2270). Staff simply refuses to acknowledge the significant and detailed evidence to the contrary that is in the record, and therefore Staff's assertions are not a valid basis for a decision.[69]

Specifically, the record demonstrates that Edison's new EICP is markedly different than the 2009 REP. The record in this case demonstrates that the 2009 REP is no longer used by the Company, and is not part of or in any way related to Edison's proposed EICP which was developed in direct response to previous Commission disallowances (6 T 286-87, 308). Thus Staff references to and discussion of the 2009 REP are simply irrelevant to this issue and this case. Contrary to Staff assertions, the EICP does not include a single financial metric, but instead contains only metrics that directly benefit the customer. The EICP includes a detailed analysis quantifying the benefits provided to customers, and Edison's customer benefit analysis

[69] Staff's related suggestion that Edison's incentive plans be recorded in account 426.5 similarly lacks any sound basis and should be rejected (7 T 1132-33).

highlights that the total benefits provided to customers significantly outweigh the costs of the EICP (6 T 290, 303; Exhibit A-20, schedules L1 and L3).[70]

Mr. Brudzynski provided a detailed description of the design and mechanics of the new EICP, including the metrics used to track company performance, the method for setting Company performance level targets, and the conditions under which employees will receive incentive compensation payments. He described the nine metrics that are included in the plan,[71] and explained that for each metric, a "base" performance level and a "target" performance level are determined. Each base level is equivalent to an MPSC standard if one exists, but if there is no MPSC standard, then the base level is equivalent to the industry average. Similarly, if an industry average does not exist, then the base level is equivalent to the historical Company average. The target levels in the submitted plan reflect the 2010 targets set within Edison in late 2009, which were determined using actual 2009 performance, industry benchmarks, and stretch goals to ensure that Edison's customers are provided with incremental benefits each year. Detroit Edison's current 2011 EICP has been updated to reflect additional stretch targets, and the Company's 2010 performance. Payments under the EICP are conditioned on exceeding the base performance level on the metrics (6 T 287-95; Exhibit A-20, Schedule L1).

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[70] AG witness Mr. Coppola testified that "I applaud the Company's approach of taking a quantitative approach to show improved operating performance can result in financial benefits to customers" (10 T 1778). The AG does not articulate a position on the EICP in his Initial Brief. Mr. Coppola recommended, however, that the Commission disallow the recovery of EICP expenses due to his belief that the new EICP is "premature," and suggested a series of steps be taken before Edison may recover EICP expenses in future proceedings (10 T 1780-81). Mr. Coppola's recommendation lacks merit because Edison has already provided all of the details and rationale necessary for Commission approval of the recovery of EICP expenses (6 T 311). There is similarly no merit in Mr. Coppola's recommendation of seven unnecessary, inappropriate, and arbitrary changes to Edison's EICP (6 T 312-18).

[71] The nine metrics are: (1) System Average Interruption Duration Index ("SAIDI"), excluding Major Event Days; (2) Random Outage Factor ("ROF"); (3) Average Speed of Answer ("ASA"); (4) First Call Resolution for Bills, Outages, and Turn-ons/Disconnects/Restores ("TDRs"); (5) Meter Read Rate; (6) Occupational Safety and Health Administration ("OSHA") Rate – Detroit Edison; (7) MPSC Complaints – Detroit Edison; (8) Customer satisfaction rating – Residential; and (9) Customer satisfaction rating – Business. (6 T 287, 290-94; Exhibit A-20, Schedule L-1).

Corrected Exhibit A-26, Schedule DGB-1 shows that the corrected historical MPSC complaints are significantly higher than the figures that Edison submitted originally. As a result, the 2011 target level for MPSC complaints is lower (more aggressive) than recent MPSC complaint levels (6 T 315).

Mr. Brudzynski also defined and quantified the benefits that Edison provides to its customers under its EICP. The customer benefits are defined as incremental benefits to the customer that are a result of employee performance in excess of base performance (Commission standards, industry average or Company historical average) in the nine metrics. Benefits are quantified using a two-step process: (1) each metric is linked to a direct driver of customer benefit; and (2) the value of the benefits driver is determined, using publicly-available data sources, when available. Customer benefits are calculated as the difference between reaching the target metric level above the base metric level.[72] Mr. Brudzynski's cost/benefit analysis conservatively estimates that the EICP's benefits are approximately $124 million, which is more than five times the $23 million of EICP costs that Edison seeks to recover through rates. It is reasonable to expect that customer benefits are even greater than this estimate, since there was no attempt to quantify all the benefits that customers realize under the EICP, and conservative estimates were used when selecting the parameters for estimating benefits (6 T 288-89, 298-304).

Staff suggests that Edison's analysis is incomplete because benefits are not quantified for each and every metric (Staff Initial Brief, pp 40-41). Staff neglects to recognize that a metric can be important to customers, while evading specific quantification. Edison's conservative analysis underestimates benefits, and demonstrates substantial overall benefits to customers from the EICP (6 T 300-304). Moreover, based upon the Commission's prior statements regarding the EICP it is the total benefits of the EICP that should outweigh the costs of the EICP. The

[72] The five drivers of customer benefits are: (1) value to a customer of avoiding a one hour interruption of service; (2) a customer's avoided cost of spending an hour on the phone; (3) avoided incremental cost to the customer of MISO market purchases; (4) avoided direct and indirect costs of an injury; and (5) the incremental value realized by the customer due to higher satisfaction that is not reflected in rates. Eight of the nine metrics can be linked to one of these benefit drivers. Meter reading is the sole exception, so it was conservatively assumed to have no incremental benefit to the customer, and no cost-benefit value was attributed to it (6 T 300-303; Exhibit A-29, Schedule L2). Exhibit A-20, Schedule L3 shows the customer benefits associated with each metric using the five benefit drivers.

Commission has not advocated that every metric must have a quantifiable benefit that outweighs the corresponding cost associated with including that metric as part of the EICP (6 T 286).

Staff inaccurately asserts that the EICP contains financial metrics, and that Mr. Brudzynski's rebuttal testimony should be disregarded as contradictory (Staff Initial Brief, pp 41-42). Mr. Brudzynski presented detailed direct testimony explaining EICP payments to employees will be determined by a three-step process. First, the potential payment is calculated using the nine non-financial EICP metrics discussed in Edison's Initial Brief and above. Second, this potential payment is either not adjusted or reduced using a set of financial criteria. Financial criteria cannot increase the amount of the potential EICP for which Edison is requesting recovery. If financial criteria are not met, however, then the EICP payment can be reduced to a capped level in accordance with the Company's financial performance. This backstop is necessary to ensure the Company realizes its financial goals while providing superior performance in the nine non-financial metrics, which benefits customers by ensuring that Edison will be able to access market capital to operate efficiently and provide reliable service to its customers (6 T 295-95). Third, the potential payment from steps 1 and 2 is then distributed to Edison employees, and modified based on both the business unit's and employee's contribution in helping the Company meet its goals (6 T 296-98).[73]

Staff's final argument references Staff's position that Edison already has adequate reliability, and "questions the logic behind incentivizing reliability beyond levels already viewed as satisfactory" (Staff Initial Brief, pp 41-42). Staff neglects to recognize that going beyond adequate reliability is exactly what the Commission indicated that an incentive compensation

[73] This Individual Performance Modifier ("IPM") adjustment will not change the Company's overall incentive payment level, since for every increase in an incentive payment to an employee or business unit, there must be a corresponding decrease to another employee or business unit. In the event that performance following steps 1 and 2 results in overall Company EICP payment in excess of $23 million, due to superior performance beyond targeted levels, the excess will be funded solely by shareholders (6 T 296).

plan should do (See, for example, June 10, 2008 Opinion and Order in Case No. U-15245, p 32: "In the Commission's view, a customer focused, employee incentive plan should require that higher standards than the regulatory minimum must be met before a ratepayer payout is made"). Edison's EICP fully satisfies the guiding principles the Commission has indicated should be followed in creating an EICP: (1) the metrics for Company performance used in the EICP should measure performance that impacts the customer, where possible; (2) these metrics should be representative of the performance of the employees across the Company; (3) payment under the EICP should only occur if performance exceeds the requirements of Commission service quality rules; and (4) the benefits generated by the EICP must outweigh the costs of the plan that are recovered through rates (6 T 286-87).

In reviewing this request, it is also important to keep in mind that Edison's incentive programs are not additional compensation over and above what other companies pay for similar jobs. Instead, Edison's incentive compensation programs are one of two components that make up Edison's total annual compensation package, which is reasonable and prudent, and comparable to other companies competing for these same employees. Without the prospect of total annual compensation equal to the fixed plus the variable compensation components, Edison will not be able to attract and retain a highly-skilled workforce, or provide incentives for its employees to engage in activities that benefit customers. Edison's compensation framework and philosophy benefits customers by attracting and retaining employees who have the requisite skills and experience to ensure the delivery of quality customer service, and by recognizing and rewarding effective and efficient performance. This directly benefits all customers by providing a high level of service at a competitive cost, and provides incentives to focus future job performance on those activities that provide the most benefits to customers (6 T 285; 7 T 835-39).

It is also important to keep in mind that Edison's incentive compensation programs allow Edison to provide a lower level of base pay. If Edison were to eliminate the variable element of compensation, then Edison would need to provide a commensurate increase in base pay in order to attract and retain a highly-skilled workforce. This would increase the cost of benefits, like pension costs, 401(k) matching contributions, life insurance, and disability insurance, which are tied solely to base salaries. Moreover, paying compensation solely in salary would remove incentives for employees to provide superior service to customers and other constituencies that Edison serves. Annual incentives ensure that employees have an element of at-risk compensation that allows Edison to differentiate partly based on performance and allocate compensation to those employees that are most deserving. Incentive-based compensation is an important tool to drive performance improvement, particularly in a service-based industry like the utility industry. Incentive compensation is an essential component of Edison's total compensation package, in light of Edison's need to provide adequate total compensation and to drive performance that ultimately benefits Edison's customers. Therefore, the Commission should recognize that variable compensation is a cost-effective component of total compensation, and allow Edison's requested recovery (6 T 285; 7 T 835-36, 838).

Edison has demonstrated in detail that the customer benefits of its EICP significantly outweigh its costs. Therefore, the Commission should not modify the EICP, and it should approve Edison's request to recover in rates the $23 million of EICP costs as reflected on Edison's Reply Brief Attachment A, page 2.

9. Board of Directors Expenses.

Staff excluded $1.9 million of operating expenses relating to stock-based compensation for DTE's Board of Directors ("BOD") (Staff Initial Brief, pp 45-46; 11 T 2270-71). Edison witness Ms. Uzenski explained that the DTE BOD costs are legitimate costs that Edison should

recover from its customers, since the DTE BOD performs the management, control and oversight responsibilities for Edison. The costs that Edison pays for these services should be recovered in base rates. The stock-based payment for these services does not negate the necessity of the expense. Thus, the $1.9 million adjustment (Reply Brief Attachment A, page 2) should be rejected (7 T 1132).

C. Power Supply Costs.

Edison previously explained and supported its requests that the Commission approve (1) the Power Supply Cost Recovery ("PSCR") base that the Commission established in its December 23, 2008 Opinion and Order in Case No. U-15244, and (2) full urea cost recovery in the PSCR process (Edison Initial Brief, pp 90-91).

Staff indicates that it calculated a Total Fuel and Purchase power Expense for the test period of $1,420,408,500, incorporating the effects of Edison's recently-executed contract with the Detroit Public Lighting Department (Staff Initial Brief, pp 48-49). Edison agrees with Staff's adjustment related to Detroit Public Lighting Department.

MCAAA appears to have abandoned its witness Mr. Peloquin's suggestion that Edison should be required to present a cost/benefit analysis of the urea program, which was based on inaccurately reasoning that the decision to purchase NOx emission allowances versus utilizing urea is a simple cost/benefit analysis (11 T 2076). In any event, the suggestion lacks merit because it neglects to recognize that Edison holds air permits issued by the Michigan Department of Environmental Quality ("DEQ") that contain specific NOx emission limitations. Compliance with these permits requires meeting specific emission limit standards by operating Monroe's emission control equipment as designed. The permits do not allow the purchase of NOx allowances in lieu of compliance with emission limitations (6 T 481, 564-66, 574-76).

D. Tax Expenses.

The record supports and Edison previously explained its projected federal income tax ("FIT"), Michigan business tax ("MBT"),[74] municipal, and Property and Other Tax expenses for the projected test year (Edison Initial Brief, pp 92-93).

Kroger suggests that a preliminary assessment of bonus tax depreciation would cause a material reduction in rate base, which should be reflected through a reduction in Edison's revenue requirement (Kroger Initial Brief, pp 1-6). To the contrary, deferred taxes are included in the cost of capital at zero cost instead of as a reduction to rate base, and this is just one component of the capital structure, which makes the determination of the revenue requirement more complicated. Also, the preliminary estimate of the deferred income tax impact of bonus tax depreciation referenced by Kroger is on a calendar year basis, and does not represent the impact on deferred income taxes for the projected test period ending March 31, 2012. Moreover, the impact on the revenue requirement caused by a change in deferred income taxes related to bonus depreciation cannot be determined in isolation because of related changes to working capital, the capital structure, and net operating income (7 T 1013-14, 1021).

Kroger agrees that the calculation would be complicated, and suggests that the Commission should order Edison to submit the calculation in a compliance filing subsequent to the Commission's determination of Edison's revenue requirement (Kroger Initial Brief, p 4). It is unreasonable for Kroger to single out one issue and either request that Edison change its revenue requirement after a final order, or require Edison to participate in what would effectively be a single issue rate case, by requiring a post-Commission order compliance filing (8 T 1403-1404). Kroger responds by suggesting that single issue ratemaking would not occur where the issue is

[74] Staff employed a correct methodology in calculating the MBT, but two technical corrections are required, as reflected in Exhibit A-31, Schedule ML-1, which reduces Staff's total Michigan and municipal taxes by $367,000 (7 T 1012-13). Staff has adopted these technical corrections (Staff Initial Brief, p51).

suggested during a rate case (Kroger Initial Brief, p 4). Kroger's suggestion is inaccurate and irrelevant. The significant time period is after the Commission's final order, which is when Kroger wants the compliance filing. Thus, despite Kroger arguments to the contrary there would be single issue ratemaking. The impropriety of single issue ratemaking after the Commission's order cannot be avoided simply by raising the issue prior to the Commission's order.

Moreover, numerous matters change throughout the course of a rate case. It is inappropriate to "cherry pick" isolated bits of new information to suggest that Edison's rate recovery should be lowered, while ignoring offsetting matters that favor a greater recovery for Edison.[75] For example, the record reflected Edison's understanding that the Michigan business tax ("MBT") would likely be replaced by a new corporate income tax in early 2012 (7 T 1025). That new corporate income tax was in fact recently signed into law (2011 PA 38). Edison's analysis projects an increase in annual tax expense due to that new corporate income tax of approximately $12 million (7 T 1028-29).

Kroger's further suggestion that "Edison should have amended its filing to reflect an updated tax code" (Kroger Initial Brief, p 5) lacks merit because Edison is entitled to rate relief within 12 months after its filing, and 2008 PA 286 discourages case updates due to the 12 month time frame for case completion.[76] Therefore, the Company's due process rights would be violated if Edison were required to amend its filing, or if the Commission were to accept other parties' one-way (downward) updates.

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[75] Creating rates that recognize *reductions* in certain costs while ignoring the *increase* in other costs, violates the due process rights of utilities. The Michigan Supreme Court cited with approval the conclusions of a circuit court judge granting an injunction against such unlawful rates:

> "Certainly at first blush it would appear to anyone steeped in 'due process' considerations that it is grossly unfair to include certain items of decreased cost in rate determination while at the same time to exclude items of increased cost." *Michigan Consolidated Gas Company v Public Service Comm*, 389 Mich 624, 633; 209 NW2d 210 (1973).

[76] MCL 460.6a(3); January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, p 27.

Staff takes no position with respect to Kroger's suggestion for a single issue rate case. However, Staff does recommend that the Commission require Detroit Edison to treat Bonus Depreciation and Uncertain Tax Positions ("UTP" as discussed in more detail below in Section VII, E) similarly for ratemaking purposes (Staff Initial Brief pp 55, 57). Staff's suggestion fails to recognize that the UTPs originate in the periods before 2010 while Bonus Depreciation (resulting from the Small Business Jobs Act passed on September 27, 2010 and the Tax Relief, Unemployment Insurance and Job Creation Act of 2010 passed on December 17, 2010) would originate in the rate case forecast periods. Since Taxes Payable in Working Capital is based on the average of the beginning and ending balance in the projected test period, it is the period during which tax deductions originate rather than the type of tax planning activity that determines their impact on Working Capital because Taxes Payable is not a cumulative balance. Therefore contrary to Staff's assertion, Detroit Edison does have a consistent position with respect to UTP and Bonus Depreciation as it's the period during which the deduction occurs which determines the impact on the Capital Structure and Working Capital, not the type of deduction taken (UTP or Bonus Depreciation). (Exhibit S-14)

E. Combined Operating License Application ("COLA") Cost Recovery.

Edison previously explained its Combined Operating License Application ("COLA") for construction and operation of an advanced nuclear generating plant, and its request to include COLA expenditures in its projected period working capital (Edison Initial Brief, pp 93-94).

The AG appears to have abandoned its witness Mr. Coppola's assertion that continuing to pursue the COLA is not money well spent, and his suggestion of an $8.3 million reduction in projected expenditures (10 T 1814). In any event, Mr. Coppola's position lacks merit because the purpose of obtaining a Combined Operating License ("COL") for a new nuclear unit is to acquire the option to build and operate a new unit to meet a forecasted long range need. Although

demand side assumptions have been reduced in recent years, offsetting changes on the supply side, including increased environmental pressure, may have a significant impact on the cost and useful life of Edison's aging fossil-fueled base load plants. Since regulations governing COLs have no expiration for commencing construction, and long-term supply and demand assumptions continue to change, completing the licensing for a new nuclear plant is reasonable, prudent, and in the best interest of Edison's customers (9 T 1611-12, 1660). Moreover, Mr. Coppola has never been involved in preparing a COLA and he has no sound basis to offer an opinion in this area (10 T 1908).

VII. OTHER REVENUE RELATED ISSUES.

A. Revenue Decoupling Mechanism ("RDM").

Edison previously explained its proposal that the Commission terminate the Revenue Decoupling Mechanism ("RDM") that the Commission established in Case No. U-15768, and replace it with an Energy Optimization ("EO")-only based RDM, which would achieve the function of a well-designed RDM by removing the disincentive associated with Edison implementing and operating its EO program (Edison Initial Brief, pp 94-98).[77]

Staff, NRDC, and Energy Michigan propose some form of revenue tracker with various conditions and revenue limits (Staff Initial Brief, pp 90-95; MEC/NRDC Initial Brief, pp 1, 15-23; Energy Michigan Initial Brief, pp 3-4, 11-15). NRDC's proposal appears to be consistent

[77] The modified RDM would operate so that any sales reductions produced by Edison's EO program, as determined by the third-party evaluator in Edison's EO reconciliation proceedings, would be recovered through the RDM. That is, any EO-related sales reductions, by customer class, as determined by the third-party administrator, would be multiplied by the average per kWh revenue for that particular class in order to determine the RDM surcharge revenue to be recovered from customers (8 T 1370, 1372-73, 1395-96; Exhibit A-21, Schedule M2 Revised provides a simple example showing how the modified RDM would be calculated).

Edison further proposes that the Commission terminate the existing RDM on December 31, 2011, and replace it with a modified RDM beginning January 1, 2012, since Edison's EO program is reconciled annually on a calendar-year basis. For convenience, Edison proposes that the modified RDM be reconciled concurrent with Edison's annual EO reconciliations. The RDM and EO reconciliations could also be consolidated for administrative efficiency (8 T 1373).

with Edison's proposed RDM in Case No. U-15768. If the Commission is now persuaded that an RDM that reconciles sales is appropriate, then Edison can support adoption of the RDM that it proposed in Case No. U-15768 (8 T 1379). Staff has proposed a revenue based RDM. Any total sales or total revenue based RDM should be weather normalized, but it does not appear that Staff proposes to weather normalize sales revenue for its proposed RDM. At first, Staff's proposed RDM appeared to be asymmetrical, since it includes proposed caps on the amounts that Edison may recover due to sales losses. The Commission should not approve any asymmetrical total sales or revenue based RDM because such a mechanism would penalize Edison and be counterproductive to the goal of eliminating the disincentive associated with implementing EO programs (8 T 1397-98). However, Staff's Exhibit S-13, page 6, reveals that its proposal is symmetrical.

The AG did not brief the RDM issue, but Edison notes for completeness that his witness Mr. Coppola proposed to retain the current RDM based on changes in average use per customer, with three modifications (10 T 1841).[78] Edison disagrees with the AG's proposal to retain the current RDM because Edison's current RDM does not meet the requirements of a well-designed RDM, as discussed in Edison's Initial Brief (8 T 1368-71, 1398-99). Kroger supports Mr. Coppola's first modification, asserts that the second modification "is a step in the right direction, but does not go far enough," and opposes the third modification (Kroger Initial Brief, p 12). The first and third modifications are acceptable to Edison, but the second modification should be rejected as inappropriate, administratively burdensome, and unworkable (8 T 1399-1400).

[78] The proposed modifications are: (1) that actual sales be weather normalized before the RDM calculation is performed; (2) that the RDM exclude the top 200 largest electricity users from the average use per customer calculation, and any energy usage changes experienced by these customers would apparently be determined by an outside expert with any identified EO related energy savings being recognized in the RDM; and (3) once any surcharge is established in an RDM reconciliation proceeding, the surcharge would remain in place for 12 months with no further reconciliation.

Kroger's proposal to expand the second modification by "eliminating the largest customer classes from the RDM altogether" (Kroger Initial Brief, p 12) should similarly be rejected.

ABATE does not support any RDM,[79] but proposes changes to Staff's proposed RDM if the Commission adopts it (ABATE Initial Brief, pp 18-20). The key change is that any potential recovery of lost sales be limited to the absolute level of lost sales that Edison experiences. This change should be rejected because, like any asymmetrical RDM, it would be counterproductive to the goal of eliminating the disincentive associated with implementing EO programs. In order for an RDM to accomplish this goal, it must make the utility whole for the lost sales due to EO programs (8 T 1401).[80]

B. Restoration Reconciliation Mechanism, and Line Clearance Reconciliation Mechanism.

Edison previously explained its proposal that if the Commission adopts Edison's modified Revenue Decoupling Mechanism ("RDM," as discussed above), and as long as the Commission continues to use a five-year average to determine restoration costs, then the Restoration Reconciliation Mechanism ("RRM") should be eliminated. If, however, the Commission does not approve Edison's proposed RDM, then Edison requests that the Commission retain the current RRM. Edison further proposes that, since the Commission established the Line Clearance Reconciliation Mechanism ("LCRM") in connection with the RRM, if the Commission eliminates the RRM, then the Commission should also eliminate the LCRM (Edison Initial Brief, pp 98-99).

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[79] The Commission previously rejected arguments that it lacks authority to authorize an RDM, and that the Commission should not authorize an RDM as a matter of policy. See, for example, the January 11, 2011 Opinion and Order in Case No. U-15768 and U-15751, pp 65-68. ABATE notes that it is challenging the Commission's decisions on appeal, and does not elaborate on its argument(s). Edison submits that ABATE does not properly raise an issue for decision in this case. To the extent that ABATE raises an issue, however, Edison preserves its response, and notes that it is supporting the Commission on appeal.

[80] Wal-Mart appears to conceptually agree that an EO-based RDM is appropriate but goes on to suggest numerous modifications and adjustments which the Company opposes. (Wal-Mart Initial Brief, pp 5-10)

Staff "supports Detroit Edison's proposal to phase out the aforementioned trackers," but suggests that they should be eliminated without regard to the Commission's RDM decision (Staff Initial Brief, p 90). Edison disagrees because the Commission's RDM decision is related to the additional trackers. It would be appropriate to retain the RRM if the Commission adopts an RDM different than the one Edison has proposed because the current RDM reconciles any change in use per customer due to non-normal weather, since the RDM uses actual, non-weather normalized data to calculate changes in average use per customer. Storm restoration costs are driven by the frequency and intensity of stormy weather, which is typically related to hot summer weather. Therefore, the current RDM and RRM tend to move in opposite directions when it is either warmer or colder than normal, and tend to, at least partially, off-set each other with respect to cost or revenue changes due to weather fluctuations (6 T 405; 8 T 1379, 1393-94).

MCAAA suggests that the LCRM should be retained; reasoning that it protects ratepayers by ensuring that money is spent on line clearance (MCAAA Initial Brief, pp 53-55). Edison maintains that since the Commission established the Line LCRM in connection with the RRM, if the Commission eliminates the RRM, then the Commission should also eliminate the LCRM. Edison further notes that LCRM was modeled after Consumers' forestry tracker,[81] which has now been discontinued (November 4, 2010 Order in Case No. U-16191, p 34).

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[81] The Commission adopted the trackers in Case No. U-15244, stating:

> "The Commission adopts a two-way tracker mechanism for the storm and non-storm restoration expenses. The Commission agrees with Detroit Edison that the tracker mechanism should be adopted in a manner similar to the PEM.
>
> * * *
>
> "The Commission adopts a one-way tracker for line clearance that will be structured in a manner similar to Consumers Energy Company's forestry expense tracker in Case No. U-14347, with all applicable reporting

C. Tracking Mechanisms.

Staff proposes the elimination of all reconciliation mechanisms except the RDM, reasoning that they are unnecessary, in part because a utility can self-implement rate relief six months after a rate case is filed under 2008 PA 286 (Staff Initial Brief, pp 86-87, 90).[82] On the other hand, Staff opposed self implementation of the full rate increase that Edison set forth in Mr. Brudzynski's testimony, and Staff proposes that any final rate relief in this case be delayed until January 1, 2012, which would delay final rate relief in this case to approximately 14 months after Edison filed it (Staff Initial Brief, pp 82-85). Edison disagrees with both proposals, and emphasizes that they are contradictory. Moreover, the proposed delay in rate relief would be detrimental to Edison, contrary to the normal rate-setting process, and inconsistent with 2008 PA 286 (8 T 1390-91).

Staff suggests that it would be appropriate to delay a rate increase until January 2012 because that is "towards the midpoint of Detroit Edison's projected test year" (Staff Initial Brief, p 83). To the contrary, since the projected test year is April 1, 2011 until March 31, 2012, the midpoint of that test year is approximately October 1, 2011. Thus, Staff's proposal would move rate relief away from, not towards, the midpoint of the projected test year. Moreover, Edison filed its application in this case in October of 2010, and Staff acknowledges that a "final order in this case must be issued by October 2011" (Staff Initial Brief, p 83, citing MCL 460.6a(2)). The statute's mandate of timely rate relief must be applied as written, [83] and cannot be circumvented

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requirements. (December 23, 2008 Opinion and Order in Case No. U-15244, pp 54-55).

[82] ABATE agrees, without discussing a rationale (ABATE Initial Brief, p 20).

[83] S*ee, for example, Di Benedetto v West Shore Hosp*, 461 Mich 394, 402; 605 NW2d 300 (2000) ("we presume that the Legislature intended the meaning it clearly expressed - no further judicial construction is required or permitted, and the statute must be enforced as written"); *Hanson v Mecosta Co Road Comm'rs*, 465 Mich 492, 504; 638 NW2d 326 (2002); *Lorencz v Ford Motor Co*, 439 Mich 370, 376; 483 NW2d 844 (1992); *Ambs v Kalamazoo County Road Comm*, 255 Mich App 637, 650; 662 NW2d 424 (2003) ("where the language of a statute is clear, it is not the role of

by a final order that delays that relief. Staff's proposal to delay rate relief also threatens Edison's constitutional rights. *Smith v Illinois Bell Telephone Co*, 270 US 587, 591 (1926) ("Property may be as effectively taken by long-continued and unreasonable delay in putting an end to confiscatory rates as by express affirmance of them . . .").

D. Uncollectible Expense Tracking Mechanism ("UETM").

Edison previously explained that since the level of uncollectible expense is not expected to be as volatile in the near future as it has been in the past, Edison proposes that if the Commission adopts Edison's recommended level of uncollectible expense of $72.9 million for the projected test year (as discussed in Edison's Initial Brief and above), then the Uncollectible Expense Tracking Mechanism ("UETM") should be suspended. If, however, the Commission adopts an uncollectible expense level below the level proposed by Edison, then Edison proposes that the Commission retain the UETM (Edison Initial Brief, p 100).

Staff suggests that the Commission should unconditionally discontinue the UETM, reasoning that 2008 PA 286 significantly diminished the need for trackers (Staff Initial Brief, pp 87-88).[84] Edison disagrees because the components of rate relief established on the record cannot simply be dissected from each other, and applied without regard to Edison's right to just and reasonable rates. Edison incorporates the discussion in subsection C immediately above, emphasizing that Staff's proposals are internally inconsistent and contrary to law.

E. Accounting Requests.

Edison previously explained its request that the Commission grant accounting approval to charge the income tax effect of the equity component of AFUDC to a Financial Accounting Standards 109 ("FAS 109") related regulatory asset, rather than deferred federal income tax

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the judiciary to second-guess a legislative policy choice; a court's constitutional obligation is to interpret, not rewrite, the law").

[84] ABATE agrees, without discussing a rationale (ABATE Initial Brief, p 20).

expense, on a prospective basis, consistent with FAS 109 and Case Nos. U-5281 and U-10083 (Edison Initial Brief, p 100). Staff agrees (Staff Initial Brief, p 53), and no other party appears to disagree, so Edison's request should be approved.

Edison further explained and supported its request that the Commission grant accounting authorization to record to Account 186 a Miscellaneous Deferred Debit for the accrued tax (on flow through items, i.e., federal permanent differences and state income tax reserves) and interest related to Uncertain Tax Positions ("UTPs") as of January 1, 2011, plus any additional interest and tax accrued subsequent to January 1, 2011, relating to UTPs (Edison Initial Brief, pp 101-103). The Miscellaneous Deferred Debit would be trued-up to the actual tax and interest paid upon settlement of the UTP's with the taxing authority. The Company is requesting authorization for amortization of the Miscellaneous Deferred Debit to Account 407.3 "Regulatory Debit" over 5 years based upon the actual tax and interest paid resulting from settlement (7 T 1004-1005).

Staff does not support Edison's UTP proposal, suggesting that the accounting benefit would occur for customers regardless of whether taxes are deferred (Staff Initial Brief, p 54). Staff's suggestion neglects to recognize that without tax planning, working capital taxes would be paid on a current basis rather than accumulate, and result in the need for other sources of cash that have costs (7 T 1010-11). Staff is also inaccurate in suggesting that the proposed accounting change would shift the risk of the UTPs from Edison's shareholders to its customers without benefitting the customers (Staff Initial Brief, pp 54-55). Customers benefit from the full deferred tax liability, in the capital structure at zero cost including the UTP, for many years before the UTP is settled on the Company's tax return.

This increase in the deferred tax liability is a cost free source of capital, i.e. this reduces cash required from other sources resulting in, all else being equal, a lower rate of return, as

shown in Example 2 – Cost of Capital below from the direct testimony of Company Witness Ms. Lewis, which reduces revenue requirement (7 T 1003-1004). This example shows the rate of return before and after tax planning deductions. The after tax planning column includes an increase in the deferred tax liability from tax planning deductions. As a result of the increased deferred tax liability, the rate of return has been reduced from 7.0% to 6.79% due to tax planning deductions.

Example 2 – Cost of Capital

	Before Tax Planning				After Tax Planning		
	Amounts ($000)	Cost Rate %	Weighted Cost	**Add Tax Planning**	Amounts ($000)	Cost Rate %	Weighted Cost
Long-Term Debt	$ 4,000	6.00%	2.45%	(107)	$ 3,893	6.00%	2.38%
Common Equity	$ 3,900	11.00%	4.38%	(106)	$ 3,794	11.00%	4.26%
Short-Term Debt	$ 400	4.20%	0.17%	(50)	$ 350	4.20%	0.15%
Deferred Taxes	$ 1,500	0.00%	0.00%	-	$ 1,500	0.00%	0.00%
Deferred Taxes-Tax Planning	**$ -**	0.00%	0.00%	**263** *	**$ 263**	0.00%	0.00%
Total	$ 9,800		**7.00%**	-	$ 9,800		**6.79%**

* Includes UTP of $50 million

The cumulative benefit provided to customers through reduced rates resulting from tax planning deductions taken in Year 1 is significantly greater than the potential interest that would be recovered over five years if the UTP is lost on examination (7 T 1010-12). This is illustrated in Example 2 – Revenue Requirement below from the rebuttal testimony of Ms. Lewis (7 T 1012). This example assumes the UTP created from tax planning deductions taken in Year 1 is lost on examination in Year 3. The first column (Base) shows the deferred tax liability before tax planning. The columns for Years 1 - 3 show the benefit to customers created by tax planning deductions taken in Year 1 (including the UTP component) through an incremental reduction to revenue requirement of $35 million per year. Thus, the tax planning deductions taken

originating in Year 1 generate a cumulative benefit of $105 million through the end of Year 3. The last column (UTP Lost) shows that even when the UTP component is lost on audit at the end of Year 3, a $28 million incremental annual reduction to revenue requirement in Years 4 – 8 is generated from the tax planning deductions taken in Year 1. Although the loss of the UTP results in interest of $10 million that would be recovered through amortization over 5 years, this example shows that customers maintain a substantial net benefit from tax planning deductions through a $245 million cumulative reduction to the revenue requirement for Years 1 - 8.

Example 2 – Revenue Requirement

	Before Tax Planning	**With Tax Planning and UTP**			**UTP Lost**
	Base	Year 1	Year 2	Year 3	Yrs 4- 8
Rate Base	$ 9,800	$ 9,800	$ 9,800	$ 9,800	$ 9,800
Rate of Return	7.00%	6.79%	6.79%	6.79%	6.81%
Income Required	$ 686	$ 665	$ 665	$ 665	$ 667
Amortization - Misc Deferred Debit	0	0	0	0	2
Income Required after amortization	$ 686	$ 665	$ 665	$ 665	$ 669
Revenue Conversion Factor	1.6363	1.6363	1.6363	1.6363	1.6363
Revenue Requirement	$ 1,123	$ 1,088	$ 1,088	$ 1,088	$ 1,095
Ratepayer benefit	**$ -**	**$ (35)**	**$ (35)**	**$ (35)**	**$ (28)**
Cumulative benefit with tax planning and UTP		$ (35)	$ (70)	$ (105)	**$** (255)
Amortization of Misc Deferred Debit – UTP lost		0	0	0	10
Net cumulative benefit		**$ (35)**	**$ (70)**	**$ (105)**	**$ (245)**

Assumptions:
- UTP not sustained upon settlement of the examination in Year 3, amortization of Misc Deferred Debit (over 5 years) in Years 4 - 8

If the UTP is not sustained upon examination, the interest expense paid becomes an actual cost to Detroit Edison. In such a case, the UTP is not a source of cost free capital (7 T 1004). Therefore, the Company's request for recovery of interest on the UTP is appropriate because customers have already received benefits from inclusion in the Capital Structure at zero cost.

Staff suggests that the Commission should require Edison to book employee incentive compensation plan ("EICP"), supplemental employee retirement plan ("SERP"), and executive supplemental retirement plan ("ESRP") O&M expenses below the line in Account 426.5 (Staff

Initial Brief, pp 46-48). Ms. Uzenski explained that the suggestion should be rejected because Staff's proposal assumes that the Commission will always disallow Edison's recovery of costs in these categories, which improperly disregards the potential for cost recovery (7 T 1132-33). For example, in Case No. U-15244, the Commission disallowed Edison's proposed EICP recovery, but demonstrated a belief in the value of such compensation programs and suggested that an improved EICP would merit cost recovery, by stating that it "*strongly encourages Detroit Edison to continue refining its incentive compensation program for submission in a future rate proceeding*" (December 23, 2008 Opinion and Order in Case No. U-15244, p 38). Edison has submitted just such a refined plan in this case, and incorporates the EICP discussion in its Initial Brief and above demonstrating that cost recovery is fully justified.

Staff responds that its proposal does not preclude Edison from seeking cost recovery, but instead only seeks to account for items properly (Staff Initial Brief, p 48). Staff's response misses the mark because the definition of Account 426.5 is non-operating, and it is improper to record operating expenses in a non-operating account (7 T 1132). Staff further suggests that its proposal is justified "based on the inordinate amount of time that Staff spends reviewing O&M accounts" (Staff Initial Brief, p 47). Since Edison provides information to Staff through responses to audit requests, the time it takes Staff to review potentially disallowed costs is mitigated. Thus, Staff's proposal to treat cost disallowance as a foregone conclusion should be rejected as unnecessary, as well as inconsistent with the definition of account 426.5, the Commission's encouragement of plan improvements, and the record demonstrating that cost recovery should be allowed.

F. Depreciation Rates and Intangible Plant Amortization.

The Commission issued a depreciation order for Detroit Edison on June 16, 2011 in Case No. U-16117. The Order requires that "[t]he new depreciation rates and practices approved by

this order shall take effect on the day after issuance of the final order in Case No. U-16472." (Case No. U-16117 Order dated June 16, 2011, p 16) Therefore, the ALJ in this proceeding, in order to be consistent with the Commission's June 16, 2011 Order in Case No. U-16117, need only recommend that the new depreciation rates for Edison set forth in Case No. U-16117 be implemented prospectively beginning the day after the final Order rates are issued in this proceeding. This action would be consistent with Edison's witness Mr. Stanczak's proposal:

> "I propose that if the Commission issues an order during the self implementation period [in U-16117], that the Commission wait until it issues a final order in this case to make the new depreciation rates effective for accounting purposes. I further propose that under this scenario, the Commission establish two sets of rates. One set of rates would be for the self implementation period which would reflect the old depreciation rates and another set for the period after the final order is issued in this case that would reflect the new depreciation rates. This approach will eliminate any potential over or under recovery during the self-implementation period due to a change in Edison's depreciation rates." (8 T. 1386-87)

Thus, the Commission should utilize Edison's old deprecation rates for ratemaking for the self implementation period and the new deprecation rates prospectively after the final Order in this proceeding. This insures consistent accounting and ratemaking for both periods.

Edison and Staff agree that Edison's 12.1% composite amortization rate for intangible plant should be used to calculate amortization expense included in revenue requirements in this case. (Edison Initial Brief, p 104; Staff Initial Brief, p 50). No party appears to disagree. However, to clarify, Detroit Edison is not requesting a new composite amortization rate for accounting purposes. Edison recommends the continued use of the existing amortization periods based on plant type which will maintain a composite amortization rate for intangible plant of approximately 12% (7 T 1142-43).

VIII. REVENUE DEFICIENCY, REQUESTED RATE RELIEF, AND SUGGESTED MITIGATION.

Edison previously explained that it requests approximately $443 million in jurisdictional rate relief ($444 million on a total electric basis);[85] however, to mitigate the impact of the required rate relief on customers, Edison suggested three proposals that the Commission may approve to off-set or defer, for future recovery, a portion of Edison's requested rate relief, assuming that the Commission grants certain other related relief. Edison proposed (1) rather than reflect the full cost of pension and Other Post Employment Benefits ("OPEB") expense in this case, allow Edison to recover a portion of the increased cost in future periods ($46.7 million reduction); (2) reduce Edison's Nuclear Decommissioning Surcharge ($19.5 million reduction); and (3) delay the recognition of the current increase in Electric Choice in setting base rates, assuming that the Commission retains the Choice Incentive Mechanism ("CIM") with certain modifications ($123 million reduction). These proposals would collectively result in approximately a $190 million reduction in customer rates (from $443 million to $253 million, as shown on Exhibit A-14, Schedule F2.3, column (h)) (Edison Initial Brief, pp 105-106).

Staff apparently supports Edison's Nuclear Decommissioning Surcharge proposal, stating that it "appears reasonable" (Staff Initial Brief, p 49). Staff recommends denial of Edison's pension and OPEB proposal, suggesting that "there is no expense to be deferred" in light of the update to Edison's pension and OPEB costs (Staff Initial Brief, p 35). Staff's Initial Brief does not articulate a position on Edison's Electric Choice proposal, but suggests that Edison's CIM should be discontinued (Staff Initial Brief, pp 87-89; further discussed below). The AG supports

[85] After reviewing Staff's various positions, however, Edison will recognize two changes put forth by Staff in its April 1, 2011 filing; (1) more recent update to the Company's pension and other post employment benefit costs and (2) recognition of contract renewal associated with one of Edison's wholesale for resale customers (Detroit Public Lighting Department). Based on these two adjustments, Edison supports a jurisdictional revenue deficiency of approximately $357 million (approximately $361 million on a total electric basis). See Edison Initial Brief Attachment A.

Edison's Nuclear Decommissioning Surcharge proposal, but opposes Edison's pension and OPEB, and Electric Choice proposals, contending that they are "illusory" because they would delay cost recovery for recovery in the future (AG Initial Brief, p 38). Kroger indicates essentially the same position (Kroger Initial Brief, pp 6-7). DEAR "generally supports" Edison's pension and OPEB proposal, "provided that the Commission authorization provides adequate safeguards and protections" (DEAR Initial Brief, p 2).

Edison continues to support a $19.5 million annual reduction in the Fermi 2 decommissioning surcharge related to Fermi 2 end-of-life decommissioning (from the current average of $33 million per year to approximately $13.5 million per year), which would coincide with the rate changes resulting from the Commission's final order in this case.

Edison previously indicated its diminishing support for its pension and OPEB proposal as 2011 continues,[86] and now in light of updated pension and OPEB costs, agrees with Staff that this deferral is no longer necessary.

Edison continues to support its Electric Choice proposal, but emphasizes that its proposal assumes that the Commission retains the CIM with certain modifications effective the date that Edison self-implemented a rate increase in this proceeding as discussed in Edison's Initial Brief and below, since Edison would rely on the CIM to recover the deferral.

[86] Edison's pension and OPEB deferral proposal was contingent on the Commission granting the requested accounting authority prior to January 1, 2011. The Commission did not do so. As 2011 progresses, Edison's support for the requested accounting authority has diminished, due to the need to reverse portions of pension and OPEB expense recorded in the early months of 2011, which would distort Edison's financial reporting for the impacted months, should the Commission approve the deferred accounting later in the year (8 T 1414-16).

IX. COST OF SERVICE STUDY AND TREATMENT OF EXPIRED OR EXPIRING WHOLESALE FOR RETAIL ("WRS") CONTRACTS.

A. Cost of Service Study.

Edison previously explained that, in accordance with section 11(1) of 2008 PA 186 and the Commission's December 23, 2008 Opinion and Order in Case No. U-15244, Mr. Heiser used the 50-25-25 allocation methodology to determine how MPSC jurisdictional power supply and transmission costs are spread among Edison's retail rate classes (6 T 236-37). Mr. Heiser used the FERC's preferred 12 CP allocation methodology ("FERC method"), which Staff used and the Commission accepted in Case Nos. U-15244 and U-15768 to determine the jurisdictional separation (Edison Initial Brief, pp107-108). Staff agrees with Edison's allocation methodology (Staff Initial Brief, pp 60-62). Wal-Mart supports Edison's proposed revenue allocation (Wal-Mart Initial Brief, p 2). No party appears to disagree.

B. Wholesale for Retail Sales ("WRS") Contracts.

Edison previously explained its proposed ratemaking treatment responding to the expiration of its contracts with WRS customers (Edison Initial Brief, pp 108-10).[87] No party appears to disagree.

X. RATE DESIGN AND TARIFFS.

A. Allocation of Revenue Deficiency, and Reduction of Inter-Class Rate Subsidies.

Edison previously explained its proposed rates and Rate Realignment Adjustment Surcharges/Credits, which are designed to eliminate all inter-class rate subsidies identified in the Company's cost of service by October 5, 2013, without exceeding the 2.5% percent annual

[87] Edison's WRS customers are Michigan municipal and cooperative utilities that purchase power supply from Edison under long-term contracts, for resale to Michigan retail electric customers. Edison historically has had five WRS customers: (1) Croswell Municipal Light and Power ("Croswell"); (2) Sebewaing Light and Water Department ("Sebewaing"); (3) Detroit Public Lighting Department ("PLD"); (4) Wolverine Power Supply Cooperative ("Wolverine"); and (5) Thumb Electric (6 T 248; 8 T 1379).

residential cap under 2008 PA 286 (Edison Initial Brief, pp 111-14). Kroger supports Edison's proposals as "a reasonable attempt to move rates in the direction of cost of service consistent with the requirements of 2008 PA 286" (Kroger Initial Brief, p 16).

The Hospitals suggest that the current charges for Large Customer Contracts ("LCCs") are cost justified, based on indexed rates of return ("IRORs") for the LCCs exceeding the average return (*e.g*., Hospitals Initial Brief, p 13). The suggestion is based on an unsound premise. Mr. Bloch explained that the IORs are based on as-filed cost of service studies in which current rates for all but one class were insufficient to meet costs. Further, Mr. Bloch recommended that the best indication of whether or not the LCCs are cost justified should be based on a cost of service study ("COSS") with the LCC's as a separate cost of service class. The Company's as-filed COSS in this proceeding included the primary LCCs in the D6/Other rate; and the Secondary LCCs in the D4 rate, however, in response to the Hospital's discovery request DMCDE-2.1/626, the Company provided a COSS based on Detroit Edison's as-filed study that was modified to show the secondary and primary Large Customer Contracts separately instead of including them in with the D4 and the "D6/Other" rates and to add the PLD to the "Wholesale For Resale" grouping. The result of that COSS indicates that the LCC primary group has a revenue deficiency, which is a clear indication that they are below cost-to-serve (7 T 768-69; Exhibit A-27, Schedule TAB-1).

Staff concurs with Edison's analysis, stating that "it is improper to rely on IRORs to establish a service class," and that the "results from Staff's COSS show that both the LCC secondary and primary class are below the cost to provide service" (Staff Initial Brief, pp 64-66). With respect to the Hospitals further attempt to cast doubt on Exhibit A-27 (reflected in the Hospitals Initial Brief, pp 15-20), Staff goes on to explain and illustrate that the Hospitals' position "is incorrect and should be ignored" (Staff Initial Brief, pp 66-67).

Based on their unsound suggestion about cost of service, the Hospitals request that the Commission "create a permanent LCC rate class with a rate based on LCC cost of service, or in the alternative, create a Large Health Care Rate class which includes a rate based on cost of service to large health care providers, or in a further alternative, extend the existing LCCs" (Hospitals Initial Brief, p 26).

Staff takes the position that establishing a new rate class is not warranted, and "supports the continued movement of these customers back to their respectful [sic, presumably respective] rate schedule, either D3, D4, or D6, upon the expiration of the special contracts" (Staff Initial Brief, pp 63-64). Edison agrees that a new rate class for the LCCs is not justified.

The Hospitals' alternative request that the Commission extend the existing LCCs is similarly unjustified. It is important to remember that these customers have had their rates fixed since 1996 – that is for 15 years. It is therefore not unreasonable to expect that their rates would increase (See Hospitals Initial Brief, p 2). The request also seeks an illegal result because a utility is permitted to determine its own business affairs, and the Commission lacks authority to compel a utility to enter into any particular agreement.[88] The Commission also recently found that it "cannot order a utility to negotiate a written agreement."[89] Moreover, the ordered extension of below-cost-of service contracts would violate Edison's right to a commensurate return of and on its investment in providing utility service.[90]

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[88] *Union Carbide v Public Service Comm*, 431 Mich 135, 148; 428 NW2d 322 (1988).

[89] June 3, 2010 Opinion and Order in Re Michigan Consolidated Gas Company, Case No. U-15985, p 88.

[90] See *Bluefield Waterworks Improvement Co v Public Service Commission of West Virginia*, 262 US 679, 690-694; 43 S Ct 675; 67 L Ed 1176 (1923); *Federal Power Comm v Hope Natural Gas Co*, 320 US 591, 603; 64 S Ct 281; 88 L Ed 333 (1944). See also *Permian Basin Area Rate Cases*, 390 US 747, 769-70; 88 S Ct 1344; 20 L Ed 2d 312 (1968); *FPC v Memphis Light, Gas and Water Division*, 411 US 458; 43 S Ct 1723; 36 L Ed 2d 426 (1973); *General Telephone Co v Public Service Comm*, 341 Mich 620; 67 NW2d 882 (1954); *Michigan Consolidated Gas Co v Public Service Comm*, 389 Mich 624; 209 NW2d 210 (1973).

Wal-Mart proposes that the Commission eliminate the D6 distribution energy (kWh) charge from the full-service primary D6 rate, and that its associated distribution revenue requirement should be collected through the D6 full-service distribution demand (kW) charge (Wal-Mart Initial Brief, pp 2-5). Mr. Bloch explained that the proposal is based on an inaccurate assumption regarding distribution cost allocation, and a flawed premise that does not recognize that D6 full-service distribution rates are recovering not only distribution related costs, but also costs related to the overall D6 rate subsidy. The Company's proposed D6 full-service rate design includes both energy (kWh) and demand (kW) based distribution charges that provides design flexibility allowing the Company to design rate changes to the D6 rate to achieve more uniform impacts across the three voltage levels offered under D6 as well as across the hours-use of demand range. Designing rates in this manner provides an equitable sharing of the subsidy costs contained in the D6 rate (7 T 769-70). Staff agrees with Edison (Staff Initial Brief, p 75).

ABATE asserts that the Rate D6/Other rate schedule should be modified to reflect voltage level differences (ABATE Initial Brief, pp 10-18). Staff disagrees with ABATE's proposals; however, Staff indicates that ABATE raises an issue that should be addressed, but the necessary intraclass allocation information has not been developed in this case, so Staff recommends that the Commission direct Edison to supply the appropriate information in its next rate case (Staff Initial Brief, pp 70, 73-74). Edison disagrees with Staff's recommendation that the intraclass allocation needs to be addressed in a subsequent rate case and in addition they have not defined the meaning of "appropriate information".

ABATE suggests that Edison's COSS over-allocates cost to the R10 class, and proposes a revision, in part because the COSS allegedly does not properly consider the sources (purchased versus Company owned) used to serve R10 customers (ABATE Initial Brief, pp 8-10, 12-13). The suggestion is unfounded. Mr. Bloch explained that the fact that Edison may purchase power

to lower the variable cost to serve its customers does not mean that the customers no longer have cost responsibility for the fixed capital investment that the Company has made in its generation (7 T 771-72). Staff agrees with Edison (Staff Initial Brief, p 68).

Edison previously explained that Staff's method of determining the current subsidy for each cost-of-service class based on the remaining rate class subsidies from the final order in Case No. U-15768 (Edison Initial Brief, p 114) should not be used because subsequent to that final order, there have been changes in Detroit Edison's cost to serve that significantly affect the current subsidies in certain commercial and industrial rate classes. Staff responds: "After further consideration, Staff accepts the Company's rebuttal argument and recommends that the residential subsidy be recalculated in this case. Staff, therefore, agrees with the remaining balance of $72 million as presented by the Company witness T.A. Bloch on Exhibit A-14, Schedule F2.1, Page 1 of 1" (Staff Initial Brief, p 72).

B. Choice Incentive Mechanism ("CIM").

Edison previously explained and supported its proposals to continue the CIM in order to protect itself and its customers from future variability in Electric Choice sales, and to modify the current CIM by eliminating the 90/10 sharing and 200 GWh deadband if the Commission adopts Edison's proposal to defer the portion of rate relief associated with the recent increase in Electric Choice levels (Edison Initial Brief, pp 114-18).

Staff recommends that the Commission discontinue the CIM, contending that it is no longer needed in light of 2008 PA 286, particularly that Act's 10% Electric Choice cap.[91] (Staff

[91] MCL 460.10a relevantly states:

> "(1) The Commission shall issue orders establishing the rates, terms, and conditions of service that allow all retail customers of an electric utility or provider to choose an alternative electric supplier. The orders shall do all of the following:

Initial Brief, pp 87-89). ABATE also supports eliminating the CIM (ABATE Initial Brief, p 20). Edison disagrees because it is still exposed to considerable volatility, as the Commission has recognized subsequent to Act 286's enactment (December 23, 2008 Opinion and Order in Case No. U-15244, p 87: "The Commission is persuaded that, even with the 10% cap, volatility in the choice market still exists, and the CIM should be modified and extended as proposed by Detroit Edison"). The 10% Choice cap argument was again rejected in Edison's last rate case, where the Commission continued the CIM (January 11, 2010 Opinion and Order in Case Nos. U-15768 and U-15751, p 67). The record further demonstrates that, given the potential for large and rapid changes in Electric Choice levels, the CIM mechanism will protect both the Company and customers from fluctuations in participation, which impact the Company's revenues by $30 to $40 million for each 1,000 GWhs of sales movement to or from Electric Choice (8 T 1393, 8 T 1364-65). Moreover, Staff's other proposals in this case would delay final rate relief beyond 12 months, thus being at odds with Staff's secondary argument that utilities have the ability to file annual rate cases (Staff Initial Brief, p 88).

Energy Michigan suggests that the Commission consider reconciling any changes in non-fuel revenue associated with movements to and from Electric Choice at the same time as changes in PSCR costs (Energy Michigan Initial Brief, pp 2, 9-10). The suggestion would add additional complexities to both the CIM and the PSCR reconciliations by requiring a separate calculation supporting the incremental impact on PSCR costs associated with movements to and from Electric Choice. The suggestion should be rejected because it would unduly complicate the established, workable process (8 T 1404-1405). Furthermore, as Staff persuasively explained, "the Company incurs production-related costs for resources that have served ROA customers and

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> "(a) Provide that no more than 10% of an electric utility's average weather-adjusted retail sales for the preceding calendar year may take service from an alternative electric supplier at any time."

are available to serve the ROA customers again should they return to full service" and "the market conditions that make going to choice economic also make it less likely there would be full mitigation [of the costs to Detroit Edison of Electric Choice]." (See Staff Initial Brief, pp 76-81). Fundamentally, Electric Choice customers are provided a free option on Detroit Edison's electric generation and therefore the underlying premise of Energy Michigan's proposal (to coordinate costs and purported "savings" from Electric Choice) is spurious.

C. Eliminations of, and Modifications to, Tariff Schedules.

Edison previously explained its proposals to eliminate and modify tariff schedules (Edison Initial Brief, pp 118-21).

Staff recommends that the Commission adopt Edison's rate design proposals and tariff language changes with three modifications (1) design the distribution rates for the D6, D6.1 and R3 rate classes so that the differences between Electric Choice and full service rates, by voltage level, are equal to the residential subsidy amounts for those rates; (2) maintain the D1.4 Optional Residential Service Rate (Time of Day Farm and Space Heating Rate); and (3) maintain Option II of the D5 Water Heating Service Rate (Staff Initial Brief, pp 70-73). It is not clear what is meant by Staff's proposed modification to the design of the distribution rates for the D6, D6.1 and R3 rate. The Company continues to support its method of designing the D6, D6.1 and R3 rates which achieves uniform impacts across the three voltage levels as well as across the hours-use of demand range for each rate (7 T 770). Edison does not agree with Staff's recommendations to maintain the Optional Residential Service Rate – D1.4 and Option II of the D5 Water Heating Service Rate. Rate D1.4 has been closed to new service for over 17 years and Rate D5 Option II has been closed to new service for 32 years (6 T 272). Staff's recommendation for maintaining these rates is due to the rate impact on these customers of switching to an alternative rate (11 T 2254). If these rates are allowed to continue and the

relative impact never changes will these rates continue in perpetuity? The Company believes these rates have been grandfathered long enough and should be eliminated (6 T 272-4).

Kroger suggests that the tariff provision causing the Experimental Load Aggregation Tariff ("ELAP") to expire automatically upon issuance of the final order in this case should be rescinded, and that the ELAP should continue unless expressly terminated by the Commission (Kroger Initial Brief, pp 7-8). Kroger's reliance on the November 4, 2010 Opinion and Order in Case No. U-16191, p 67, n 7, is misplaced because there the Commission found that "agreed-to changes are appropriate," but here Edison disagrees with Kroger's proposed change. Mr. Bloch further explained that the ELAP is an experimental provision that, if extended by the Commission, should continue to have a termination date until an evaluation is performed that would support making the ELAP permanent. Edison's position is that the ELAP should continue with its current termination language, which would effectively continue the ELAP until a final order in Edison's next general rate case (7 T 771). Staff agrees with Edison (Staff Initial Brief, pp 75-76).

Staff recommends that Electric Choice customers pay a 1 mill per kWh charge as a contribution to Edison's environmental compliance costs (Staff Initial Brief, pp 76-81). ABATE, Energy Michigan, and Kroger disagree (ABATE Initial Brief, pp 20-22; Energy Michigan Initial Brief, pp 2-9; Kroger Initial Brief, pp 12-14). Edison agrees with Staff's recommendation and reiterates the reality that Electric Choice and its cost-free return to service provisions provide Electric Choice customers a valuable free option to return to Detroit Edison's cost based, regulated electric generation when wholesale electric prices increase. (Detroit Edison's Retail Access Service Rider – Rider EC-2, Section E5.3)

XI. ADDITIONAL ISSUES.

A. Taft-Hartley Training Trust Fund.

UWL 223 generally supports Edison's rate increase request, and further requests that the Commission (1) provide a rate increase that is also sufficient to set aside funds for a training expense trust ("UWUA Power for America Taft-Hartley Training Trust" or other funding mechanism) to address Edison's aging workforce and the anticipated shortage of necessary workers, and (2) order Edison to submit a report regarding its anticipated training costs and hiring plan (UWL 223 Initial Brief, pp 1-17).

Edison recognizes the need for training and is committed to providing appropriate funding to maintain a highly-skilled workforce that provides safe and reliable power to its customers. Edison disagrees, however, that the UWL 223's proposed training trust is either necessary or appropriate. It is undisputed that Edison has budgeted and is seeking an appropriate amount of money for training. UWL 223 does not disagree with Edison's requested level of funding. UWL 223 suggests that it has some concern about Edison's exercise of discretion with respect to training funds, but has not cited any instance where Edison has allegedly misspent any funds, or any other tangible reason to now establish a trust. Therefore, there is no factual basis to take any action on this matter.

UWL 223 asserts that the Commission has authority to order Edison's participation in its proposed training expense trust (UWL 223 Initial Brief, pp 10-15). To the contrary, UWL 223 does not cite any specific grant of such authority to the Commission.[92] UWL 223's suggested

[92] The Commission has no common law powers, and the legal maxim *expressio unius est exclusio alterius* is the appropriate guide in construing its enabling statutes. *Taylor v Michigan Public Utilities Comm*, 217 Mich 400, 402-03; 186 NW 485 (1922).The Commission has only the limited authority that the Legislature has granted to it through clear and unmistakable statutory language. *Mason Co Civil Research Council* v *Mason Co*, 343 Mich 313, 326-27; 72 NW2d 292 (1955) *Consumers Power Co* v *Public Service Comm*, 460 Mich 148; 596 NW2d 126 (1999). A doubtful power does not exist. *Mason Co Civic Research Council v Mason Co*, 343 Mich 313, 326-27; 72 NW2d 292 (1955).

authority regarding safety and system reliability are also misplaced in light of the lack of any dispute about the level of funding or how Edison has spent the funds (as discussed above). There is no credible issue regarding safety or reliability in UWL 223's attempt to mandate Edison's participation in a training expense trust. UWL 223 essentially wants the Commission to dictate a management decision for Edison, which the Commission lacks authority to do. *See, Union Carbide v Public Service Comm*, 431 Mich 135, 148; 428 NW2d 322 (1988); *Detroit Edison Co v Public Service Comm*, 221 Mich App 370, 386-88; 562 NW2d 224 (1997).

UWL 223's position also essentially constitutes an attempt to engage in, or complain about, matters of collective bargaining, which is improper before this Commission. The Commission has no authority to become involved in, let alone dictate results for, collective bargaining between Edison and UWL 223. To the extent that UWL has any cognizable complaint about an existing labor contract (which it does not), jurisdiction would be in a United States District Court under section 301(a) of the Labor Management Relations Act ("LMRA"), 29 USC 185(a).

The LMRA plainly states that "no labor organization or employer shall be required to bargain on the establishment of any such trust fund, and the refusal to do so shall not constitute an unfair labor practice" (29 USC 186). UWL 223 acknowledges that "of course" the funding of a Taft Hartley training trust must be part of an agreement between the union and the employer (UWL 223 Initial Brief, p 6, n 3. See also, *Id* at p 1, n 1, arguing that federal labor law limits the Commission's authority over Edison). UWL 223 further states that "since it is the Union who is asking that this funding take place, the Union's agreement is obviously a foregone conclusion (UWL 223 initial Brief, p 7, continuation of n 3). In other words, UWL 223 wants the Commission to order Edison to agree to a collective bargaining matter. It is the prerogative of Edison's management to decide whether, and under what circumstances, it might agree to such a

provision in a collective bargaining contract. The Commission lacks authority to dictate a management agreement to a union contract proposal, as discussed above.

UWL 223 essentially rehashes the same training trust and report arguments that it made in Edison's last rate case. Commission rejected the training trust argument, but ordered Edison to submit a report on training (January 11, 2010 Opinion and Order in Case No. U-15768 and U-15751, p 71). Accordingly, on April 7, 2010, Edison submitted a detailed report in Case No. U-15768. The UWL 223's recommendation of an additional report in this case is therefore unnecessary and inappropriate.[93] To the extent that UWL 223 may contemplate to use such a report to further support its proposed training trust, the report would also be moot in light of federal law and the Commission's limited authority, as indicated above.[94] Moreover, there is an ongoing collaborative to address these issues, as UWL 223 acknowledges (UWL 223 Initial Brief, pp 16-17). There is no sound basis to place any additional burden on Edison.

In summary, the Commission lacks authority to dictate a management decision for Edison; UWL 223 acknowledges that its proposal that the Commission order Edison to participate in a training expense fund is a matter that must be in a collective bargaining agreement under federal law; UWL 223's suggested bases of Commission authority are inconsistent with the substance of UWL 223's proposal, which is that the Commission order Edison's management to agree to UWL 223's proposed provision for a collective bargaining agreement; and there is no sound basis in the record for that proposal. Accordingly, that proposal should be rejected. Similarly, the report that UWL 223 recommends is unnecessary and

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[93] UWL 223's suggestion that the report should address "skilled workforce needed to safely and reliably supply natural gas to its customers" (UWL 223 Initial brief, p 16) is inapplicable because Edison supplies electric services, not natural gas.

[94] An issue is moot when it is impossible for the decision maker, if it should decide in favor of the complainant, to grant any relief. *Swinehart v Secretary of State*, 27 Mich App 318, 320; 183 NW2d 397 (1970); *Plumbers and Pipefitters Local Union No 190 v Wolff*, 141 Mich App 815, 818; 369 NW2d 237 (1985) (declining to address moot issues).

inappropriate, and would ultimately be moot on relevance and jurisdictional grounds. Therefore, the Commission should not order Edison to file any such report.

B. Affiliate Transactions.

MCAAA asserts that it has concerns about transactions involving Edison and other DTE affiliates, asserts that Edison's proposed Reduced Emissions Fuel ("REF") proposal in Case No. U-16434 is an example of such a transaction, and contends that there is a basis for "ring fencing" remedies (MCAAA Initial Brief, pp 22-49, 55-58). MCAAA's discussion, although lengthy, presents no meritorious point. Much of the discussion is simply disconnected from reality because it ignores that Edison is subject to a Code of Conduct that the Commission established approximately 10 years ago in Case No. U-12134. That case continues, and has a voluminous file that recently includes the May 5, 2011 annual report that Edison filed in accordance with the Code of Conduct, and Staff's June 1, 2011 memorandum confirming that there were no Code of Conduct complaints against Edison in 2010. The Commission is undoubtedly well aware of its Code of Conduct and ongoing proceedings in Case No. U-12134, so Edison will not belabor the lack of relevance in MCAAA's discussion, other than to note that it is further illustrated by MCAAA's references to "DECo's motion" and "Act 304 costs" (MCAAA Initial Brief, pp 24, 49), where plainly there is no Edison motion here and this is not an Act 304 case.[95]

MCAAA did not improve its position with cross-examination (which MCAAA also ignores) that was apparently intended to indicate that there is some issue regarding cost allocation. Instead, Ms. Uzenski repeatedly and unequivocally testified that the Corporate Staff Group used the well-established, Commission-approved allocation methodology to allocate actual costs, with no profit margin or markup (8 T 1204, 1212-13, 1218-20). She concluded that,

---

[95] Edison does, however, move to strike those portions of MCAAA's Initial Brief that rely upon non-record evidence which are found at Section II.C. pp 41-49. Here, MCAAA discusses two studies and testimony before Congress that have not been admitted as exhibits in this proceeding. (See MCL 24.276 "Evidence in a contested case…shall be offered and made part of the record. Other factual information or evidence shall not be considered in determination of the case…")

moreover: "Our Sarbanes-Oxley controls review all of our processes, including allocations to ensure that they meet with accounting requirements and internal control standards" (8 T 1221).

Thus, there is no credible concern about affiliate transactions, and no sound basis for "ring fencing" or any other remedy to address a non-existent problem. MCAAA's position is completely lacking in merit, and should be rejected in its entirety.

XII. REQUEST FOR RELIEF

Edison respectfully requests that the Commission issue its final order:

A. Granting Edison's request for final rate relief, as further supported and explained in its Application, testimony, exhibits, its Initial Brief, and this Reply Brief (including Attachments A and B), approving rates that will recover Edison's Jurisdictional revenue deficiency of approximately $357 million (approximately $361 million on a total electric basis), based on a January 2009 through December 2009 historical test year as adjusted for projected changes through March 31, 2012;

B. Approving the implementation of Edison's requested final relief as described in the rate design parameters set forth in Edison's testimony, exhibits, its Initial Brief, and this Reply Brief;

C. Granting Edison's request to approve the PSCR base that the Commission established in its December 23, 2008 Opinion and Order in Case No. U-15244, and full urea cost recovery in the PSCR process;

D. Approving Edison's proposal to continue the Choice Incentive Mechanism ("CIM") as modified;

E. Approving Edison's proposals concerning the Revenue Decoupling Mechanism (RDM"), Uncollectible Expense True-up Mechanism ("UETM"), Restoration Reconciliation Mechanism ("RRM"), and Line Clearance Reconciliation Mechanism ("LCRM");

F. Approving Edison's proposal to reduce its nuclear decommissioning surcharge;

G. Approving Edison's proposal to recognize the impact of the expiration of various wholesale for resale contracts;

H. Approving Edison's proposal concerning depreciation expense;

I. Approving Edison's proposal to implement certain customer rate schedules and tariffs to remove certain subsidies currently paid by Edison's full-service bundled commercial and industrial customers, and allowing Edison to recover all redistributed revenue resulting from the removal of these subsidies;

J. Granting any accounting authority associated with this case not already the subject of another application filed by Edison;

K. Approving the remainder of Edison's miscellaneous proposals as set forth in Edison's Application, testimony, exhibits, its Initial Brief and this Reply Brief; and

L. Granting such other lawful relief that the Commission deems reasonable and appropriate.

Respectfully submitted,

THE DETROIT EDISON COMPANY

Dated: June 22, 2011

By: ________________________________

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The Detroit Edison Company
Computation of Total Electric Revenue Deficiency ($000)
for the Test Year Ending March 31, 2012

	(a)	(b)	(c)	(d)	(e)
Line No.	**Total Electric Items**	**MPSC Staff Initial Brief**	**Detroit Edison Adjustments**	**Detroit Edison Reply Brief**	**Detroit Edison Reply Brief Sources**
1	Net Plant	$ 9,550,225	$ 3,432	$ 9,553,657	Attachment A, Page 3 of 4
2	Working Capital	514,810	77,634	592,444	Attachment A, Page 3 of 4
3	Total Rate Base	$ 10,065,035	$ 81,066	$ 10,146,101	Line 1 + Line 2
4	Rate of Return	6.4444%	0.4202%	6.8646%	Attachment A, Page 4 of 4
5	Income Required	$ 648,631	$ 47,858	$ 696,489	Line 3 * Line 4
6	Adjusted Operating Income	549,777	(73,765)	$ 476,011	Attachment A, Page 2 of 4
7	Income Deficiency / (Sufficiency)	$ 98,855	$ 121,623	$ 220,478	Line 5 - Line 6
8	Revenue Multiplier	1.6355	1.6355	1.6355	Exh S-3, Sch C2
9	Total Electric Revenue Deficiency	**$ 161,677**	**$ 198,915**	**$ 360,592**	Line 7 * Line 8
10	Requested Jurisdictional Rate Relief			**$ 357,314**	Edison's Initial Brief, p19 fn 30

The Detroit Edison Company
Adjusted Total Electric Net Operating Income ($000)
for the Test Year Ending March 31, 2012

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Staff's Initial Brief Position**	**Detroit Edison's Adjustments**	**Detroit Edison's Brief Position**	**Source**
1	Revenues	$ 4,338,702			Exh S-3, Sch C-1
2					
3	Fuel and Purchased Power	1,420,409			Exh S-3, Sch C-1
4					
5	Gross Margin	$ 2,918,293			Line 1 - Line 3
6	Adjustments: LCC Discounts		$ (5,845)	$ 2,912,448	Staff's Initial Brief page 32
7					
8	O&M Expenses	1,386,004			Staff Initial Brief page 33
9	Adjustments:				
10	- Uncollectible Expense		14,945	14,945	11 TR 2266, Staff's Initial Brief, page 44
11	- Non-Executive Employee Incentive Compensation		23,813	23,813	11 TR 2266
12	- Long-Term Incentive and Other		13,051	13,051	11 TR 2266
13	- Active Health Care Benefits		8,110	8,110	11 TR 2266
14	- Other Benefits		5,606	5,606	Exh S-3, Sch C5.2
15	- Other Benefits (IRS limits)		1,649	1,649	Edison's Initial Brief page 84
16	- Inflation on CSG Labor		3,353	3,353	11 TR 2266
17	- Board of Director Fees - Variable Portion		1,941	1,941	11 TR 2266
18	- MGM rent		1,062	1,062	11 TR 2266
19	- Commitment fees - amortization of upfront costs		1,095	1,095	11 TR 2233
20	Total O&M Expense	1,386,004	74,625	1,460,629	Line 10 thru Line 19
21					
22	Depreciation and Amortization	558,411	32,024	590,435	Exh. S3, Sch C6 , Staff's Initial Brief p6
23					
24	Property & Other Taxes	261,084	1,256	262,340	Exh S-3, C7
25					
26	Pretax Operating Income	712,794	(113,750)	599,044	Line 6 - Line 20- Line 22 - Line 24
27					
28	Federal and Other Income Taxes	170,659		170,659	
29	Adjustments:				
30	- Aggregate Tax Effect of Other NOI Adjustments		(37,712)	(37,712)	Line 31 - Line 26
31	Total Federal and Other Income Taxes	170,659	(37,712)	132,947	Line 28 thru Line 30
32					
33	Amortization of Loss on Reacquired Debt	(3,168)		(3,168)	Exh S-3, Sch C11, L6
34	Other Income	-	1,557	1,557	Exh S-3, Sch C11, L2
35	AFUDC	10,809	716	11,525	Exh S-3, Sch C11, L1 + L7
36					
37	**Adjusted Total Electric Net Operating Income**	$ 549,777	$ (73,765)	$ 476,011	L25 - L30 + L32 +L33+ L34

The Detroit Edison Company
Total Electric Rate Base - Average Net Plant ($000)
for the Test Year Ending March 31, 2012

	(a)	(b)	(c)	(d)	(e)
Line No.	**Description**	**Staff's Initial Brief Position**	**Detroit Edison Adjustments**	**Detroit Edison's Brief Position**	**Source**
	Utility Plant in Service:				
1	Plant in Service	$ 15,196,052		$ 15,196,052	Staff's Initial Brief *
2					
3	Detroit Edison Plant In-Service Adjustments:				
4	Reliability Capital Expenditures		$22,896	22,896	Line 6 - Line 1
5					
6	Adjusted Plant in Service	$ 15,196,052	$ 22,896	$ 15,218,948	Edison's Initial Brief, Attach A, p2
7					
8	Property Held for Future Use	986	3,474	4,460	Exh S-2, Sch B2
9	Construction Work in Progress	667,484	(6,628)	660,856	Exh S-2, Sch B2
14					
15	Gross Utility Plant	$ 15,864,522	$ 19,742	$ 15,884,264	Line 6 + Line 8 + Line 9
16					
17	Deduct:				
18	Accum. Depreciation and Depletion for Plant in Service	6,464,246		6,464,246	Exh S-2, Sch B3 *
19					
20	Detroit Edison Accumulated Depreciation Reserve Adjustments:				
21	Staff's proposed reduction in depreciaton rates		16,310	16,310	Line 18 - Line 23
22					
23	Adjusted - Accum. Depreciation and Depletion for Plant in Service	$ 6,464,246	$ 16,310	$ 6,480,556	Edison's Initial Brief, Attach A, p2
24					
25	Net Capital Lease Property	33,129		33,129	Exh S-2, Sch B1.1
26	Net Nuclear Fuel Property	149,949		149,949	Exh S-2, Sch B1.1
27					
28					
29	Net Utility Plant	$ 9,583,354	$ 3,432	$ 9,586,786	Line 15 - Line 23 + Line 25 + Line 26
30					
31	Less: Capital Lease Obligations	33,129		33,129	Exh S-2, Sch B1.1
32					
33	Net Plant	$ 9,550,225	$ 3,432	$ 9,553,657	
34					
35	**Working Capital**	514,810		514,810	Exh S-2, Sch B4
36	Working Capital				
37	Adjustments:				
38	Mellon Bank - nonqualified benefit plans	0	67,700	67,700	Exh S-2, Sch B4
39	Deferred compensation		(1,694)	(1,694)	Exh S-2, Sch B4
40	Deferred gain from MGM sale	0	11,628	11,628	Exh S-2, Sch B4
41					
42	Adjusted Working Capital	$514,810	$77,634	$592,444	Line 35 thru Line 40
43					
44	**Total Electric Rate Base**	**$ 10,065,035**	**$ 81,066**	**$ 10,146,101**	

Note:
* Adjusted to reflect updated capital expenditures related to reliability (Staff Initial Brief pgs 8 and 9)

The Detroit Edison Company
Overall Rate of Return Summary ($000)
for the Test Year Ended Jmarch 31, 2012

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
Line No.	**Description**	**Staff's Initial Brief Position**	**Detroit Edison Adjustments**	**Detroit Edison's Brief Position**	**Total Capital**	**Staff's Cost Rate (1)**	**Detroit Edison Adjustments**	**Detroit Edison's Cost Rate (2)**	**Weighted Cost of Total Capital**	**Revenue Multiplier**	**Pretax Overall ROR**
1	Long-Term Debt	$ 4,216,493	$ -	$ 4,216,493	41.56%	5.5300%	0.0500%	5.5800%	2.3189%	1.008065	2.3376%
2											
3	Common Equity	4,084,743		4,084,743	40.26%	10.1500%	0.9750%	11.1250%	4.4788%	1.635501	7.3251%
4											
5	Sub-Total	$ 8,301,236	$ -	$ 8,301,236							
6											
7	Short-Term Debt	$ -		$ -	0.00%	0.7800%	0.2200%	1.0000%	0.0000%	1.008065	0.0000%
8											
9	Regulatory Liability - REP	182,976		182,976	1.80%	0.7800%	0.2200%	1.0000%	0.0180%	1.008065	0.0181%
10											
11	Net Deferred Federal Income Tax	1,602,180		1,602,180	15.79%	0.0000%		0.0000%	0.0000%		
12											
13	JDITC										
14	JDITC - Long-Term Debt	30,327	-	30,327	0.30%	5.5300%	0.0500%	5.5800%	0.0167%	1.008065	0.0168%
15	JDITC - Common Equity	29,383	-	29,383	0.29%	10.1500%	0.9750%	11.1250%	0.0322%	1.635501	0.0527%
16	Total JDITC	$ 59,710	$ -	$ 59,710							
17											
18	Total	$ 10,146,102	$ -	$ 10,146,102	100.00%				6.8646%		9.7503%

Source:
(1) Exh S-4, Sch D1, Page 1
(2) Exh A-11, Sch D1

The Detroit Edison Company
Total Electric Revenue Requirement Adjustments to Staff's Filing
for the Test Year Ending March 31, 2012
($000)

Line No.	(a) Description	(b) Source		(c) Total Electric Revenue Deficiency
1				(Pre Tax Amts)
2	**Staff's Proposed Total Electric Rate Relief for Detroit Edison**	MPSC Staff's Initial Brief page 5		**$ 161,677**
3				
4	**Adjustments to Staff's Recommended Revenue Deficiency:**			
5				
6	**Capital Structure**			
7				
8	- ROE Adjustment (to Detroit Edison's Filed Position of 11.125%)	(1)		65,072
9	- Debt cost rates Adjustment (to Detroit Edison's Filed Position)	(2)		4,099
10				
11	**Rate Base (3)**		Rate Base	
12			Changes	
13	- Net Plant - Reliability Capital expenditures	Attachment A, Page 3	3,432	385
14	- Working capital - Mellon Bank - nonqualified benefit plans	Attachment A, Page 3	67,700	7,601
15	- Working capital - Deferred compensation	Attachment A, Page 3	(1,694)	(190)
16	- Working capital - Deferred gain from MGM sale	Attachment A, Page 3	11,628	1,305
17			81,066	
18				
19	**Revenues (LCC Discounts)**	Attachment A, Page 2		5,845
20				
21	**Operations and Maintenance Expenses**			
22				
23	- Uncollectible Expense	Attachment A, Page 2		14,945
24				
25	- Non-Executive Employee Incentive Compensation	Attachment A, Page 2		23,813
26				
27	- Long-Term Incentive and Other	Attachment A, Page 2		13,051
28				
29	- Active Health Care Benefits	Attachment A, Page 2		8,110
30				
31	- Other Benefits	Attachment A, Page 2		5,606
32				
33	- Other Benefits (IRS limits)	Attachment A, Page 2		1,649
34				
35	- Inflation on CSG labor	Attachment A, Page 2		3,353
36				
37	- Board of Director Fees Adjustment	Attachment A, Page 2		1,941
38				
39	- MGM rent	Attachment A, Page 2		1,062
40				
41	- Commitment Fees	Attachment A, Page 2		1,095
42				
43	**Depreciation**	Attachment A, Page 2		32,024
44				
45	**Property & Other Taxes**	Attachment A, Page 2		1,256
46				
47	**Other Income**	Attachment A, Page 2		(1,557)
48				
49	**AFUDC**	Attachment A, Page 2		(716)
50				
51	**Federal Income Tax(Domestic Production, R&D Credit)**			6,264
52				
53	**Michigan Business Tax (Credit Limitation)**			3,365
54				
55	**Municipal Tax and Other**			(463)
56				
57	Total Adjustments to Staff's Proposed Revenue Deficiency	Line 8 through Line 55		$ 198,915
58				
59	**Detroit Edison's Requested Total Electric Rate Relief**	Line 2 + Line 57		**$ 360,592**
60				
61				
62	**Requested Jurisdictional Rate Relief**	Edison's Initial Brief, p19 fn 30		$ 357,314

(1) ROE impact: $10,065,035 (Staff's Rate Base) x .3953% x 1.6355 (revenue multiplier)
(2) Debt cost impact: $10,065,035 (Staff's Rate Base) x .0249% x 1.6355 (revenue multiplier)
(3) Rate Base Change x 6.86% (Edison's weighted cost of capital) x 1.6355 (revenue multiplier)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of THE DETROIT EDISON COMPANY for authority to increase its rates, amend its rate schedules and rules governing the the distribution and supply of electric energy, and for miscellaneous accounting authority. ____	)))))))	Case No. U-16472 (Paperless e-file)
In the Matter of the Application of THE DETROIT EDISON COMPANY for Approval to defer certain pension and post-employment benefits expense for future Amortization and Recovery. ____	))))))	Case No. U-16489 (Paperless e-file)

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss.
COUNTY OF WAYNE)

Estella R. Branson, being duly sworn, deposes and says that on the 22nd day of June, 2011, a copy of The Detroit Edison Company's Reply Brief in the above captioned matters was served upon the persons on the attached service list.

____
Estella R. Branson

Subscribed and sworn to before
me this 22nd day of June, 2011.

____
Karyn Beth Teal, Notary Public
Macomb County, Michigan
My Commission Expires: 7-21-2011
Acting in Wayne County

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