STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **THE DETROIT EDISON COMPANY** for Reconciliation of its Power Supply Cost Recovery Plan for the 12-month Period Ending December 31, 2011 _______________________________________/	Case No. **U-16434-R** (Paperless e-mail)

INITIAL BRIEF OF
MICHIGAN COMMUNITY ACTION AGENCY ASSOCIATION

The Michigan Community Action Agency Association (MCAAA) files this Initial Brief in accordance with the revised schedule set by the presiding Administrative Law Judge (ALJ). This case involves the Power Supply Cost Recovery (PSCR) Reconciliation case of the Detroit Edison Company (DECo) for the 12-month period ending December 31, 2011, undertaken pursuant to the provisions of 1982 PA 304, MCL 460.6a and 6j, *et seq* (Act 304).

I. FACTS AND BACKGROUND

This case is one of several cases involving the Reduced Emissions Fuel (REF) program that impacts the reconciliation of DECo's costs and revenues related to coal burned at DECo's coal plants to generate electricity for its customers. In all of the cases, the MCAAA has asserted that the REF production tax credits constitute a proper cost offset to DECo's cost of coal that should be recognized under Act 304, and that the diversion of these tax credit revenues to DTE's unregulated affiliates is unlawful and unreasonable. These cases have sequentially added to the record evidence concerning the REF issues, and are discussed next.

1. MPSC Case No. U-16434

In U-16434, DECo's PSCR Plan case for 2011, MCAAA presented expert evidence and briefing on this issue.

MCAAA Witness Peloquin in U-16434 (T 295-296) presented testimony regarding affiliated transactions and the need for "ring-fencing" remedies to address same, including REF transactions, as follows:

> **Q. Please briefly address the issue of ring-fencing.**
>
> A. DECO is a subsidiary of DTE Energy, which also owns Michigan Consolidated Gas Company (Mich Con), and a number of unregulated subsidiaries and affiliates. In turn, DECO and Mich Con also own subsidiaries and affiliates. (See **MCAAA Exhibit 11**, attached hereto, which consists of introductory pages of DTE Energy Company's Form 10-K). This holding company structure inherently provides the framework and incentive for potential intercorporate transactions aimed at enhancing holding company consolidated profits at the expense of the regulated utility subsidiaries. Such transactions can in turn drive up the costs and rates of the regulated utilities, as holding company profits can be derived under the guise of utility costs, in some instances for services or products that are provided to the utility that are unnecessary or that are provided at an inflated cost or mark-up given that the transactions are not subject to the discipline of arms-length completive processes.
>
> Several utility commissions around the country are now instituting regulatory approaches referred to as "ring-fencing" to protect the utility from adverse impacts arising from intercorporate affiliated transactions or subsidies. The application of this regulatory tool is more fully described in the literature 1. *1 Maryland Commission Staff, "Commission Staff Analysis of Ring-Fencing Measures for Investor-Owned Electric and Gas Utilities", February 18, 2005; Paper on behalf of NARUC Staff Subcommittee on Accounting and Finance, "Ring Fencing Mechanisms for Insulating a Utility in a Holding Company System", circa 2004; Testimony of Marc Spitzer, Commissioner, Federal Energy Regulatory Commission, Before the Committee on Energy and Natural Resources, United States Senate, May 1, 2008.*
>
> In order to ensure that DECO's base and Act 304 rates are minimized and are just and reasonable, and that DECO's costs arise from reasonable and prudent activities, policies, and practices, the Commission should direct that "ring-fencing" approaches be instituted with respect to DECO. In addition, the Commission should undertake review and audit of certain of DECO's (and DTE and Mich Con) affiliates to ensure against potentially

> abusive intercorporate transactions that may adversely impact DECO's costs and rates. The Commission's authority to undertake such audits and reviews is well grounded in the state statutes applicable to the Commission, but are now also buttressed by the provisions of federal law, including Section 1265 of the Public Utility Holding Company Act of 2005, 42 USC 1261 et seq., which is a part of the Energy Policy Act of 2005 (EPACT).
>
> The need for these enhanced regulatory approaches is highlighted by examples of DECO's intercorporate transactions or proposals as discussed later in my testimony.

Witness Peloquin also sponsored **Exhibit MCAAA-11**, comprising portions of DTE Energy Company's Form 10k for 2009, which demonstrated the vastness and interlocking nature of the DTE holding company system, including DECo and numerous DTE affiliates. Many of the DTE affiliates are unregulated, yet are engaged in the same kinds of businesses or services as DECo.

In U-16434, MCAAA Witness Peloquin testified on the REF issue in relevant part as follows (T 299-301):

> **Q. Do you oppose Detroit Edison's proposal to include the Reduced Emission Fuels program as a component of PSCR factors?**
>
> A. Yes, I do oppose Edison's REF proposal.
>
> **Q. Please state why you oppose this proposal.**
>
> A. The REF proposal, in my opinion, is not a category of expense to be included in a PSCR Plan. Edison's REF proposal is to generate excess SO_2 allowances for sales. At this time, Edison does not need to <u>purchase</u> SO_2 allowances for the consumption of coal.
>
> Additionally, Detroit Edison's REF proposal would set a number of poor ratemaking precedents. The REF proposal would endorse Edison's sale of utility coal to affiliates at Edison's book cost. The Commission historically has required the sale of utility property to be at the <u>higher</u> of the utility's cost or market prices. Given Edison's huge economics of scale, its expertise and its investments, Edison's book cost of coal is quite likely less per ton than the local market price of coal at or near St. Clair, Michigan. Another troubling precedent is Edison's purchase of Refined Coal from its subsidiaries at a price greater than their out-of-pocket cost. Note that the cap on price of the REF project is the affiliates' "revenue requirements associated with the REF." As we know, the term "revenue

> requirements" includes a component for a return on investment, otherwise known as income on profit. Thus, the Fuel Companies will be selling refined coal to Detroit Edison at a profit. Also, DTE Energy Services is going to make a return (income) on its "coal refinement technology." Historically, the Commission has required utility purchases from its affiliates to be at the lower of cost or market.
>
> Edison's REF proposal would set a precedent of this Commission's approval of a utility purchasing a product from an affiliate at cost plus a profit. This is poor public policy.
>
> Detroit Edison's REF proposal additionally includes an interesting conundrum. DTE wants the affiliates to earn an unspecified "revenue requirement." The Fuel Companies apparently already have equipment installed in Belle River and St. Clair coal hauling systems and they will own coal inventories. Is the Commission going to set the "revenue requirements" for these non-utility affiliates of Detroit Edison; namely, Belle River Fuel Company, St. Clair Fuel Company, and DTE Energy Services?
>
> Additionally, Edison's REF proposal simply does not meet the spirit of the original adjustment clauses. First, the adjustment clauses were needed because there generally were many years between general rate cases. Second, the expenses covered were subject to large changes in price and their cost was a very significant component of the utility's cost of service. And, third, the utility had little ability to control these expenses. The prime example is the cost of fuel for electric generation. None of these three premises fit Edison's REF proposal. Currently, the old practice of long periods between general rate cases is now ancient history. Second, Edison's 2011 REF proposal's gross cost is insignificant to Detroit Edison. Third, DECo's affiliates have a high degree of control over the cost of the REF project.
>
> DECo's REF proposal is no gift horse. Rather, the REF proposal is a Trojan horse that needs to be kept out of the ratemaking arena.

The Commission’s December 6, 2011 Order in U-16434 found in relevant part (pp 8 and 11) as follows:

> . . . .The Commission agrees with the Staff, the Attorney General, MCAAA, and the ALJ that the request for inclusion of the REF Project costs in its 2011-2015 PSCR plan cases is premature. Even Detroit Edison indicates that the proposal is somewhat preliminary. The evidence offered simply does not demonstrate the reasonableness and prudence of the amounts to be paid for services rendered by the affiliates, nor does it demonstrate exactly to what extent the REF adder will actually reduce SO_2 and No_x emissions. This decision has no impact on the requested factor,

> and the Commission is not rejecting the entire PSCR plan. However, the Commission finds that, in order to authorize these costs in future plan cases, it will require additional evidence, as is discussed in more detail in the next section. (Order, p 8).
>
> * * *
>
> As with the REF Project as a whole, the Commission finds that this request is premature and not well fleshed-out. While the Commission finds that the five-year forecast complies with MCL 460.6j, it also finds that, on the basis of the evidence presented in this case only, the Commission would be unlikely to permit recovery of the requested costs in 2015. Detroit Edison has given the Commission very little idea of whether, and how much, the sorbents will actually reduce mercury emissions. This does not preclude allowing future recovery. However, the Commission will require more and better information on the efficacy of available methods for achieving mercury emissions reductions, as well as a demonstration showing that the REF Project is a reasonable and prudent way of achieving the maximum reductions for the minimum cost, from both a technological and business point of view. The REF Project must also be shown to comply with the Code of Conduct. The Commission recognizes that Rule 1503 presents a formidable challenge for the company, and commends Detroit Edison for diligently pursuing strategies now, for achieving compliance with Rule 1503 in 2015. Detroit Edison will need to return to the Commission with a much more detailed presentation on the costs, benefits, and efficacy of the fuel treatment program, as well as the costs and benefits of other potential mercury emissions reduction processes, if any exist. (Order, p 11).

2. MPSC Case No. U-16047-R.

In U-16047-R, involving the PSCR Reconciliation for the year 2010, MCAAA again presented extensive evidence and briefing on these issues.

MCAAA Witness Peloquin (T-345-346) in this case testified regarding DECo's scant reference to the REF issue in its 2010 Plan case, U-16047, and also the status of the REF project as discussed in DTE/DECo's SEC 10K report for 2010:

> **Q. Did Detroit Edison seek approval of its REF Project (Reduced Emissions Fuel) in its 2010 PSCR Plan case?**
>
> A. No. Review of DECo's filed case reveals no specific reference to the REF Project. DECo's Witness Mr. Hoffman's prefiled testimony at pp 8 and 9 did address "advanced cleaner energy fuels".

Q. Were additional costs associated with the use of renewable or advanced cleaner energy fuel considered in your forecast?

A. Detroit Edison is evaluating co-firing renewable and advanced cleaner energy fuels in its existing conventional power plants with the intent to maximize the amount of renewable energy credits (RECs) and advanced cleaner energy credits (ACECs) generated without increasing the overall cost of fuel recovered through the Power Supply Cost Recovery (PSCR) mechanism while at the same time not exceeding the projected marginal cost of a REC or ACEC. Each co-firing opportunity will be affected by the location of the fuel source, environmental impacts, plan operation economics and scale. However, the Company is in the exploratory phase of reviewing these opportunities. If new information emerges that requires a change in assumptions, the Company will reflect those changed assumptions in future PSCR plans or plan amendments.

DECo's Witness Mr. Wojtowicz prefiled testimony at p 23 states:

> "The forecast shown on Exhibit A-19 (APW-7) indicates that there is no purchase need for SO2 emission allowances in 2010."

The 2010 PSCR Plan case concluded with a Commission approval Settlement Agreement. I could find no reference to the REF Project in the Settlement Agreement.

Q. Did DTE Energy operate Reduced Emission Fuel facilities during 2010?

A. Yes, it did.

I have attached Exhibit MCAAA-1, excerpts from DTE's Form 10K for 2010. The following information is found in this 10K.

"In late 2009, we began operating reduced emissions fuel facilities located at Detroit Edison owned power plants. (p 43)

and

"We own and operate five facilities that process raw coal into reduced emission fuel. . ." (p 15)

Page 16 reveals that one million dollars of "Production Tax Credits" for "Reduced Emission Fuel" was allocated to DTE Energy during 2010.

Exhibit MCAAA-1, DTE/DECo's SEC 10K Report for 2010, page 15, describing DTE's unregulated Power and Industrial Projects subsidiary, provides more complete information concerning the REF project, as follows:

> *Reduced Emission Fuel:* We deliver reduced emission fuel to utilities with coal-fired electric generation power plants. We own and operate five facilities that process raw coal into reduced emission fuel resulting in reductions in Nitrogen Oxide (NO) and Mercury (Hg) emissions. We began generating production tax credits from these facilities beginning in 2009 which will continue through 2019 upon achieving certain criteria, including entering into transactions with unrelated equity partners or third-party customers for the reduced emission fuel. We continue to optimize these facilities by seeking investors for facilities operating at Detroit Edison sites, and intend to relocate other facilities to alternative sites which may provide increased production and emission reduction opportunities in 2011 and future years. In January 2011, the Company entered into an agreement to sell a membership interest in one of these reduced emission fuel facilities that is located at a Detroit Edison site.
>
> *Coal Services:* The business provides coal transportation and related services including fuel to our customers with significant energy requirements which include electric utilities, merchant power producers, integrated steel mills and large industrial companies. We specialize in minimizing fuel costs and maximizing reliability of supply for those energy-intensive customers. We own and operate a coal transloading terminal which provides storage and blending for our customers. We also engage in coal marketing which includes the marketing and trading of physical coal and coal financial instruments, and forward contracts for the purchase and sale of emission allowances.

Exhibit MCAAA-1, DTE/DECo's SEC 10K Report for 2010, page 24, also states in part:

> *Our ability to utilize production tax credits may be limited.* To reduce U.S. dependence on imported oil, the Internal Revenue Code provides production tax credits as an incentive for taxpayers to produce fuels and electricity from alternative sources. We have generated production tax credits from coke production, landfill gas recovery, biomass fired electric generation, reduced emission fuel, steel industry fuel and gas production operations. All production tax credits taken after 2008 are subject to audit by the Internal Revenue Service (IRS). If our production tax credits were disallowed in whole or in part as a result of an IRS audit, there could be additional tax liabilities owed for previously recognized tax credits that could significantly impact our earnings and cash flows.

MCAAA Witness Peloquin testified in this case concerning the more complete discussion of the REF project included within DECo's 2011 PSCR Plan Case U-16434, including in part the following (T 349-350):

> **Q. Do you oppose Detroit Edison's proposal to include the Reduced Emission Fuels program as a component of PSCR factors?**
>
> A. Yes, I do oppose Edison's REF proposal.
>
> **Q. Please state why you oppose this proposal.**
>
> A. The REF proposal, in my opinion, is not a category of expense to be included in a PSCR Plan. Edison's REF proposal is to generate excess SO_2 allowances for sales. At this time, Edison does not need to <u>purchase</u> SO_2 allowances for the consumption of coal.
>
> Additionally, Detroit Edison's REF proposal would set a number of poor ratemaking precedents. The REF proposal would endorse Edison's sale of utility coal to affiliates at Edison's book cost. The Commission historically has required the sale of utility property to be at the <u>higher</u> of the utility's cost or market prices. Given Edison's huge economics of scale, its expertise and its investments, Edison's book cost of coal is quite likely less per ton than the local market price of coal at or near St. Clair, Michigan. Another troubling precedent is Edison's purchase of Refined Coal from its subsidiaries at a price greater than their out-of-pocket cost. Note that the cap on price of the REF project is the affiliates' "revenue requirements associated with the REF." As we know, the term "revenue requirements" includes a component for a return on investment, otherwise known as income or profit. Thus, the Fuel Companies will be selling refined coal to Detroit Edison at a profit. Also, DTE Energy Services is going to make a return (income) on its "coal refinement technology." Historically, the Commission has required utility purchases from its affiliates to be at the lower of cost or market.
>
> Edison's REF proposal would set a precedent of this Commission's approval of a utility purchasing a product from an affiliate at cost plus a profit. This is poor public policy.
>
> Detroit Edison's REF proposal additionally includes an interesting conundrum. DTE wants the affiliates to earn an unspecified "revenue requirement." The Fuel Companies apparently already have equipment installed in Belle River and St. Clair coal hauling systems and they will own coal

> inventories. Is the Commission going to set the "revenue requirements" for these non-utility affiliates of Detroit Edison; namely, Belle River Fuel Company, St. Clair Fuel Company, and DTE Energy Services?
>
> Additionally, Edison's REF proposal simply does not meet the spirit of the original adjustment clauses. First, the adjustment clauses were needed because there generally were many years between general rate cases. Second, the expenses covered were subject to large changes in price and their cost was a very significant component of the utility's cost of service. And, third, the utility had little ability to control these expenses. The prime example is the cost of fuel for electric generation. None of these three premises fit Edison's REF proposal. Currently, the old practice of long periods between general rate cases is now ancient history. Second, Edison's 2011 REF proposal's gross cost is insignificant to Detroit Edison. Third, DECo's affiliates have a high degree of control over the cost of the REF project.

MCAAA Witness Peloquin (T-356-357) also presented ratemaking remedies applicable to DECo's REF project, as follows:

> **Q. Do you have a recommendation regarding DTE's REF Projects in this 2010 PSCR Reconciliation Case?**
>
> A. Yes. All Reduced Emissions Fuel costs included in DECo fuel inventories and fuel expenses should be disallowed. While DECo's REF Project expenses may well violate a number of Act 304 prohibitions, the fact that this change in accounting and ratemaking treatment for fuel expense was not previously approved in the 2010 PSCR Plan Case requires disapproval.
>
> **Q. Are there methods that could be utilized to gain approval of costs for reduced emissions fuels?**
>
> A. Yes. One possible example is the accounting and ratemaking approvals of Edison's Midwest Energy Resources Company subsidiary (MERC). The MERC facility is included in DECo's ratebase and its capital costs are excluded from DECo's fuel inventory costs. For additional information regarding MERC ratemaking, refer to the Commission orders in Case Nos. U-5041 and U-5108.
>
> **Q. Were you involved in Case U-5108?**
>
> A. Yes. I recollect testifying in support of ratebasing the MERC facility in Case U-5108.

The following interchange in U-16047-R occurred during cross-examination of DECo Witness Lapplander (T 321-322):

> Q. (By Mr. Keskey) Exhibit MCAAA-1 includes certain pages of the 10K report of DTE and Detroit Edison for 2010, and on page 15 of that exhibit, it states in part: "We began generating production tax credits from these facilities beginning in 2009 which will continue through 2019 upon achieving certain criteria, including entering into transactions with unrelated equity partners or third-party customers for the reduced emission fuel."
>
> Does that pretty much comport with your understanding of the arrangement?
>
> A. Yes.
>
> Q. And is there a requirement that the unrelated equity partners have a majority interest in the facilities?
>
> A. That's my understanding.
>
> Q. And have you already entered into a transaction with one of the equity partners?
>
> A. The affiliate did with St. Clair in January 2011.

DECo has also claimed in case U-16047-R that the REF transactions resulted in no cost impacts for purposes of this reconciliation case for 2010. However, it is unclear as to how this claim can be made. The record showed that the REF project was implemented in 2009 or 2010. DTE's/DECo's SEC 10K Report for 2010, included in part in Exhibit MCAAA-1, at page 43, states:

> In late 2009, we began operating reduced emission fuel facilities located at Detroit Edison owned coal-fired power plants. The facilities reduce Nitrogen Oxide (NO) and Mercury (Hg) emissions and qualify for production tax credits when the fuel is sold to an unrelated party through 2019. We continue to optimize these facilities by seeking investors for facilities operating at Detroit Edison sites and intend to relocate other facilities to alternative sites which may provide increased production and emission reduction opportunities in 2011 and future years. In January 2011, the Company entered into an agreement to sell a membership interest in one of these reduced emission fuel facilities that is located at a Detroit Edison site.

The record in U-16047-R also established that significant REF costs were included in that case for 2010. DECo provided more information regarding REF coal transactions in a discovery response to Question No. MCAAA/DE26, included within Exhibit MCAAA-7, as follows:

> **Question:** Is the company obtaining or using any coal supplied by an affiliate (as defined in the instructions above). If so, detail the amounts and costs for this PSCR year, and provide analysis that such coal is cheaper or of better quality than that available from non-affiliated parties during totally commensurate timeframes.
>
> **Answer:** In 2010, the Company used refined coal and resold coal supplied by the Belle River Fuels Company (BRFC) and St. Clair Fuels Company (SCFC).
>
> In 2010, the Company used 4,688,674 tons of refined and resold coal from BRFC, at a cost of $126,096,248.
>
> In 2010, the Company used 430,844 tons of refined and resold coal from SCFC, at a cost of $10,764,324.
>
> As described in the response to Question MCAAA/DE 21:
>
> The BRFC and SCFC operated Reduced Emission Fuels (REF) facilities at the Belle River Power Plant and St. Clair Power Plant. Both BRFC and SCFC were operating these facilities to test their operational effectiveness. As a result, a substantial portion of the western coal (LSW) used at both Belle River and St. Clair Power Plants was sold to the BRFC and SCFC and purchased back by Detroit Edison. No additional fuel expense was incurred in 2010 compared to what would have occurred if the REF facilities were not operated.
>
> As the coal was purchased from the BRFC and SCFC at the same cost that Detroit Edison incurred to purchase the coal initially, the costs can be reasonably assumed to be cheaper than coal purchased from and delivered by other entities. An explanation of the cost effectiveness of the Company's fuel procurement methods was discussed in the response to Question MCAAA/DE 16.

In its discovery response to Question No. MCAAA/DE30 (included in Exhibit MCAAA-9), DECo stated in part:

> The BRFC and SCFC operated Reduced Emission Fuels (REF) facilities at the Belle River Power Plant and St. Clair Power Plant. Prior to either affiliate's facilities being partially sold to other investors in order to

monetize future tax credits, both affiliates were operating these facilities to demonstrate their operational effectiveness.

As a result, a substantial portion of the western coal (LSW) used at both Belle River and St. Clair Power Plants was sold to the BRFC and SCFC at booked inventory cost, and purchased back (whether refined or not) at the same booked inventory cost. No additional fuel expense was incurred in 2010 compared to what would have occurred if the REF facilities were not operated.

CECo Witness James D. Good also testified regarding the REF project. During cross examination (T 239-240), the following interchange occurred:

Q (By Mr. Keskey): Now, let me turn, Mr. Good, to Exhibit MCA-7, and particularly to the Response DE26. And there you mention in your answer that the Company in 2010 used refined coal and resold coal supplied by the Belle River Fuels Company and the St. Clair Fuels Company. Are those the only two fuels companies that are engaged in the reduced emission fuels transactions?

A In 2010, yes.

Q Are there some additional ones in 2011?

A Yes, there's the Monroe Fuels Company.

Q Any others?

A No.

Q Now, I believe it's your 10K report with the SEC for 2010 on page 15 indicates that the Company owns and operates five facilities that process raw coal into reduced- emission fuel. And are there, are those five facilities all located at specific plants?

A Yes. Three of them are at St. Clair and two are at Belle River.

Q So there are five facilities, but they're serving two plants?

A Yes. For purposes of clarification, each piece of equipment is titled to a facility, each piece of equipment, of the REF equipment, each product line, as it were, so there's three parallel treatment lines. For example, for the St. Clair, it's listed as three facilities.

DECo Witness Gary Lapplander also presented rebuttal testimony and Exhibits A-24 and A-25 concerning the REF issues. His Exhibit A-24 presents and overview of the REF project, while his A-25 is described as a Refined Coal Added Impacts Calculation Worksheet (T 281).

The Witness (T 281-283) testified:

Q. **When did the REF facilities begin operation at Detroit Edison plants?**

A. The Belle River Fuels Company (BRFC) and St. Clair Fuels Company (SCFC), subsidiaries of DTE Energy Services, placed in service their respective facilities in December 2009. These facilities produced REF during 2010 to allow for testing at both the Detroit Edison Belle River and St. Clair Plants. The Belle River facility has two production lines and the St. Clair facility has three production lines.

Q. **Did BRFC generate any tax credits through the operation of the BRFC facilities through 2010?**

A. Yes. To qualify for a tax credit under section 45 of the IRS Tax Code a facility had to be placed into service prior to January 1, 2010. In addition, the Refined Coal must be sold to an unrelated party. The tax credits belong to the owner of the REF facility. The BRFC had the opportunity to generate a tax credit because their facility was placed into service in December 2009 and could sell Refined Coal to an unrelated third party, the Michigan Public Power Agency (MPPA).

Q. **Did SCFC generate any tax credits through the operation of the SCFC facilities through 2010?**

A. No.

Q. **How much REF did the Belle River and St. Clair Power Plants consume during 2010?**

A. The Belle River Plant consumed 4.6 million tons of coal in 2010 and approximately 1.2 million tons or 26% was REF. The St. Clair Plant consumed approximately 400,000 tons of REF or 11% of its total consumption of 3.8 million tons of coal. The REF purchased by Detroit Edison in 2010 was priced at the original weighted average inventory cost at which Detroit Edison sold the coal to the BRFC and SCFC, i.e., the price did not include a Refined Coal Adder and there was no increased cost whatsoever to Detroit Edison associated with the REF project.

Q. **Did either BRFC or SCFC sell an interest in any of their production lines at Belle River or St. Clair Power Plants?**

A. Yes. In January of 2011 a membership interest was sold in the entity owning one of the REF production lines at the St. Clair Power Plant. This arrangement allows the SCFC to begin generating tax credits through the production of Refined Coal sold to Detroit Edison.

On April 25, 2013, the MPSC issued an Order in U-16047-R that essentially sidestepped the need to reconcile the net costs of DECo's coal (after reduction for the REF production tax credits) for each year of the 10-year tax credit program, including 2010. The order disregarded evidence, including DTEs/DECo's 10-K SEC Reports, indicating the realization of tax credits in 2010. The Order (pp 7-8) stated in relevant part:

> Not only was there no change in accounting and ratemaking related to REF during 2010, but there was also no REF-related cost increase. *See*, 2 Tr 264. MCAAA provided no evidence disputing these facts. On this basis alone, the Commission finds that it must reject MCAAA's exceptions respecting the REF program. The Commission further notes that MCAAA ignores several essential facts, most notably that no party proved that any tax credit was realized for 2010 by Detroit Edison, its parent, or any of its affiliates, associated with the REF project. No evidence regarding tax credits was presented for the Commission's consideration, and thus there is nothing for the Commission to "net." Finally, MCAAA fails to address the fact that Detroit Edison did not incur the costs associated with building the REF facilities, and thus could not accrue the tax credit benefits that flow therefrom.

The Order improperly shifts the burden of proof to MCAAA to establish the amount of the REF tax credits or revenues obtained in 2010 (by DTE and its affiliates) which information DECo refused to disclose in discovery.

The Order also states that "Detroit Edison did not incur the costs associated with building the REF facilities, and thus could not accrue the tax credit benefits that flow therefrom." This extraneous finding is not based upon any factual evidence or discussion in this case comparing the costs of the REF facilities (of which only 3 of the 7 were useable at DECo's plants, whereas the rest were developed to market to third parties), in comparison to the vast size of the tax credit benefits obtained by DTE and it affiliates. The Order fails to recognize that the major costs of the DECo supply chain and the coal inventories are supported by DECo's ratepayers, and that the tax credit revenues are based upon a per-ton-of-coal basis ($6.33 per ton), not with respect to the cost of the REF facilities, and that in any event the capital and other costs of the REF facilities have already been otherwise provided for and covered by other aspects of the REF proposal.

3. MPSC Case No. U-16892.

In U-16892, DECo's PSCR Plan case for 2012, MCAAA again presented extensive evidence and briefing on the REF issues. MCAAA's testimony in U-16892 on the REF issues included the direct testimony of CPA William A. Peloquin, with revisions and cross-examination, appears at TR 641-698. The witness' exhibits entered into the record includes Exhibit MCAAA-4, Exhibit MCAAA-5 (updated), Exhibit MCAAA-6 (Revised), Exhibit MCAAA-7, and Exhibit MCAAA-8. Witness Peloquin's testified (T 666-676) regarding DECo's Refined Emission Fuel (REF) projects, as follows:

> **Q. What is the purpose of your testimony in this case?**
>
> A. I am addressing the issue of the refined coal production tax credits and the REF projects.
>
> My testimony deals with the action by DTE Energy, DECo's unregulated parent holding company, and by DECo, in transferring to third party fuel companies large portions of DECo's coal inventories and transportation functions in a manner that diverts offsets to Edison's fuel costs (such as tax benefits) to the detriment of DECo's Act 304 costs and rates.
>
> **Q. Detroit Edison alleges that the REF program is not relevant to the PSCR process because it does not increase expenses. Do you agree that it is irrelevant?**
>
> A. No. Detroit Edison adds substantial expenses to the PSCR process for environmental compliance. Mr. Wojtowicz's pre-filed testimony includes:
>
> a. \$1.7 million to purchase No× ozone emission allowances at page 23, and;
>
> b) \$1.95 million to purchase NO_x annual emission allowances at page 23, and;

c. Acid Rain Program $S0_2$ emission allowances with an expense of $1.47 million at page 24, and;

d. Urea expense of $4.6 million at page 29, and;

e. beginning in 2015, $11.1 million for Mercury Sorbent at page 20 and Exhibit A-20.

Edison charges the ratepayers for its environment compliance through the PSCR process for emission allowances and sorbents, and through base rates for capital investments and O&M applicable to electrostatic precipitators, scrubbers (FGD), activated carbon injection (ACI) systems, and fabric filters (FF). However, when the federal government subsidizes the REF program, Edison refuses to flow the generous production tax credits through to its ratepayers. If the ratepayers are charged for the expenses of environmental compliance they should also receive the collateral benefits when they are available.

Q. Are there other examples of items that are included in the PSCR/GCR process even though they do not increase expenses?

A. Yes. Ms. Wojtowicz included a PSCR benefit of $14.7 million for the projected sale of CSAPR SO_2 emission allowances at page 24 of her prefiled testimony.

Gas utilities routinely flow pipeline refunds through their GCR clauses even though they do not increase expenses.

Q. What other reasons are the REF projects relevant in this case?

A. The REF projects are directly related to the cost of fuel that the Commission is reviewing to set PSCR rates. The cost of fuel includes both cost increases and cost decreases or offsets (such as fuel related tax events) to determine and reconcile net fuel costs.

Q. Please describe the Reduced Emission's Fuel (REF) project(s) that has been instituted by DTE/DECO?

A. DTE placed (5) five REF units in-service in 2009 at the Belle River/St. Clair complex. DTE recorded about $1 million of refined coal productions tax credits in 2009 per its SEC Form 10K. These five REF units were owned by the newly formed St. Clair Fuel Company and the Belle River Fuel Company (SCFC and BRFC). Detroit Edison and the Fuel Companies are all subsidiaries of DTE Energy, therefore they are financial affiliates. DTE placed another (4) four REF units in-service during 2011. Edison claims that the St. Clair Fuel Company was placed in-service

January 2011 and the Monroe Fuel Company was placed in-service November 2011.

DECo transferred large portions of its coal inventories, plus its coal transportation functions, to the fuel companies starting approximately in 2009, as detailed in DECo's SEC 10-K Annual reports for the years, 2009, 2010, and 2011 (attached as Exhibit MCAAA-4). Edison has transferred its low sulphur western (LSW) coal for St. Clair and Monroe to the St. Clair and Monroe Fuel Companies, FOB MERC. Edison has also transferred its St. Clair and Monroe eastern coal FOB the mine sites. Therefore, all of this coal is now apparently non-jurisdictional. Edison has ripped asunder its fuel supply in part to shield the REF tax credits benefits from the ratepayers.

Q. Has the Commission approved any of DECo's transactions related to the REF projects?

A. No. DECo made scant reference to the REF Projects in its 2009 and 2010 Plan cases. In DECo's PSCR Plan case for 2011, MPSC Case No. U-16434, DECo also made brief mention of the REF projects.

In that case, I testified extensively regarding the lack of information and documentation requesting the REF projects. The ALJ and Commission rejected DECo's REF proposal.

Q. Has DECo provided more information in this case to explain and justify its REF proposals?

A. No. DECo's case provides precious little information to justify MPSC approval of the REF projects. DECo did provide some incomplete information regarding the REF proposals in its PSCR reconciliation case for 2010, MPSC Case No. U-16047-R, but none of the information justified DECo's REF projects, or the resulting impact on PSCR costs (including the diversion of net cost reductions from receipt of tax credit benefits to minimize the cost of fuel).

Q. Why do you challenge DECo's REF projects in this case?

A. DECo and DTE Energy proceeded to undertake these major transactions without any prior approval of the Commission. Also, the transactions have adversely impacted PSCR costs and rates because they have diverted PSCR cost reductions or savings that would otherwise go to reduce PSCR costs and rates, to the benefit of the Fuel Companies, which are owned in whole or part by DTE affiliates or have been sold to third parties.

Q. Please describe your concerns regarding the REF projects in addition to the PSCR cost and rate impacts.

A. DECo has effectively transferred major elements and components of its coal and coal transportation functions from the regulated utility to unregulated third party entities. In doing so, DECo appears to take the position that the books and records of the fuel companies are diverted from MPSC regulating oversight and control, and audit and review (and similarly being made out of reach by other parties intervening in DECo rate and Act 304 cases). This constitutes a major divestment of major components of DECo as a utility to evade regulation and to diminish MPSC's ratemaking and accounting authority.

Q. What are your recommendations to address DECo's REF projects?

A. It is my recommendation that the ALJ and Commission order the following:

1. The Commission should order that all of the Fuel Companies should be required to disclose all of their books and records. The Commission should jurisdictionize the Fuel Companies and they should be "rolled into" the ratemaking process. This is similar to the jurisdictionization and "rollin" of DECo's Midwest Energy Resources Company (MERC), at DECo's request, in Case Nos. U-5041 and U-5108.

2. The MPSC should expressly require that all cost increase impacts, as well as all cost decreases or benefits (including tax credits) that otherwise would reduce base rates or PSCR rates be fully recognized in rates. In this proceeding the Commission should reduce the PSCR costs by $30 million for the Monroe Fuels Company coal discount and by $9 million for the St. Clair Fuels Company coal discount. (See Exhibits MCAAA - 7 & 8).

3. That the Commission order DECo to report any and all aspects of the REF projects, including any updates or changes thereto, on an annual basis.

Q. Was there a benefit to Detroit Edison to jurisdictionalize MERC?

A. Yes. MERC was initially constructed to transship Decker coal. The Decker coal contract included several step increases in the annual tonnages with a final large step increase applicable to the completion of a new powerplant (Belle River). Because of the gradual increases in Decker coal tonnages, the MERC facility initially had substantial excess capacity. By including MERC in DECo's rate base, Edison avoided the probability of serious under-recoveries.

Q. Do you believe that the MPSC has the authority to institute your recommendations?

A. Yes. The Commission has jurisdiction to engage in the regulation of accounting matters, including requiring reports, undertaking audits, and obtaining discovery to complement its ratemaking authority. The Commission also has authority to review affiliated intercorporate transactions, as confirmed by a considerable MPSC and judicial authority. The MPSC also has enhanced authority to review the books and records of affiliates pursuant to the 2005 Amendments to the Public Utility Holding Company Act (PUHCA).

Q. Do you have an estimate of the 2012 amount of DTE's REF production tax credits?

A. Yes, in excess of $120.5 million. Tax credits are after tax amounts since they are not taxable.

Q. Please describe your Exhibit MCAAA-5.

A. Exhibit MCAAA-5 (Updated) illustrates the REF production tax credits generated in 2012. The $14,083,125 2012 tax credit for St. Clair is utilized for my subsequent exhibit.

The IRS should publish the 2012 REF Tax Credit rate in April 2012. I updated this exhibit with the 2012 data when it became available.

Q. Please explain your Exhibit MCAAA-6 (Revised).

A. Exhibit MCAAA-6 (Revised) develops the 2012 revenue deficiency/sufficiency of the St. Clair Fuels Company, on a traditional ratemaking basis. The compilation of this exhibit begins at page 3 of 6, with the data provided by DECo. Note that DECo's calculation included an overall rate of return of 6.586%. This is the overall rate of return found at page 41 of the Commission's October 20, 2011 Order in Case Nos. U-16472/U-16489. This order included a 1.6355 revenue multiplier at page 92, which rounds to a 1.636 "Revenue Conversion Factor" found in the DECo response. A 1.6355 revenue multiplier implicitly includes a composite income tax rate of 38.856%.

Page 2 of 6 of Exhibit MCAAA-6 (Revised) develops the 2012 Adjusted Net Operating Income for St. Clair Fuels Company. The Production Tax Credits on line 1 are transcribed from Exhibit MCAAA-5 (Updated). The amounts on lines 2 though 8 are transcribed from the DECo data. The amounts for lines 2 through 7 are converted to after-tax values. I excluded the amount for "Interest on Working Capital Loan". Edison already included a recovery of its overall rate of return on its rate base, therefore a second recovery of capital costs is inappropriate. I then added amounts for depreciation expense and proforma interest tax savings. This results in a $11.5 million Adjusted Net Operating Income (ANOI) for 2012.

The compilation continues on page 1. Note that the amounts for lines 1 through 6 are transcribed from the Edison data. The insertation of the ANOI from page 2 results in a income sufficiency of $8 million and a revenue sufficiency of $13.2 million.

Q. What is the relevance of the 8.40 $/ton Revenue Sufficiency found at the bottom of page 1?

A. St. Clair Fuels Company could transfer a $8.40 per ton coal discount to the PSCR customers for 2012 and still earn a full 6.586% overall rate of return on its ratebase.

Q. If St. Clair Fuels had a $13.2 million revenue sufficiency for 2012, what rate of return did it earn?

A. St. Clair Fuels earned a 22.090% overall rate of return and a 48.733% return on equity (ROE). These returns are computed on pages 5 and 6 of this exhibit.

Q. You also include amounts for the revenue sufficiency "Excluding Coal Inventory". What is the purpose of this column?

A. The "Coal in Inventory" amounts are still included in the calculation of Edison's base rates. Therefore, including this category in the fuel company's rate base is a double recovery. Excluding the "Coal in Inventory" results in a 10.39 $/ton of excess revenue equivalence. While I have not utilized the $10.39 per ton amount, only in an attempt to be conservative for this Plan case.

Q. Please explain your Exhibit MCAAA-7.

A. Detroit Edison includes a small Monroe REF Coal Discount in its 2012 Plan case. However, it is not adequate. Based upon my analysis of St. Clair's 2011 revenue sufficiency of $8.40 to $10.39 per ton, I believe that a $4.00 $/ton 2012 coal discount for Monroe would be appropriate. A 4.00 $/ton coal discount for Monroe would yield a PSCR cost reduction of $30 million, or $24.8 million in addition to DECo's proposed cost discount.

Q, Why do you believe that a 4 $/ton coal discount is appropriate.

A. The REF facilities and their process is not likely to change between 2011 and 2012, nor between St. Clair and Monroe.

St. Clair included a full year, or almost a full year, of operation in 2011. Therefore, it is a fair standard to set the coal discount. Additionally, by utilizing a 4 $/ton discount rate, variances in volumes are automatically adjusted for. The 4 $/ton rate is conservative for a least two reasons. The

2012 refined coal production tax credit will be increased for inflation. And, as the Fuel Company's gain experience, their costs per ton should decrease.

I would also note that Plan cases are always projections. Absolute precision is not necessary since actual amounts will be known and utilized in the subsequent Reconciliation Cases.

Q. Why did you use 2011 data for the 2012 Monroe coal discount?

A. Edison refused to furnish the requested data.

Q. Please explain your Exhibit MCAAA-8?

A. This exhibit is very similar to Exhibit MCAAA-7. I used the 4.00 $/ton coal discount rate for St. Clairs 2012 REF tonnage, which I believe is appropriate.

I also excluded DECo's proposed St. Clair Coal Adder. St. Clair Fuels generated a 29% ROE in 2011. Their request to recover an addition $416,000 for emission allowances is an unreasonable request. St. Clair can readily afford to provide a 4 $/ton coal discount without an coal adder.

Q. Why did you use 2011 data for the 2012 St. Clair coal discount?

A. Edison refused to furnish the requested data.

Q. DTE's 2011 SEC Form 10K indicates that the 99% of St. Clair Fuels Company was sold to a tax partner. Does this affect your St. Clair coal discount?

A. Not necessarily. The Form 10K indicates that there was only a minor down payment with installment payments as the production tax credits are earned. Therefore, the tax sale may have little or no effect on the coal discount.

Q. Did you request information about these tax sales?

A. Yes, and Edison refused to furnish the information.

Q. Please summarize other reasons why the Commission should implement adjustments related to the REF projects and the Fuel Companies?

A. First, DECO and its parent, DTE, have undertaken, without Commission approval, a major divestment of its coal supply chain and coal inventories, and have attempted to divert revenues or tax credit benefits away from

> DECO and its regulated rates, and for the benefit of DTE or its unregulated subsidiaries and third parties. The solution to this problem is to role in all of the Fuel Companies into the ratemaking process and to make appropriate offsetting rate adjustments to protect ratepayers. The Commission should assert full ratemaking, accounting, and audit authority over all of the fuel companies, much the same as the Commission did with respect to MERC in Case U-5041 and U- 5108.
>
> Second, DECO has effected in part a double recovery on working capital associated with the coal inventories sold to the fuel companies, and has not fully aligned the working capital impacts in this case with corresponding adjustments in its most recent rate case, U-16472.
>
> Third, the creation of the fuel companies has served to transfer major aspects of DECo's utility functions, including its coal inventories, coal transportation, and coal handling and processing to unregulated entities, and has thus attempted to diminish the Commission's regulatory jurisdiction relative to ratemaking and accounting under Act 304 and other statutes. It has also attempted to undermine the contested case process under these statutes by refusing to provide information and discovery answers relative to important financial details and ratemaking impacts arising from these transactions and relating to the fuel companies.
>
> Fourth, DECo and DTE have sought to divert important tax credit benefits and other revenues which should be full offsets to Act 304 rates, and has also sought to monetize its transactions by selling its interests in the fuel companies without recognizing these gains as an offset to DECO's costs and rates.
>
> Fifth, the fuel companies have not assumed any risk. DTE pursued the creation of the fuel companies by using DECO's resources and services, and by making DECO the captive participant or customer in the transactions.
>
> Sixth, Act 304 appears to prohibit the kind of transactions that have been undertaken with respect to the fuel companies. See Sections 6j(13)(a), (d), (e), and (g) of Act 304, MCL 18 460.6j (a), (d), (e), and (g).

During cross-examination (T 691-692) Witness Peloquin acknowledged that his corrections to his testimony included an error on page 13 (pre-filed, line 9, T-671). The correct figures, as noted on Exhibit MCAAA-5 (updated) is $62,684,475, not the prior stated figure of $120.5 million (see quote on page ____ *supra*).

4. MPSC Case No. U-16434-R

In this case, U-16434-R, the PSCR reconciliation for 2011, wherein the hearings were completed on March 8, 2013, MCAAA again presented extensive evidence and briefing regarding the REF coal issues.

MCAAA presented the direct testimony (T 793-812) and Exhibits (Exhibits MCAAA 1 through 7) of its Witness Geoffrey Crandall, and also the surrebuttal testimony (T 890-901, with portions stricken) and Exhibit MCAAA-34 of its Witness CPA William A. Peloquin. MCAAA Witness Crandall discussed the REF projects in part at T 795-796:

> **Q. What is the purpose of your testimony in this case?**
>
> A. I address issues related to the proposed ratemaking treatment of the Applicants Reduced Emission Fuels (REF) projects. Various affiliated transactions have occurred during the Act 304 – CY 2011 reconciliation period between DTE Energy (DTE) affiliates, Special Fuel Companies, and the Detroit Edison Company (DECo) and I specifically address the implications of those transactions on Act 304 customer's fuel costs.
>
> **Q. Please describe the 2011 REF projects based on the information you have access to.**
>
> A. According to DTE Exhibit A-10, the production and sale of refined coal from a qualified facility is eligible for a tax credit under Section 45 of the Internal Revenue Code. DTE also indicates that refined coal must be sold to an unrelated person in order to qualify for a federal tax credit. The tax credit is reportedly available for a 10-year period beginning on the date the facility is placed into service. In Exhibit A-10, DTE indicated that the tax credit value for refined coal in 2011 was equal to $6.33 per ton of refined coal. DTE also indicated in Exhibit A-10 that in 2011 it had seven production lines in either the test phase or operational. These were located at the Monroe Power Plant (2), at the Belle River Power Plant (2) and at the St Clair Power Plant (3).
>
> **Q. Did DECO request advance approval for the REF projects and to divert revenues or credits as an offset to coal costs under Act 304?**
>
> A. No. It is my understanding that DECo did not seek authorization from the MPSC to utilize the credits in conjunction with the 2009 or 2010 Act 304 planning cases. It is also my understanding that the Administrative Law Judge and the Commission rejected DECo's REF proposal in conjunction with the U-16434 Plan case.

MCAAA Witness Crandall (T 796-797) describes the lack of “benefits” of the REF transactions:

> **Q. Are DECO’s suggested justifications or “benefits” for the REF-affiliated transactions sufficient for MPSC approval of a diversion of the REF generated revenues as a reduction to coal costs in this and other Act 304 cases?**
>
> A. No. For example, DECo suggests that increases in emissions control costs will be saved by allowing the diversion of REF revenues to offset coal costs. However, future emission control costs are speculative, and in any event have always been included as Act 304 costs. Also, the claimed “savings” in emission allowances or other costs are also speculative and are subject to change. By definition, a future savings in future “expenses” is outside the 2011 period and is not a CY 2011 expense.

MCAAA Witness Crandall (T 797-802) also described the impact of REF projects upon PSCR costs and rates:

> **Q. Please describe the impact of the REF projects upon the PSCR costs and rate factors of DECO.**
>
> A. REF transactions divert significant tax credit revenues from use and transformation of the DECo 304 purchased coal (which by all rights should otherwise be an offset to coal costs) to unregulated affiliates of DTE, the unregulated parent company of DECo. This business arrangement is contrary to provisions of Act 304 and is fatally flawed since it is oblivious to the crucial, ratepayer-supported operational and financial resources that provide the foundation and means for DECo’s coal acquisition and transportation activities. Ratepayer support was the principal reason that DECo has in the past and now operates a significant coal acquisition and transportation operation that serves the customers in the State of Michigan.
>
> **Q. How is Act 304 relevant to the proposed REF activity that DECO has included in this application?**
>
> A. This is the 2011 reconciliation case which is required under Act 304, MCL 6a and 6j *et seq.* Act 304, in its Plan and Reconciliation process, provide for a comprehensive review of fuel related contracts and costs, and places the duty on the utility to minimize costs. Section 6j(3) requires the utility to file…“a complete power supply cost recovery plan”… which “shall describe all major contracts and power supply arrangements entered into by the utility for providing power supply during the specified 12-month period”. Section 6j(3) also requires the utility to provide “an explanation

of the actions taken by the utility to minimize the cost of fuel to the utility”.

Section 6j(4) provides for the 5-year forecast that … “shall include a description of all relevant major contracts and power supply arrangements entered into or contemplated by the utility, and such other information as the Commission may require”.

Section 6j(6) requires among other duties that “the Commission shall evaluate the reasonableness and prudence of the decisions underlying the power supply cost recovery plan”… including “whether the utility has taken all appropriate actions to minimize the cost of fuel; and other relevant factors”.

> Section 6j(12) *et seq* provides for the PSCR reconciliation prices. Sections 6j(13)(a), (d), (e), and (g), state in part:
>
> . . . (13) In its order in a power supply cost reconciliation, the commission shall:
>
> (a) Disallow cost increases resulting from changes in accounting or rate-making expense treatment not previously approved by the commission.
>
> * * * *
>
> . . . (d) Disallow transportation costs attributable to capital investments to develop a utility’s capability to transport fuel or relocate fuel at the utility’s facilities and disallow unloading and handling expenses incurred after receipt of fuel by the utility.
>
> (e) Disallow the cost of fuel purchased from an affiliated company to the extent that such fuel is more costly than fuel of requisite quality available at or about the same time from other suppliers with whom it would be comparably cost beneficial to deal.
>
> * * * *
>
> (g) Disallow additional costs resulting from unreasonably or imprudently renegotiated fuel contracts.

With respect to these provisions, DECo did not apply for its REF transactions, including related accounting or ratemaking expense treatment, in advance. DECo has not revealed the transportation (capital) costs, and unloading and handling expenses incurred after receipt of the fuel, that it is incurring through its arrangements and transactions with the affiliated fuel companies. DECo has not carried its burden to demonstrate it meets the affiliate purchasing requirements set forth in sub-paragraph (e) above. Moreover, the REF arrangements and transactions appear to result in additional costs (i.e. failure to recognize net coal costs after REF tax credit revenue offsets) which in essence comprises "unreasonably or imprudently renegotiate fuel contracts".

> Section 6j(14) and (15) of Act 304 states in part:
>
> "(14) in its order in a power supply cost reconciliation, the commission shall require a utility to refund to customers or credit to customers' bills any <u>net</u> <u>amount</u> determined to have been recovered over the period covered in excess of the amounts determined to have been actually expensed by the utility for power supply, and to have been incurred through reasonable and prudent actions not precluded by the commission order in the power supply and cost review. (emphasis added)
>
> * * * *
>
> "(15) In its order in a power supply cost reconciliation, the commission shall authorize a utility to recover from customers any <u>net amount</u> by which the amount determined to have been recovered over the period covered was less than the amount determined to have been actually expensed by the utility for power supply, and to have been incurred through reasonable and prudent actions not precluded by the commission order in the power supply and cost review. For excess costs incurred through management actions contrary to the commission's power supply and cost review order, the commission shall authorize a utility to recover costs incurred for power supply in the reconciliation period in excess of the amount recovered over the period only if the utility demonstrates by clear and convincing evidence that the excess expenses were beyond the ability of the utility to control through reasonable and prudent actions. For excess costs incurred through management actions consistent with the commission's power supply and cost review order, the commission shall authorize a utility to recover costs incurred for power supply in the reconciliation period in excess of the amount recovered over the period only if the utility demonstrates that the level of such expenses resulted form reasonable and prudent management actions" … (emphasis added).

Act 304 envisions a reconciliation of <u>net amounts</u> (i.e. increases and decreases or offsets to costs) and makes cost incurrences subject to a standard requiring "reasonable and prudent actions". The complicated affiliated REF arrangements establish a construct whereby incurred costs of coal and control of emissions remain fully in rates, while substantial cost reductions in the form of substantial revenues arising from tax credits associated with coal handling and processing are diverted (and not recognized), all for the benefit of affiliates of DTE (which also wholly owns and controls the DECo). This arrangement does not minimize coal costs and does not involve reasonable and prudent actions by the utility. This result is not the kind that would be expected if the utility and the DTE affiliates were independent and were dealing at arms-length (where at least a major sharing of the revenue benefits would be expected, with resulting direct coal cost reductions to DECo).

The Act requires DECo to demonstrate that its actions in procuring fuel was reasonable, prudent and that it took actions to minimize the cost of fuel to the utility and ultimately the Act 304 customers. The operation of the proposed REF project does not satisfy the requirements and mandates set forward in Act 304 because DECo is not proposing to operate the REF so that it can "minimize the cost of fuel" needed to provide electricity to its Act 304 customers. The proposed REF project does not comport with the requirements contained in Act 304 and would therefore not be in the public interest and should not be authorized and allowed by the Commission as is proposed .

Q. Should there be additional scrutiny of the REF transitions because they were created by the holding parent company and its affiliates, and thus involved an affiliated transaction subject to incentives for inter-corporate abuses?

A. Yes. I have been advised by counsel that both state and federal precedent establishes that enhanced scrutiny and skepticism of affiliates transactions should be applied to these transactions because of their affiliated nature.

Q. In your opinion, do the REF projects and transactions comprise the kind of transactions and functions that should be subject to review and remedy in an Act 304 reconciliation case?

A. Yes. The Commission's regulation and reconciliation of the diverted REF tax credit revenues as a means to reduce Act 304 related costs goes to the core of Act 304 fuel cost regulation. The attempted REF-diverted revenues should be recognized as integral in the calculation of coal fuel costs and should be recognized as a reduction to fuel costs.

Q. Has DECo shown in any way that the benefits to the DTE holding company system achieved through the diversion of REF tax credit revenues (which should otherwise be an offset to DECo's coal costs) is

commensurate or reasonable compared to the costs or impacts on Act 304 ratepayers?

A. No. As noted, there is no demonstration of benefits accruing to ratepayers from DECo's proposal as compared to the benefits given up by the ratepayers.

Q. Is the review of REF issues and ratemaking remedies limited to costs recovery or cost increases exclusively or does it also include recognition of benefits such as "negative costs" (credits or refunds) for ratemaking purposes in this and other Act 304 cases.

A. Act 304 is not a limited to rate freezes or upward adjustments. The purpose of frequent review and fuel clause adjustments as Act 304 is to adopt rates based upon costs of fuel, purchased power, and other related costs. Act 304 provides for increases <u>and decreases</u> in such costs.

MCAAA Witness Crandall (T 802-811) then explained various ratemaking remedies to address the REF transactions:

Q. You have explained that the clean coal tax credits should flow back to the ratepayers. How would you recommend the clean coal tax credits for 2011 be returned to the ratepayers?

A. This docket is a reconciliation of the 2011 PSCR fuel and purchased power costs. The most straightforward way to return the clean coal tax credits to the ratepayers is to disallow coal costs by the amount of the tax credit and adjust the PSCR rate accordingly. This would reduce the amount of coal expense recoverable through the rates to what the ratepayer cost would have been had ratepayers received the clean coal tax credit.

Q. How large was the tax credit received for REF in 2011?

A. I have estimated the tax credit received for 2011 REF coal burned to be $18,413,000.

According to the Company in response to MCAAA/DE-47, DECo purchased a total of 2,908,986 tons of REF coal in 2011 (See Exhibit MCAAA-2). Mr. Lapplander identified the 2011 tax credit as $6.33 per ton of REF coal during cross examination in Docket

U-16047-R, Tr. 316, line 15. I confirmed that value was reported in the April 26, 2011 IRS release of the 2011 Section 45 Production Tax credits. Based on this information, the tax credit received for the REF coal burned by DECO in 2011 was $18,413,000.

Q. Is this the amount of tax credit actually received by DTE in 2011 for REF coal?

A. Probably not. DTE engaged in a complicated set of transactions to "monetize" the tax credit through tax partners and to prevent it from flowing to ratepayers. As a result of that process, it is probable that DTE received a far greater amount of money in 2011 for the REF clean coal tax credits.

Q. Please explain.

A. DTE structured the REF Fuels Companies as seven separate limited liability corporations under DTE REF Holdings LLC. DTE REF Holdings LLC is a subsidiary of DTE Energy Services, Inc., which s a subsidiary of DTE Energy Resources, Inc., which in turn is a company held by DTE Energy Company. This structure was described in response to MCAAA/DE-11. Please see Exhibit MCAAA-3.

To monetize the tax credit, DTE sold membership shares of its REF facilities at St. Clair and Monroe. In January 2011, it sold 99% of its St. Clair REF LLCs and in November 2011 it sold 99% of its Monroe REF LLCs to one or more non-affiliated tax partners. DTE still retains 100% ownership of the Belle River REF LLCs and 1% ownership of the St. Clair and Monroe REF LLCs.

Q. Who bought the membership shares of DTE' REF LLCs?

A. DTE refused to provide this information in the discovery process up to this time.

Q. How much money did DTE receive in compensation for the membership shares it sold?

A. DTE refused to provide that information, but we can make an estimate that DTE may have received $300 - $400 million in monetized tax credits in 2011.

The principle of the membership sale is to allow DTE to gain the REF clean coal tax credits. The deal would probably involve DTE selling memberships in the REF LLCs to tax partners, and allow the tax partners to collect the tax credits from the IRS. Thus, the cost of the membership to the tax partner should approach, but be less than the expected value of the tax credits received over the ten year period for which the credits are available. They would have to be less than the expected value of the tax credits to give the tax partner an opportunity to earn on their investment and also to compensate them for the risk that the tax credits could be less than expected.

According to information filed by DECo in response to MEC/DE-3.2 in Docket U-16892, the amount of REF coal DECo expects to purchase rises from 2,908,986 tons in 2011 to 9,681,000 tons in 2012, up to 14,299,000 tons in 2016. See Exhibit MCAAA-4.

Q. Are all of the REF coal purchases described above relevant to the monetized tax credit received in 2011 by DTE?

A. No. DTE's membership sales involved only the St. Clair and Monroe Fuel Companies in 2011. Thus, any monetization of tax credits that may be associated with Belle River or other future Fuel Companies was not included in the 2011 tax partner transactions.

Q. Why is it appropriate to consider tax credits that the tax partners will receive in 2012 and beyond when estimating the compensation that DTE received in 2011?

A. It is appropriate and necessary to consider the tax credits that the tax partners will receive in 2012 through 2020 when estimating the compensation received by DTE in 2011 for the membership sale because the tax credits are received over a 10-year period. In 2011, DTE exchanged the annual tax credit for the 10-year period for the St Clair and Monroe REF for a membership sale price.

We can estimate the membership sale price received by DTE by multiplying the expected tons of REF fuel sold to DECo by the tax credit in each year through 2020. Taking the present value of that stream of payments establishes the current value of the expected stream. Tax partners would demand the opportunity to earn on their investment in the membership, thus the compensation received by DTE would approach, but be less than the present value of the tax credits. Since the annual tax credits are a product of the REF tons and the tax credit per ton, the actual tax credits may be higher or lower than expected, primarily because the volumes of REF coal consumed may be higher or lower than expected.

Q. Please explain Exhibit MCAAA-5.

A. Exhibit MCAAA-5 is the basis of my estimate that DTE may have received $300 to $400 million in 2011 to monetize the tax credits for REF from St Clair and Monroe. The first column shows the tons of REF coal DECo expects to purchase. The second column shows the actual and assumed IRS tax credits per ton of REF coal. The third column is the annual tax credit (product of the previous two columns), and the fourth is the present value of each annual tax credit. The present value of the expected REF tax credits for the St Clair and Monroe REF companies is $502 million.

Giving the tax partners an opportunity to make a profit and to compensate them for the risk that the REF volumes are less than expected, I adjusted the present value down from $500 million to $300 to $400 million. I believe this to be a reasonable estimate of what DTE may have received in 2011 as a monetization of the REF clean coal tax credit. This money should be flowed back to ratepayers.

Q. Are there other ways that the REF tax credits could be returned to ratepayers?

A. Yes. The Fuel Companies could discount the cost of the processed clean coal, similar to what is proposed for the Monroe Fuel Company in the current PSCR Plan case, Docket U-16892. The discount could reflect the overall effect of the REF tax credit and overall costs and revenues associated with the processing.

Q. What would be the appropriate discount to the cost of coal purchased from the fuel companies?

A. Details were not provided by the Company, but Michigan Community Action Agency Association Witness Peloquin in the current PSCR Plan case suggested a discount of $4.00 per ton of processed coal in his direct testimony, Docket U-16892, MCAAA-7, page 1.

Mr. Lapplander also gave credence to the $4.00 value in his cross examination in Docket U-16047-R, Tr. 316, line 15. Mr. Lapplander indicated that roughly $2.00 of the $6.33 per ton tax credit goes to the fixed and variable operating cost of the facility, leaving approximately $4.00 per ton available for refund to the ratepayers.

Q. How would this $4.00 per ton discount be implemented?

A. In the current reconciliation case for 2011, the $4.00 per ton discount would be applied to each ton of REF coal sold to DECo in 2011. The resulting amount (2,908,986 tons times $4.00 per ton) would result in an adjustment of $11,636,000. In my opinion, this is the minimum amount by which fuel costs should be adjusted in 2011.

If the Commission uses this method, future repurchases of clean coal from the fuel companies should be discounted by $4.00 per ton as they are invoiced.

Q. Mr. Lapplander on page GEL-9, lines 12 – 20, testifies that DECO sells coal to the Fuels Companies at its fully allocated or book cost rather than market prices, and argues that any adjustments to the sale price to reflect higher market pricing would only serve to increase the resale price to DECO. Do you agree?

A. No. Failing to charge the Fuels Companies the higher of fully allocated cost or market price may adversely affect ratepayers to the benefit of the Fuels Companies and DTE.

Q. Please explain.

A. Mr. Lapplander's argument that the price at which DECO sells coal to the Fuels Companies doesn't matter fails to consider the impact of sales of REF to non-affiliated entities. If a Fuels Company sells cleaned coal to a party other than DECo, they may generate a profit on the sale which will be retained by the Fuels Company (and DTE) rather than returned to the ratepayers.

Consider the following example whereby DECo purchases coal at less than market prices due to its large volume purchases and transportation systems in place. DECo purchases coal at $35 per ton, but the market price for smaller purchases in the same general location is $40 per ton. If DECo sells coal to the Fuels Company at either $35 or $40, and the Fuels Company processes it and sells it back at the same price plus its adder (reflecting environmental value added to the coal through the processing), Mr. Lapplander is correct that the net cost to ratepayers will be the same whether DECo charges the fully allocated cost or the market price, *for the clean coal repurchased by DECO for its use* (independent of the cost reduction for tax credit revenues discussed earlier).

Now consider the same example, except that the coal DECo sells to the Fuels Company is processed and sold to a non-affiliated entity. If DECo sells at the fully allocated cost of $35 per ton, and the Fuels Company processes it and sells it to a third party at market prices of $40 per ton (plus the adder reflecting environmental value added), then the Fuels Company makes a $5 per ton profit on coal sold to the third party. This profit should inure to the ratepayers, but it will instead remain undetected in the hands of the Fuels Company and DTE. DECo and its affiliates have not provided information regarding details of transactions related to the Fuels Company and surely would object to providing information regarding the off-system sales of clean coal.

Finally, there is also a possibility that the Fuels Company could buy the coal at below market prices and sell it at below market prices, effectively artificially becoming a more competitive supplier rather than keeping all of the profits. This would enhance their sales volumes, but the lower cost would in effect be made possible only because of the existence of and past investments by ratepayers. In effect, ratepayers would involuntarily be supporting below market deals to third parties without compensation for ratepayers' role in developing and paying for the large scale utility coal procurement that can result in below market costs.

Q. Under DECO's approach of charging a below market price for coal sold to the Fuels Companies, ratepayers may be adversely affected by paying higher PSCR rates than they would if profits from off-system sales offset PSCR coal costs. How can this problem be resolved?

A. It would be resolved by DECo following the Code of Conduct, which requires DECo to sell to its affiliates at the higher of fully allocated cost or market price. If coal was procured by DECo at below market prices, charging market prices for coal sold to its Fuels Companies affiliates would result in profits that would offset PSCR coal costs, i.e., the PSCR rates would reflect the offsets to the fuel costs through normal record-keeping rather than having to make adjustments.

The Commission should note that Mr. Lapplander indicated that DECo is selling coal to its affiliates at their fully allocated cost even though it is less than market price. This practice is in violation of the Code of

Conduct which requires DECo to make sales to affiliates at the higher of fully allocated cost or market price.

The Commission should also note that the Company did not suggest that charging the higher market price was burdensome or difficult. In fact, the Company appears to be indifferent to which method is used based on their erroneous view that either method ends up costing ratepayers the same.

I recommend that the Commission require DECo to charge the higher of fully allocated costs or market prices for its transactions with affiliates, as required under the Code of Conduct.

Q. Should the Commission adjust the fuel costs in the current reconciliation case in order for the ratepayers to benefit from off system coal sales?

A. Yes, this adjustment should be made if clean coal sales were made to non-related parties in 2011. The Company has not provided information to corroborate whether the Fuels Company's made coal sales to non-related parties.

The Fuels Companies have made clean coal sales to non-related parties in the past. In 2010, Belle River Fuels Company sold REF processed coal to Michigan Public Power Authority (MPPA).

The Fuels Companies could have made sales of REF processed coal in 2011. According to discovery response to MCAAA/DE-3 (Exhibit MCAAA-6), DECo sold 4,250,000 tons of coal to the Belle River Fuels Company, much more coal than the 2,908,986 tons of REF processed coal DECo bought back from all the Fuels Companies in 2011. It is not clear to what extent the excess coal sold to the Fuels Companies in 2011 was processed and sold to unrelated third parties or simply sold to unrelated third parties without processing. In either case, the sale of coal purchased from DECo at fully allocated costs and resold to a third party at market prices would generate a profit that should flow to the ratepayers.

The Fuels Companies may be planning to make REF coal sales to unrelated third parties in the future. In response to MEC/DE-17a, the Company provided an excerpt from DTE Energy Company's 8-K filing of October 9, 2012. Please see Exhibit MCAAA-7. Page 3 of the attachment to the response summarizes the REF development update. Under the 2012 Status, DTE indicates that they are trying to relocate four [coal REF processing] units, and specifically regarding units 3 and 4, that the Company is "In discussions with several potential host utilities." It appears that they are considering host utilities other than DECo. The 8-K filing from June 15, 2012, indicated that the Company was in discussion with five potential host utilities. From the 8-K filings, I conclude that the Company is seeking to sell REF coal to unrelated third parties, perhaps as early as 2012.

MCAAA Witness Crandall (T 812) concluded his direct testimony with the following recommendations:

Q. In conclusion, what are your recommendations that the Commission should adopt in this case?

A. I recommend the following:

a. The Commission find that DECo's use of the REF in 2011 has disadvantaged Act 304 ratepayers and has resulted in higher fuel costs than would other wise be the case.

b. The Commission require a fuel cost adjustment for the 2011 PSCR reconciliation case in the amount of either $18.4 million or $11.6 million based on annual credits, or $300 - $400 million based on ten year life of the tax credits, as is more fully described in this testimony.

c. The Commission find that DECo is in violation of the Code of Conduct and that the Commission direct DECo to use the higher of the market price or fully allocated costs when selling coal to its affiliates.

d. The Commission order in all Act 304 cases require DECo to file complete information regarding its REF arrangements and transactions, including the amount of REF tax credit revenues obtained, and such further information required by the Commission.

MCAAA Witness Peloquin's surrebuttal testimony (T 896-900) addressed the redacted portion of pages 618 - 619 of DECo's Exhibit A-30, which was later produced in unredacted form:

Q. A paragraph of the Monroe Refined Coal Supply Agreement, found at pages 618-619 of Exhibit A-30 was redacted. Have you reviewed Section 9.4 of the Monroe Refined Coal Supply Agreement?

A. Yes, I have. I compared the Monroe Section 9.4 with the St. Clair and Belle River contracts' Section 9.4. This comparison is shown on Exhibit MCAAA-34. The left hand column of this Exhibit is Section 9.4 transcribed from the St. Clair and Belle River Refined Coal Supply Agreements, Exhibit A-30 pp 375-76. The right hand column is transcribed from the unredacted Monroe Refined Coal Supply Agreement found at pp 1-2 of Exhibit A-30 Supplemental. The Monroe Refund Coal Supply Agreement deleted the previous paragraph 9.4(a) as found in the earlier St. Clair contract. This was the paragraph that required the Fuels Companies to reimburse Detroit Edison for additional O&M expense caused by the use of the refined coal.

* * *

Q. **Do you support Detroit Edison's unilateral decision to reduce the Monroe REF Discount to reimburse Edison for REF-related O&M expense for its powerplants?**

A. No.

Q. **Please explain your opposition to this DECo proposal for REF related powerplant O&M expense reimbursement via the PSCR clause.**

A. First, O&M expense is recovered in base rates. It is not a component of recoverable power supply expense. Second, the dollar amounts requested are not supported by competent testimony and/or exhibit(s).

Q. **Are there other portions of Section 9.4 that should be addressed?**

A. Yes. Section 9.4(c) of the Monroe Agreement. In the event that REF results in the Monroe fly-ash being designated a "hazardous material," then paragraph (c) requires the Monroe Fuels Company to partially reimburse DECo for its hazardous material disposal cost. However, Monroe Fuels is only required to pay the cost per unit "…equal to the amount of S-Sorb III that is added to the Feedstock to produce Refined Coal during such contract year." If Edison were protecting itself and its ratepayers, then why was this reimbursement limitation put in the contract. Of course, there apparently is no reimbursement for St. Clair and Belle Rivers hazardous fly ash disposal cost.

Another issue is found in the last sentence of Monroe's Section 9.4(c):

Seller shall have the right to suspend the delivery of Refined Coal hereunder if Seller is or may be required to reimburse Buyer any amounts under this Section 9.4(c).

The right of the fuels companies to unilaterally suspend the delivery of refined coal rather than reimburse Detroit Edison is found repeatedly throughout the DECo/Fuels Company contracts. This is simply unacceptable. Contractually allowing a vendor to unilaterally suspend deliveries whenever the vendor is requested to provide a contract reimbursement is not worth the paper it is written on. What happens in 2015 (or 2016) if the Fuel Company suspends providing refined coal and Edison therefore violates the Clean Air Act.

Witness Peloquin's Exhibit MCAAA- 34 illustrated the contract differences described in his testimony.

II. ARGUMENT

A. The statutory provisions and objectives of Act 304 require the production tax credits associated with DECo's coal burns to be recognized as an offset to DECo's coal costs for PSCR ratemaking purposes

MCAAA asserts that the REF production tax credit revenues are a proper offset to the cost of CECo's coal for purposes of setting just and reasonable PSCR rate factors under Act 304.

The REF production tax credits arise from DECo's coal supply chain and the burning of coal at DECo's coal plants, all developed and supported for many years by ratepayers, and arise also from DECo's customer base as a utility. Without DECo's extensive operations, financial resources, and customer base, no opportunity would exist to develop REF projects, and to be in the position to generate the REF tax credits. Thus, the tax credit revenues are integrally related to DECo's coal plants and operations, all covered by customer rates.

These cases relating to the REF tax credits appear to be the first cases in which DECo has not offset or reconciled fuel costs for refunds or credits arising from the fuel-related costs. For example, DECo and other utilities have traditionally credited FERC natural gas rate refunds against its Act 304 fuel costs, or rail or pipeline transportation refunds as an offset to said costs. The same consistent treatment should be applied here with respect to the REF production tax credit revenues, which directly relate on a per-ton basis to the coal burns at DECo's coal plants.

By ignoring the cost offsets to coal costs that should be recognized from the production tax credit revenues associated with DECo's coal burns, DECo has revealed its erroneous premise that the unregulated DTE and its subsidiary Fuel Companies may divert the tax credit benefits from DECo to themselves, and that such action escapes scrutiny and reconciliation under Act 304 on the basis that it does not <u>increase</u> DECo's costs. However, DECo's premise is erroneous. The failure to recognize the tax credit offset to DECo's coal costs <u>does increase</u> DECo's coal costs from what these costs otherwise would and should be, and also constitutes a failure by the utility to minimize its costs in accordance with Act 304. The lack of the coal cost offset also does not comport with the Act 304 process which traditionally has recognized net costs — both cost increase and decreases — including offsets such as federally determined refunds, rail transportation refunds, and similar credits analogous to the tax credit revenues at issue in this case. Quite simply, Act 304 does not establish a rate freeze or "ratchet up" statutory framework or process.

The REF transactions also ensure the diversion of a profit margin (and tax credit benefits) to the fuel company affiliates (or their third party investors), or to DTE that has or will sell interests in the fuel companies to obtain an advance "monetization" of the value of the revenue stream/tax credit benefits, at the expense of DECo (compared to the situation if DECo or DECo subsidiaries undertook the transactions as a utility). In the process, opportunities to reduce PSCR costs have been lost. At no time has DECo in its evidence or arguments denied that DTE and/or its Fuel Company subsidiaries obtained tax credit revenues, or monetization or tax credit benefits, from its REF transactions for each year since 2009, and secondly, that none of these tax credits or benefits have been subtracted from DECo's coal costs included in its PSCR. In other words, DECo's erroneous interpretation and applications of Act 304 would refuse to reconcile and include in Act 304 costs its net costs of coal (i.e., coal costs minus tax credit revenues and benefits). Rather, DECo (at the direction of its unregulated parent holding company, DTE) seeks to "privatize" for the unregulated DTE and its Fuel Company subsidiaries all tax credit revenue benefits from DECo's coal inventories and supply chain, and to "socialize" to ratepayers without offset the costs thereof.

DECo's arguments also refer to the fact that DECo's customers are not harmed by the non-recognition of the tax credit revenues or benefits because their costs do not increase. However, DECo in this case requests recognition of an underrecovery of some $148 million or more which in large part results from the non-recognition of the REF tax credit revenues or benefits as an offset to coal costs, not only in this case but in previous PSCR cases. Moreover, this non-recognition of major REF offsets to coal costs will be accumulating and will become ever more severe with each passing year of the 10 year REF tax credit program. This places immense unwarranted burdens upon ratepayers which violates the judicial standard that the Commission must balance the interests of stockholders and ratepayers [*City of Detroit v Michigan Public Service Comm'n,* 308 Mich 706; 14 NW2d 784 (1944), *Union Carbide Corp v Public Service Commission*, 431 Mich 135; 428 NW2d 322 (1988)].

DECo's position on this issue is unprecedented and also does not comport with previous case results involving analogous circumstances. For example, when it was found that CECo was engaging in forced burns of oil at its Karn plants to consume excess oil shipments CECo received under contract with the Union Carbide Corporation, the Commission ultimately protected ratepayers by requiring Act 304 refunds or cost offsets to remove scores of million of dollars in excess costs from Act 304 rate factors. The Commission's order was affirmed by the reviewing Court in *Consumers Energy Company v MPSC*, 196 Mich App 687 (1992). Another analogous example is the result which occurred in the consolidated MichCon case U-14800/U-15042 (the latter docket being MichCon's GCR case for the 12-months ending March 31, 2008). In that case, MichCon was <u>not</u> ultimately permitted to retain the proceeds of the sale of excess storage gas reserves that MichCon had arranged to sell at market prices. Instead, as a result of litigation and settlement discussions in that case, the parties ultimately reached a settlement whereby the proceeds of the gas sales were shared as between ratepayers and the utility, along with other provisions whereby MichCon committed to undertaking certain studies and pilot energy efficiency programs.[1]

DECo in these REF cases has also made unfounded claims that customer benefits of the REF program include a reduction in Detroit Edison's working capital expense by not carrying coal inventory," or reductions in emission allowances expenses, or a cap on never paying more than the value of environmental benefits received. However, these assertions are highly questionable. The "Fuel Companies" are going to charge Edison for their capital costs, including a return on their investment in fuel inventory, fuel inventory which otherwise would have been on the books of Detroit Edison. The result is a zero net savings for working capital.

Rather than a savings, the aspect of the "Fuel Companies" owning fuel inventories is going to result in double recovery of capital costs related to these fuel inventory. A review of the Commissions' October 26, 2011 Order in Case No. U-16472 (DECo's most recent general electric rate case), establishes that there is no reference to a reduction of DECo's working capital ratebase specifically for fuel transferred to REF projects.

DECo's projected test year in its rate case, U-16472, did not apparently include a downward adjustment to working capital to account for the REF transactions. With respect to working capital costs for coal inventory, said costs at minimum would be recovered in DECo's base rates (if no REF transactions occurred) or would be covered by charges by the fuel companies to DECo under the REF arrangements. Therefore, DECo customers are being charged for all DECo fuel inventory, including any transfers to REF projects. At the very least, a

[1] The settlement, and MPSC order approving same, dated August 21, 2007, provided for an offset to costs and customer rates of approximately $20 million of the sale proceeds, along with Mich Con’s commitment to conduct in-depth studies regarding gas storage and accounting issues, and to fund and implement pilot residential energy efficiency programs for the years 2008 and 2009, and to propose an expanded energy efficiency program in its next rate case.

savings in working capital from "reduced" coal inventories would not result because such costs would still be recovered within the charges rendered to DECo by the Fuel Companies.

With respect to future claimed savings in emission allowance expenses, such savings are highly speculative and may indeed be illusory. DECo’s assertions of an expense "cap" under the REF transactions are largely under the control of complicated internal calculations controlled by DTE, DECo, or the fuel companies, and in any event, do not address the problem of DECo losing opportunities to reduce costs and to share in the tax credit benefits.

The REF transactions also curtail or greatly complicate the audit trail for DECo's fuel expense. For example, DECo's proposal is for the St. Clair Fuel Company to take delivery of St. Clair (and presumably Belle River) coal at the MERC transshipment facility at Superior, Wisconsin. Thus, all of the records pertaining to DTE's western coal after receipt by MERC until delivered to the St Clair (and Belle River) power plants' coal conveyors would be in the possession of a non-jurisdiction DTE Energy subsidiary. At the same time, innumerable numbers of DECo employees continue to do the work associated with DECo’s coal supply chain, while each of the Fuel Companies have only three (3) employees or less, as revealed in the record in this case (U-16434-R).

The Commission should also consider a disallowance of the cost increases (or lost coal cost reductions) associated with the REF transactions in 2010 that were never proposed or revealed in the 2010 Plan Case, U-16047, or which are prohibited by various provisions of Act 304. Sections 6j(13)(a), (d), (e), and (g) of Act 304, MCL 460.6j (a), (d), (e), and (g), provide in relevant part:

> (13) In its order in a power supply cost reconciliation, the commission shall:

> (a) Disallow cost increases resulting from changes in accounting or rate-making expense treatment not previously approved by the commission. The commission may order the utility to pay a penalty not to exceed 25% of the amount improperly collected.
>
> * * *
>
> (d) Disallow transportation costs attributable to capital investments to develop a utility's capability to transport fuel or relocate fuel at the utility's facilities and disallow unloading and handling expenses incurred after receipt of fuel by the utility.
>
> (e) Disallow the cost of fuel purchased from an affiliated company to the extent that such fuel is more costly than fuel of requisite quality available at or about the same time from other suppliers with whom it would be comparable cost beneficial to deal.
>
> * * *
>
> (g) Disallow additional costs resulting from unreasonably or imprudently renegotiated fuel contracts.

The REF transactions indeed relate to the functions described in the above statutory provisions. At no time did DECo obtain advance approval of the REF transactions as required under Section 6j(13)(a). DECo has also failed to carry its burden of proof to establish that DECo has met the requirements of Section 6j(13)(d), (e), and (g) quoted above.

B. The Production Tax Credit revenues could have been realized by DECo or a DECo subsidiary rather than being diverted to unregulated subsidiaries of the unregulated DTE parent company -- a situation that can be corrected through the adoption of appropriate ratemaking remedies

Certain parties to these REF cases, such as the MPSC Staff and DECo, have erroneously suggested that the provisions of the Internal Revenue Code (IRC), specifically Section 45, prohibit ratemaking recognition of the tax credit benefits or monetization revenues generated under IRC Section 45 for the handling and processing of Reduced Emissions Fuel (REF) coal at DECo’s coal plants.

DECo in this and other cases has also presented non-qualified third-hand testimony intimating that the creation of affiliated Fuel Companies under the unregulated parent company, DTE, and its subsidiaries, was necessary in order to realize the REF tax credits. However, this has not been established.

Major flaws exist with respect to these asserted claims or implied positions. First, the tax credit benefits or revenues were not (or are not) unavailable to DECo (or its ratepayers), either directly or indirectly, by provisions of IRC Section 45 requirements that "unrelated parties" be involved in the activity. The definitional subparagraph of the same IRC Section 45, cited by these parties, specifically states:

> Persons shall be treated as related to each other if such persons would be treated as a single employer under the regulations prescribed under section 52(b). In the case of a corporation which is a member of an affiliated group of corporations filing a consolidated return, such corporation shall be treated as selling electricity to an unrelated person if such electricity is sold to such a person by another member of such group.

This liberal and expansive definition of "unrelated parties" in Section 45(e)(4) clarifies that there was no bar (and is no bar) to <u>DECo</u> forming separate subsidiaries to capture the tax credits and revenue benefits for the utility (DECo), as opposed to DTE Energy or its affiliate, DTEES. In other words, the tax credits or revenue benefits thereof could just as easily have been derived for the benefit of DECo, rather than the unregulated DTE or its affiliates, in order to meet the prerequisites of obtaining the tax credits or benefits under IRC Section 45.

Serious problems exist with respect to unfounded assertions or suggestions concerning the requirements of IRC Section 45. First, such assertions or suggestions are wholly unsupported by "competent, material and substantial evidence" as required by both Constitutional and statutory standards.[2] The MPSC Staff did not even present any expert testimony in this case whatsoever, and therefore its assertions made for the first time in briefing are unsupported by the record. No qualified or expert witness by DECo had the expertise or qualifications to make such claims regarding the requirements of Section 45, nor has DECo in any of its briefings provided any assertions, signed by counsel, as to such claims. No party to this case has cited any IRS private ruling, regulatory interpretation, or any other authority issued by the IRS or by a court to support the unsupported claims made by the Staff or DECo relative to the requirements for capturing the subject tax credit benefits.

Moreover, DECo's witnesses revealed in this case that DECo sought no independent tax advice or independent tax counsel and that the creation of the Fuel Companies as subsidiaries of DTE rather than of DECo occurred as a result of a "top-down" (DTE controlled) decisional process.

The DECo Witness who references the tax issue also was not qualified as either a tax lawyer or tax expert, and he did not refer to any tax regulation, IRS interpretation, or case that supported the unsupported theory that the Fuel Companies had to be set up as subsidiaries of DTE rather than under DECo. The DECo witnesses' vague assertions thus must be disregarded under controlling judicial principles applied to experts, such as in *Daubert v Merrell Dow Pharmaceuticals,* 509 US 579; 113 S Ct 2786; 125 L Ed 2d 469 (1993), Const 1963, art 6, § 28, and Section 85 of the Administrative Procedure Act, MCL 24.285, the Commission's finding to "be supported by competent, material and substantial evidence on the whole record." Expert testimony meets this test only if presented by a ***qualified*** expert who has an ***informed*** basis for

[2] Article 6 Section 28 of the Michigan Constitution of 1963, Section 85 of the Michigan Administrative Procedures Act (APA), MCL 24.285, and prevailing precedent.

his testimony.[3] No witness presented by DECo could testify on the requirements of IRS Section 45, and DECo presented no substantive briefing concerning Section 45, such as Court precedent, IRS regulations, or IRS opinions or private letters, or any other supporting authority. The Commission therefore has no basis for adopting such claims or assertions in this case.

Another major problem with the arguments made by MPSC Staff or DECo is the implication that Section 45 would in any way affect or have any relevance to the MPSC's ratemaking authority. Section 45 dealing with the obtaining of production tax credits for REF coal processing did not, and do not, in any way complicate ratemaking recognition of the tax credits or the revenue value of the tax credits. No party has cited any provision in either IRC Section 45, or any other Section of the IRC, that in any way affects the manner in which the state regulatory commission should regulate the rates of the regulated utility with respect to production tax credits and revenues associated with the processing of coal under REF projects. Certainly, any implication of federal preemption of state ratemaking authority with respect to the treatment of the subject tax credits (or monetization of revenues arising thereby) has not been claimed by any party. The Congress, in the Federal Power Act, has expressly provided for the division of regulation of electric rates with respect to separate interstate and intrastate spheres. The MPSC also has the primary regulatory jurisdiction under state statutes to review the ratemaking treatment of the REF issues, fully consistent with Congress' demarcation in the regulation of utilities between the federal and state governments. Congress in Section 201(b) of the Federal Power Act, 16 USC § 824(b), expressly preserved state ratemaking and other

[3] *Great Lakes Steel v Public Service Comm,* 130 Mich App 470, 481; 334 NW2d 321 (1983)., *General Electric Co v Joiner,* 522 US 136, 146; 118 S Ct 512; 139 L Ed 2d 508 (1997), quoted with approval in *Gilbert v Daimler Chrysler Corp,* 470 Mich 749, 783; 685 NW2d 391 (2004). *Daubert v Merrell Down Pharmaceuticals, Inc,* 43 F3d 1311, 1316 (CA 9, 1995).

regulation over retail electric sales. *Connecticut Light & Power Co v FPC*, 324 US 515 (1945); *New York v Federal Energy Regulatory Comm*, 535 US 1 (2002); *Detroit Edison v FERC*, 334 F3d 48 (2003). The proper recognition of tax credits or monetization revenues derived therefrom by the state ratemaking commission also would not interfere with the purposes and objectives of Congress either with respect to administration of the Internal Revenue Code or electric ratemaking, or environmental compliance. Again, no party has even hinted at such claims in this case.

To be certain, a utility subsidiary could qualify as a "non-regulated entity" just as easily as a DTE affiliate, and the REF transactions could have been similarly conducted through the use of a DECo subsidiary.

The establishment of the Fuels Company affiliates, under DTE rather than under DECo, had the purpose of facilitating the diverting of the tax credit revenues as an offset to coal costs for ratemaking purposes for the profit making benefit of DTE. This purpose is contrary to the objectives and purposes of Act 304, and the duties to both the MPSC and the utility under Act 304.

Based upon the above, the Commission retains full authority to "roll-in" or otherwise recognize for ratemaking purposes all of the tax credit benefits, or monetization of revenues derived therefrom, realized by the Fuel Companies with respect to the handling and processing of the coal at DECo's plant sites. The Commission should undertake such ratemaking remedies.

C. The diversion of the production tax credit revenues from being an offset to DECo's coal costs for ratemaking purposes, to DTE's unregulated affiliates, constitutes an abuse of affiliated transactions

MCAAA asserts that the diversion of the REF production tax credit revenues to unregulated affiliates of DTE in lieu of being recognized as an offset or credit to DECo's coal costs, constitutes the kind of intercorporate affiliated transaction that should be scrutinized and remedied by the MPSC in this and other ratemaking cases.

The situation in this and other cases whereby DTE seeks to divert REF production tax revenues away from the ratemaking process is just another example of such affiliated transactions. The Commission should therefore remedy this situation to protect ratepayers, just as the Commission and Courts have done so in other analogous cases and circumstances.

Both statutory and case law establish that the Commission can and should scrutinize affiliated transactions in order to set and maintain just and reasonable rates and in otherwise protecting ratepayers. Affiliated transactions between a regulated utility and its unregulated affiliates can adversely impact the regulated utility's costs and rates, including both the base rates and Act 304 rates.

The Commission has broad jurisdiction and authority to review and adopt ratemaking remedies to deal with affiliate transactions under its enabling acts and Act 304 to: (1) set and maintain "just and reasonable" base rates and also rate surcharges or credits for fuel and purchased power costs regulated under Act 304;[4] (2) to regulate the books, records and

[4] *Attorney General v PSC*, 189 Mich App 138, 146 (1991), *Northern Michigan Water Company v Public Service Commission*, 381 Mich 340, 351 (1968). Sections 4(a) and (b), 6(a), 10(g), 22 and 32 of the Railroad Act, 1909 PA 300, MCL 462.4(a) et seq.; Section 8 of the Public Utilities Commission Act, 1919 PA 410; MCL 460.58 et seq., Sections 6 and 6a of the Public Service Commission Act 1939 PA 3, MCL 460.6 et seq., and Section 7 of the Electric Transmission Act, 1909 PA 106, MCL 460.557 et seq.

accounting of utilities, and (3) to require reports, production of documents, and to undertake investigations as to utility costs and rate matters, and to establish rules and regulations governing utilities and the regulation thereof.

The MPSC has inherited all of the jurisdiction, duties, and authority previously possessed by its predecessor commissions, the Public Utilities Commission and the Michigan Railroad Commission, *Union Carbide Corporation vs. Public Service Commission*, 431 Mich 118, 150, 155-156 (1988); Section 4 of the Public Service Commission Act, MCL 460.4; Section 4 of the Public Utilities Commission Act, MCL 460.54. The Commission therefore has broad ratemaking authority over CECo's rates pursuant to all of the various "enabling acts" applicable to the Commission.[5]

General rate cases and Act 304 PSCR proceedings are also subject to formal contested case procedures, as set forth in Section 6a and MAPA. The Commission is to make legal and factual findings and to render its decision based upon the whole record, as formulated by the parties (MAPA Section 85, MCL 24.285). The Commission has also established the *Commission's Rules of Practice and Procedure Before the Commission*, 1992 AACS, R 460.17101 *et seq*., to govern contested rate and other procedures. These rules incorporate the Michigan Court Rules relative to numerous matters, including the issuance of subpoenas,

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[5] These statutory provisions include Section 6 and 6a of the Public Service Commission Act, MCL 460.6 and MCL 460.6a, as amended by 1982 PA 304, MCL 460.6 et seq., and MCL 460.6a et seq., (Act 304), and 2000 PA 141, Section 10-10cc, MCL 460.10 et seq. (Act 141), Section 4 et seq. of the Public Utilities Commission Act, MCL 460.54 et seq., Section 2 et seq. of the Railroad Act, MCL 462.2 et seq., the Electric Transmission of Electricity Act, Section 1 et seq., MCL 460.551 et seq., the Electric Transmission Line Certification Act, Section 1 et seq., MCL 460.561 et seq., and related statutes. The Commission is also subject to the procedural requirements of Michigan's Administrative Procedures Act ("MAPA"), MCL 24.201 et seq., and the Commission's own Rules of Practice and Procedure Before the Commission, 1992 AACS R 460.17101 et seq. ("Commission Rules").

discovery, the taking of depositions, and numerous other matters. Our courts have affirmed the Commission's widespread authority to undertake discovery in contested cases, and to obtain all necessary information to regulate the rates and books of all utilities. *Midland Cogeneration Venture Ltd and Consumers Power Co v Michigan Public Service Comm'n*, 199 Mich App 286; 501 NW2d 573 (1993). These procedures give the Commission, and parties participating in contested rate and PSCR proceedings, enhanced powers to investigate and to require the production of information concerning claimed costs and requested rates.

The Commission also has specific jurisdiction and authority to investigate rate and service issues, and actions, practices, or omissions of utilities, and to commence proceedings to protect ratepayers and to undertake corrective action pursuant to the filing of a formal complaint.[6] Section 8 also provides the Commission with the authority to hold hearings, to subpoena witnesses, and require the production of books and records, for purposes of investigating and ruling upon the subject matter of the complaint. Section 7 also provides the Commission broad powers to investigate and hold hearings regarding the subject of the complaint, and to inspect the books and records of a utility and to inquire into the matters relating to the complaint.

The Commission also has extensive jurisdiction and authority to regulate the books, records and accounting of utilities, to require the filing of reports, the production of documents, and to undertake investigations as to utility costs and rate matters, and to require utilities to maintain and produce for review information, data, and contracts as needed by the Commission

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[6] Section 8 of the Public Utilities Commission Act, MCL 460.58, Sections 4 and 6 of the Public Service Commission Act, MCL 460.4 and MCL 460.6, Section 7 of the Transmission of Electricity Act, MCL 460.557; and Sections 10(g) and 22 of the Railroad Act, MCL 462.10(g) and 462.22. The Commission Rules, R 460.17101 *et seq.*, including Rules 501 – *et seq.*, R 460.17501 *et seq.*

to properly regulate and perform its duties, and to establish rules and regulations governing utilities and the Commission's regulation thereof.[7] The Commission is empowered with respect to a rate, service, or other investigation to make an audit and analysis of the books and records of a utility. Section 6, Public Utilities Commission Act, MCL 460.556, Section 28, Railroad Act, MCL 462.28.. The Commission also has established a Uniform System of Accounts for Major and Nonmajor Electric Utilities (R 460.9001 and R 460.9019), which governs the manner in which utilities are to keep their books for regulatory purposes.

The Commission also has jurisdiction and authority to issue declaratory rulings regarding its jurisdiction and authority, and regulatory matters, pursuant to MAPA Sections 33, 63, and 64, MCL 24.233 et seq., and Rule 701 of the Commission's Rules, 1992 AACS R 460.17701.

The Commission's authority above has been further clarified and buttressed by the federal statutory changes under the 2005 EPAct. Federal law now delegates to the states enhanced authority to scrutinize holding company transactions as part of the elimination of most previous provisions of the federal Public Utility Holding Company Act (PUHCA), as indicated by Section 1265, 42 USC §1265, which states:

> SEC. 1265. STATE ACCESS TO BOOKS AND RECORDS.
>
> (a) IN GENERAL. - Upon the written request of a State Commission having jurisdiction to regulate a public-utility company in a holding company system, the holding company or any associate company or affiliate thereof, other than such public-utility company, wherever located, shall produce for inspection books, accounts, memoranda, and other records that-
>
> (1) have been identified in reasonable detail in a proceeding before the State commission;

[7] Sections 2, 28, and 29 of the Railroad Act, MCL 462.2 *et seq.* Sections 3, 4, 5, 6, 7, and 8 of the Public Utilities Commission Act, MCL 460.53 *et seq.*, Sections 6, 6a, and 6j *et seq.*, of the Public Service Commission Act, MCL 460.6 *et seq.*, and Sections 6 and 7, of the Electric Transmission Act, MCL 460.556 *et seq.*

(2) the State commission determines are relevant to costs incurred by such public-utility company; and

(3) are necessary for the effective discharge of the responsibilities of the State commission with respect to such proceeding.

(b) LIMITATION. - Subsection (a) does not apply to any person that is a holding company solely by reason of ownership of one or more qualifying facilities under the Public Utility regulatory Policies Act of 1978 (16 U.S.C. 2601 *et seq.*).

(c) CONFIDENTIALITY OF INFORMATION. - The production of books, accounts, memoranda, and other records under subsection (a) shall be subject to such terms and conditions as may be necessary and appropriate to safeguard against unwarranted disclosure to the public of any trade secrets or sensitive commercial information.

(d) EFFECT ON STATE LAW. - Nothing in this section shall pre-empt applicable State law concerning the provision of books, accounts, memoranda, and other records, or in any way limit the rights of any State to obtain books, accounts, memoranda, and other records under any other Federal law, contract, or otherwise.

(e) COURT JURISDICTION. - Any United States district court located in the State in which the State commission referred to in subsection (a) is located shall have jurisdiction to enforce compliance with this section.

A 2006 research article provides insightful descriptions of the dangers involved relative to affiliated transactions, and also the impact of EPAct 2005[8]

> Technically, in repealing PUHCA 1935, Congress in § 1263 of EPAct 2005 substituted a new Public Utility Holding Company Act of 2005 (PUHCA 2005)[9]. PUHCA 2005 is much more limited than the original, however. The broad authority of the Securities and Exchange Commission under PUHCA 1935 to regulate public utility holding companies is replaced primarily with statutory provisions dealing with access to books and records for both state commissions and the Federal

[8] "*Repeal of the Public Utility Holding Company Act of 1935: Implications and Options for State Commissions*", by Robert E. Burns and Michael Murphy, the Electricity Journal, Volume 19, Issue 8, October 2006.

[9] *The Public Utility Holding Company Act* of 2005, 42 USC § 1261 *et seq.*

> Energy Regulatory Commission (EPAct 2005 §§ 1264 and 1265). Both state commissions and FERC have the ability to check affiliate transactions (§ 1267). And both state commissions and FERC have the authority to deal with cost allocations and cross-subsidies. For the analysis in this article, it is also important that PUHCA 2005 authorizes the states and federal agencies to protect utility customers with "otherwise applicable law" (§ 1269).
>
> * * *
>
> The savings provision in EPAct 2005 § 1265 provides that, under otherwise applicable state laws, state commissions are allowed to gain access to books and records. State commissions are also not precluded form exercising their authority under otherwise applicable laws to determine whether a utility company may recover in its rates any costs of an activity performed by an affiliate, or any costs of goods or services acquired by the utility from the affiliate. There is another savings provision in PUHCA 2005 pursuant to EPAct 2005 § 1267 that makes this clear.[10] A state commission could obtain books and records through exercise of its own authority pursuant to state statute, commission could obtain books and records through exercise of its own authority pursuant to state statute, commission rule, or order. Such state authority might be broader than the federal access to books and records discussed above.
>
> EPAct 2005 § 1275 contains an explicit savings provision that allows state commissions to continue to exercise their authority under otherwise applicable law to deal with cost allocation and cross-subsidy issues.[11]

Michigan judicial authority has held that the MPSC may and should scrutinize and remedy intercorporate affiliated transactions of a holding company whereby the unregulated parent company and its affiliates reap profits under the guise of expenses passed through to customers of a utility where no protections inherent in arms-length bargaining is present. *Michigan Bell Telephone Co v Public Service Commencement*, 85 Mich App 163; 270 NW2d 546 (1978), *CMS Energy Corp v Attorney General*, 190 Mich App 220, 475 NW2d 451 (1991), *Midland Cogeneration Venture Limited Partnership, et al v Michigan Public Service Commission, et al,* 199 Mich App 286; 501 NW2d 573 (1993), and *In re Application of Detroit Edison Company*, Supreme Court dockets 134667, 134668, 134669, 134671, 134672, 134674,

[10] EPAct 2005, Section 1267(b).

[11] EPAct 2005, Section 1275 (c).

134767, and 134677, where the Michigan Supreme Court in its May 1, 2009 Order affirmed the Commission's order, thereby reversing and vacating a Court of Appeals decision in *In re Application of Detroit Edison Company*, 276 Mich App 216 (2007).

The record establishes that the REF proposal intrudes deeply into integral utility functions and costs that should remain under the utility's control and remain subject to transparent regulatory review by the Commission. The REF transactions overall involve a construct in which the newly established "fuel company" affiliates will earn an unregulated profit (plus the realization of significant tax credit benefits) at the expense of the utility. While DECo claims that DECo's costs are capped, this does not remove the obvious fact that the fuel affiliates will undoubtedly realize profits and tax benefits at DECo's expense. The overall proposal establishes a construct whereby the unregulated affiliates have been interjected into major basic supply chain functions of DECo involving coal transportation, inventory management, and coal handling. The fuel company affiliates are set up to divert opportunities for DECo itself to have reduced its coal costs by undertaking the REF functions itself so as to realize the tax credit revenue benefits involved. The profit that the fuel company affiliates earn, along with the tax credits that they have obtained, by the REF transactions are derived in reality at the expense of DECo and its ratepayers. Inherently, these profits and tax credits are derived from cost decreases or tax benefits that otherwise would go to DECo if DECo had undertaken the REF program itself or through DECo subsidiaries and not through fuel company affiliates set up by DTE.

MCAAA also asserts that the unwarranted REF benefits diverted to DTE and its unregulated affiliates, at the direct expense and detriment of DECo's customers, is contrary to the plain language and objectives of Act 304. The record in this case (U-16434-R), establishes that each of the Fuel Companies set up to handle or process REF coal at DECo's plants have only <u>three or less</u> employees. In contrast, the long-standing entire coal supply chain of DECo, which has been established over many decades, includes thousands of employees engaged in administration, contracting, legal matters, coal acquisition, rail and vessel transportation, among a myriad of other functions that makes it possible for DECo's vast coal inventories to arrive at each of its coal generating plants. The records in all of the cases on this issue have revealed, by DECo's own witness admissions, that DECo handles all of the administration and other functions in the coal supply chain, while the Fuel Companies <u>with three or less employees</u> each admittedly must undertake the most bare bones, artificial, and limited functions. Yet, the Fuel Companies claim to generate many millions of dollars annually, by obtaining tax credits of $6.33 per ton as of 2010 (to be escalated annually) for each of the millions of tons of coal inventories assigned to the REF process.

DECo's witnesses have also admitted that Detroit Edison sells its coal inventories to the Fuel Companies, and then buys the coal back from the Fuel Companies at the same price (with relative minor adjustments related to cost adders, coal ash adjustments, etc). DECo therefore admits that the Fuel Companies sell the REF coal back to DECo at a price that <u>does not</u> reflect a subtraction for the per-ton tax credit generated under the tax code (which was $6.33 per ton for the reconciliation year 2010). Considering the vastness of the long standing coal supply chain of DECo, which long pre-dated the creation of the DTE parent holding company and its subsidiaries, and given DECo's remaining and existing responsibilities and costs related to this coal supply chain (in contrast to the artificial, anemic, self-serving, and recent creation of Fuel Companies with only three employees each) that an incredible imbalance now exists by which DECo is being taken advantage of (along with its customers) so as to provide unwarranted, unearned, windfall benefits to DTE's unregulated affiliates (namely DTE, and its affiliates DTEES and the Fuel Companies).

The reality is that the cross-subsidies and transfer of windfall benefits to the unregulated affiliates in the DTE holding company system are not limited to the shocking situation described above. In fact, the record in this case (U-16434-R), establishes that unacceptable cross-subsidization logically exists in several other ways. For example, there is no evidence in the record in this or other cases that the Fuel Companies deriving the benefits of fuel credit revenues adequately compensated DECo's vast coal supply chain network and costs for the function of acquiring and delivering the coal to DECo's plant sites, with an appropriate margin or rate of return to compensate this supply chain for these vast activities. There is no analysis as to what the cost and benefits would be if DECo (or its own separate affiliates or subsidiaries) had undertaken the same REF process itself so as to capture the tax credit revenue benefits while still complying with IRC Section 45. The evidence in various cases, including U-16434-R, also established that DTE as the controlling holding company has placed and required the placement of excess REF production units at DECo's coal plants, in excess of what DECo would require (one unit per plant) to meet REF processing for its own purposes. This means that DECo has been utilized as the "guinea pig" to develop a market for the unregulated DTE and its affiliates to then sell the REF production units and process to other third parties. In fact, the record in this case (U-16434-R) establishes that DECo has already relocated excess REF production units, tested and developed at DECo's sites (at DECo's expense) to other out-of-state locations, including Oklahoma and Illinois. This creates another form of cross-subsidization of the utility in favor of unregulated affiliates in the DTE holding company system (which controls the subsidiary DECo) in a manner which is unwarranted.

This situation strongly supports dramatic action by the Commission to reject DECo's REF proposals, and to block the associated cross-subsidization inherent in such inter-affiliated corporate abuses, and to remedy the resulting extreme imbalance relating to utility stockholder and customer interests.[12]

The approach advocated by DECo and the MPSC Staff in these REF cases also flies in the face of the standards and criteria of Act 304 itself which requires the utility to carry its burden of proof to demonstrate all regulatory actions undertaken to minimize its PSCR costs. The reality is that the decision by the unregulated holding company, DTE, and its creation of affiliates to take advantage of DECo, constitutes an affiliated transaction abuse which the Commission should curtail, limit, and reverse, consistent with the statutory and judicial authority cited above.

The MCAAA also cautions against the Commission misanalyzing this case as one involving simply reductions or disallowances from the cost of coal as advocated by DECo. In other words, this case does not involve simply the disallowance of the cost of a Fuel Companies adder or of some miscellaneous O&M cost, or of minor other costs. The major issue is actually straightforward, that is, that DTE as a holding company has utilized its affiliated intercorporate structure and power to seek to divert scores of millions, if not hundreds of millions of dollars, over a ten year period to the benefit of its unregulated company structure at the direct expense (or lack of recognition of a coal cost offset) of DECo's customers. This is in the context of the corporate structure in which DECo has no power to defend itself as compared to a situation where it was a separate independent utility. The Commission's regulatory ratemaking duties must override the corporate strategies of a self-serving unregulated holding company system which seeks to pass through or maintain costs of the captured utility to its customers while

[12] Michigan Supreme Court precedent established that the duty of the Commission is to balance the interests of utility stockholders and customers (e.g., *City of Detroit v MPSC*, 308 Mich 706; 14 NW2d 784 (1944); *Union Carbide v MPSC*, 431 Mich 135; 428 NW2d 322 (1988)).

capturing for itself the unearned and windfall benefits of associated tax credits or refunds integrally related to the same fuel supply chain. The failure of the Commission to recognize the importance of its jurisdiction under act 304 to prevent such a holding company abuse will destroy the authority of the Commission under the plain language and purposes of Act 304 to the detriment of the public interests adopted by the people of Michigan.

D. The record establishes that significant REF tax credit revenues have been diverted from being accounted for as coal cost offsets for this 2011 PSCR reconciliation year

The record in this and other cases also establishes that significant REF tax credit revenues have been diverted to the unregulated DTE affiliates and away from being accounted for as an offset to DECo coal costs commencing in the 2010 PSCR year and during this PSCR year.

The 2010 SEC 10-K reports of DTE/DECo presented by MCAAA in U-16047-R (and quoted in Facts, *supra*) also establish that DTE (or Fuel Companies) realized REF production tax credits in 2010.

MCAAA's testimony and exhibits in this case (summarized in Facts, *supra*) also establishes that significant REF tax credit revenues are associated with this 2011 PSCR year. In fact, over the 10-year period of the REF tax credit program, the revenue diversion can easily exceed $500 million (e.g., Crandall Facts, *supra*, and Exhibit MCAAA-5). Also, Exhibit MCAAA-9 (MCAAA/DE-62(49), p 2), comprising a discovery response by DECo, states in relevant part:

> In 2011, the Company spent $77,868,516 on refined coal and resold coal from the Belle River Fuels Company (BRFC), $87,107,457 on refined coal and resold coal from the St. Clair Fuels Company (SCFC), and $54,481,612 on refined and resold coal from the Monroe Fuels Company (MFC).

DECo's erroneous premise is that the issues regarding REF coal transactions in this case involves a review of only (affirmative) costs or cost increases, coupled with DECo's assertions that no REF costs exist in this case. MCAAA's evidence and briefing arguments assert that the tax credit revenues and benefits are derived from and associated with DECo's coal supply chain, and should constitute offsets or reductions to DECo's coal costs (negative cost adjustments to determine DECo's net cost of coal) in this case. The failure to offset the tax credit revenues associated with DECo's coal and utility related operations would result in a failure to determine the DECo's proper <u>net</u> coal costs to be recognized for ratemaking purposes in this case.

Importantly, DECo has <u>not</u> asserted that <u>no</u> production tax credit benefits were monetized or were realized by DTE and its specially created Fuel Company or other subsidiaries (which were established as an affiliated company contrivance to divert the tax credit revenue benefits away from being an offset to DECo's coal costs). Instead, DECo has refused to provide said information through discovery or through the hearing process.

E. The REF transactions demonstrate that DECo has not complied with the letter and spirit of the Commission's Code of Conduct and affiliated transaction guidelines

MCAAA also asserts that DTE's/DECo's REF transactions also demonstrate that DECo has not complied with the letter and spirit of the Commission's Code of Conduct and affiliated transaction guidelines. MCAAA's testimony and exhibits in this and related Act 304 cases demonstrates this.

As a caveat, however, MCAAA asserts that the primary standards and criteria applicable to the utility's cost minimization duties, and the Commission's regulatory duties, are established by statute, including Act 304, and by prevailing judicial precedent. Commission regulatory orders creating a non-statutory Code of Conduct does not dispense with or displace the regulatory ratemaking scheme mandated by statute.

The record and arguments in this case, along with the ALJ's PFD in U-16892, establish that DECo has violated the Commission's Code of Conduct and the affiliated transaction guidelines. This conclusion is clear by the numerous instances of cross-subsidization that have occurred and are occurring under the REF transactions. The failure of the Fuel Companies to sell the coal back to DECo at a price that is discounted for the per-ton tax credits generated by the Fuel Companies justifies the conclusion that improper cross-subsidization under the Code of Conduct and affiliated transaction guidelines has (and is) occurring (DECo's witnesses have admitted that the coal buy back occurs at the same price, with further upward adjustments, without discount for the tax credit benefits).

Moreover, the record strongly suggests that the market price for coal at St. Clair, Michigan, is or should be regarded as being <u>higher</u> than DECo's costs and thus the sale of DECo coal inventories to the fuel company affiliates at DECo's costs underprices the revenues DECo should receive for these sales. The problem is compounded by the fact that the Fuel Companies will sell the coal back to DECo at a profit (while important tax credit benefits are captured by the fuel companies or their third party investors, and <u>not</u> DECo).

The PFD in U-16892 also properly found non-compliance by DECo of the Code of Conduct. As an example, the U-16892 PFD states:

> By artfully structuring layers of corporate ownership and investment partners to take advantage of the available tax credits, DTE Energy has devised a scheme to generate substantial profits from the chemical treatment of Detroit Edison's coal. (PFD, p 84).

* * *

> Detroit has agreed to contractual relationships with its affiliates for the provision of REF for a ten year period. Under these agreements, the affiliates stand to profit considerably…. (PFD, p 86).

The PFD at p 71 also cites Section IIB of the Code:

> B. An electric utility's… regulated services shall not subsidize in any manner, directly of [sic] indirectly, the unregulated business of its affiliates or other separate entities.

While the U-16892 PFD opines that Edison is not in compliance with the Code of Conduct, it fails to specifically find that Edison's transfer pricing is a violation. The PFD states:

> If Detroit Edison's affiliate provides services, products, or property to Detroit Edison, compensation for services and supplies shall be at the lower of market price or 10% over fully allocated embedded cost and transfers of assets shall be based upon the lower of fully allocated embedded cost or market price….

In turn, DECo has claimed that the fuel companies asymmetric transfer pricing complies with the Code of Conduct. However, the fuel companies' embedded cost is <u>not</u> the price that they initially pay Edison for the coal. Edison artfully crafted its new corporate structure to ensure that the REF tax credits were captured by the fuel companies. Therefore, the embedded coal cost of the fuel companies includes (or is reduced by) the REF Tax Credits that they (instead of DECo) generate.

The Commission should rule that the gross REF Tax Credits generated in 2011, and other PSCR years, be reconciled in this case. This dollar amount can be determined. However, DECo is the only party that can document and justify any costs that it believes should be netted against the gross REF Tax Credits. This burden should be placed upon DECo, and its affiliates, which have full access to this data, unlike any other party.

The lack of DECo's compliance with the Code of Conduct and affiliated transaction guidelines, as well as the standards of Act 304, is also established by the lack of forthrightness by DECo concerning the REF projects, the resulting tax credit benefits, and DTE's creation of unregulated affiliates to capture the tax credit benefits in contrast to the creation of DECo affiliates to capture such benefits. DECo never provided forthright advance disclosures of the REF program and associated tax credit revenues. DECo also never filed for an advance approval of the accounting and ratemaking treatment of same, before or during the 2010 Plan case. DECo in this case also refused to answer discovery inquiring to the amount of tax credit revenue or tax credits "monetized" in 2010 (or at any other time). DECo has thus <u>not</u> complied with the letter and spirit of provisions of Act 304, and of the Commission orders establishing the Code of Conduct or the affiliated transactions guidelines.

F. The REF program is not necessary to meeting state or federal environmental standards, including future mercury standards--in any event, this assertion, if made, does not justify diverting the tax credit revenues away from DECo as a regulated utility

In U-16434, the Commission's order made an indirect reference to DECo's efforts to address future environmental standards, including the then expected future standards applicable to mercury emissions.

The evidence in this case includes the forthright acknowledgement by DECo Witness Rogers that the REF process is <u>not</u> necessary to meet state and federal environmental standards, including those future standards applicable to mercury standards (e.g., Rogers, T___, T___, T___). DECo Witness Rogers testified instead that such emissions standards can readily be met by other available technologies and methods (e.g., T___, T___). At the same time, DECo Witness Rogers suggested that the REF process may reduce the cost of such emission control methods, but acknowledged that such future cost comparisons and forecasts are speculative (T___, T___).

While all parties would ostensibly be in favor of reducing emissions and meeting environmental standards, the overriding logical concept here is that such goals and objectives do not justify the diversion of the REF tax credit revenues from the regulated utility (DECo) and to the DTE unregulated affiliates. In fact, the opposite is true. It would be beneficial for the utility to receive the REF coal related tax credit revenues so that the utility would be in a strong financial position to address such environmental matters, which are the direct responsibility of the utility and not of DTE or its unregulated affiliates.

G. The various contracts between DECo and the Fuel Companies demonstrate that the REF program constitutes an affiliate abuse to benefit unregulated DTE profits at the expense of DECo ratepayers

The numerous agreements between DECo and the numerous Fuels Company affiliates included in Exhibit A-30 also demonstrate that the REF program constitutes an affiliate abuse to benefit unregulated DTE profits at the expense of DECo ratepayers. While a summary of all of these contracts would be voluminous, this conclusion can be drawn from the shortcomings and "non-arms-length" provisions inherent in the contracts.[13]

The various contracts demonstrate the favoritism granted by DECo to DTE's Fuels Company affiliates. For example the contracts in reality relieve the Fuel Companies from having to deliver REF coal, and permit sales or resales of coal to third parties, and contain fairly broad warranty disclaimers and limitations of liability.

[13] A listing of the contracts, and a summary of a representative contract, such as the DECo/Belle River Fuels Company contract is attached to this Brief as Attachment A.

MCAAA Witness Peloquin, in his surrebuttal testimony (quoted Facts, *supra*) also pointed out some of the shortcomings of DECo's contracts with DTE's Fuel Companies affiliates. Witness Peloquin's Exhibit MCAAA-34 also further demonstrated his contract criticisms.

H. The ALJ should Recommend and the Commission should invoke audit and ratemaking remedies to determine the proper coal cost offsets to determine just and reasonable PSCR rates

The MCAAA asserts that the ALJ should recommend, and the Commission should adopt, audit and ratemaking remedies to determine and recognize proper REF tax credit revenues as offsets to DECo's coal costs in this and other PSCR cases.

The Commission could and should offset all PSCR rates by the revenue benefits obtained from the REF transactions and tax credits.

The Commission for many years has already utilized the "unified ratemaking approach" relative to DECo and its affiliate, the MERC coal handling facilities, ever sense the MPSC orders in U-5041 and U-5108. The same ratemaking approach could be used here to properly reconcile DECo's coal costs and to recognize as cost offsets the REF tax credit revenues derived from DECo's utility business and coal operations. Under this approach, all increased costs (or lost savings associated with the maintenance of higher costs, or tax the diversion of benefits, that otherwise would have inured to DECo if the REF transactions had not occurred) would be credited to DECo for ratemaking purposes.

MCAAA's reference to the need for a comprehensive audit and review of the books and records of DECo, DTE, and all REF-related subsidiaries, is also supported by extensive state statutory authority granting the Commission the power to undertake such audits, as augmented by the audit powers delegated to state commissions under federal law, including Section 1265 of the Public Utility Holding Company Act of 2005, 42 USC 1261, *et seq*, which is incorporated in the Energy Policy Act of 2005, as discussed earlier.

The ALJ and Commission should also order a reopening of this case and should provide for a thorough Staff audit of the REF transactions, followed by further evidentiary proceedings and supplemental briefing. While this would delay a final order in this case -- this by itself is of no significance and harms no one. In contrast, given the delayed revelations by DECo of the REF transactions, and the immense regulatory and cost implications relating to this "piece-mealing" of DECo's coal supply chain, the issue needs to be more thoroughly reviewed in this case.

The Commission should also examine what regulatory remedies are necessary to address these REF transactions, apparently undertaken by DTE on a unilateral basis and imposed upon DECo. For example, this Commission could require appropriate rate adjustments and disallowances. The Commission could order that all books and records of the fuel company affiliates will be open and available to full audits by the Commission on an ongoing basis.

The Commission should also clarify that the appropriate remedies in these REF cases are not only the rejection of any requested “cost increases,” arising from REF, but also to recognize as an offset or reduction to coal costs of the revenue benefit or value of the REF tax credits (i.e. recognition of the corresponding reduction in coal costs to account for the REF tax credit revenues or benefits). In essence, all cost and cost offset (revenues) related to coal should be rolled into Act 304 review and ratemaking.

The cost offsets to coal costs arising from the tax credit revenues or benefits should also be determined and imposed in the Act 304 cases, for each year and continuing over the 10 or more years of the REF tax credit program (and as part of the "roll-over" process the Commission used from one Act 304 year to the next).

In short, if a separate case were to be initiated with respect to the REF issues and remedies, all of the remedies provided by Act 304 for each year must nevertheless be preserved. Otherwise, the diversion of the REF issues to a separate case could disengage and destroy the rate remedies that are necessary and appropriate under Act 304 (i.e. the recognition as an offset to coal costs each year of the revenue benefit or values arising from the REF tax credits).

MCAAA also requests that the remedies should extend to requiring DECO to provide full disclosure, and open transparency, of all books and records, contracts, cost and revenue impacts, financial records, etc., of DECO, and also of DTE and all affiliates involved in the REF projects, to the Commission, its Staff, and to intervenors in Act 304 cases.

III. CONCLUSION AND RELIEF

The MCAAA requests the ALJ to recommend, and the Commission to adopt, the arguments and remedies presented by the MCAAA in this case.

Respectfully submitted,

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Dated: April 30, 2013

Listing of Agreements (and Amendments)

The Agreements, with Amendments, and/or attachments, included in Exhibit A-30, as supplemented by DECo's January 23, 2013, filing include the following:

1. **Refined Coal Supply Agreement** by and between **Belle River Fuels Company, LLC** and **The Detroit Edison Company**, dated December 4, 2009, **Amendment to Belle River Refined Coal Supply Agreement**, dated March 1, 2010;
2. **Coal Inventory Purchase Agreement** by and between **Belle River Fuels Company, LLC** and **The Detroit Edison Company**, dated December 4, 2009, and **Amendment to Belle River Coal Inventory Purchase Agreement with Detroit Edison** dated March 1, 2010, and **Amendment No. 2 to Belle River Coal Inventory Purchase Agreement** dated December 1, 2010;
3. **License and Services Agreement** by and among **Belle River Fuels Company, LLC** and **The Detroit Edison Company** and **Michigan Public Power Agency**, dated August 24, 2009, and **Amendment to Belle River License and Services Agreement** dated March 1, 2010;
4. **Environmental Indemnity Agreement** by and between **Belle River Fuels Company, LLC** and **The Detroit Edison Company**, dated August 24, 2009 and **Amendment to Belle River Environmental Indemnity Agreement**, dated March 1, 2010;
5. **Coal Handling and Consulting Agreement** by and between **Belle River Fuels Company, LLC** and **The Detroit Edison Company**, dated December 4, 2009 and **Amendment to Belle River Coal Handling Consulting Agreement**, dated March 1, 2010;
6. **Acceptance Period Coal Inventory Purchase Agreement** by and between **Belle River Fuels Company, LLC** and **The Detroit Edison Company**, dated December 4, 2009;
7. **Refined Coal Supply Agreement** by and between **St. Clair Fuels Company, LLC** and **The Detroit Edison Company**, dated December 18, 2009, and **Amendment to St. Clair Refined Coal Supply Agreement**, dated March 1, 2010, and **Amendment No. 2 to St. Clair Refined Coal Supply Agreement**, dated January 7, 2011; **Amendment No. 3 to St. Clair Refined Coal Supply Agreement**, dated September 30, 2011;
8. **Coal Inventory Purchase Agreement by** and between **St. Clair Fuels Company, LLC** and **The Detroit Edison Company**, dated December 18, 2009, and **Amendment No. 1 to St. Clair Coal Inventory Purchase Agreement**, dated December 1, 2010;
9. **Acceptance Period Coal Inventory Purchase Agreement** by and between **St. Clair Fuels Company, LLC** and **The Detroit Edison Company**, dated December 18, 2009;

10. **License and Services Agreement** by and between **St. Clair Fuels Company, LLC** and The **Detroit Edison Company**, dated September 22, 2009, and **Amendment No. 1 to St. Clair License and Services Agreement**, dated January 7, 2011;

11. **Environmental Indemnity Agreement** by and between **St. Clair Fuels Company, LLC** and **The Detroit Edison Company**, dated September 22, 2009, and **Amendment to St. Clair Environmental Indemnity Agreement**, dated March 1, 2010, and **Amendment No. 2 to St. Clair Environmental Indemnity Agreement**, dated January 7, 2011;

12. **Coal Handling and Consulting Agreeme**nt by and between **St. Clair Fuels Company, LLC** and **The Detroit Edison Company**, dated December 18, 2009, and **Amendment to St. Clair Coal Handling and Consulting Agreement**, dated March 1, 2010, and **Amendment No. 2 to St. Clair Coal Handling and Consulting Agreement**, dated January 7, 2011, and Agreement effective January 1, 2011 between **The Detroit Edison Company** ("DECO"), a Michigan corporation, and **DTE ENERGY SERVICES, INC**. ("DTEES"), a Michigan Corporation (undated);

13. **Refined Coal Supply Agreement** by and between **Monroe Fuels Company, LLC** and **The Detroit Edison Company**, dated August 21, 2011, and **Amendment No. 1 to Monroe Refined Coal Supply Agreement**, dated November 16, 2011;

14. **Pre-Closing Coal Inventory Purchase Agreement** by and between **Monroe Fuels Company, LLC** and **The Detroit Edison Company**, dated August 21, 2011;

15. **License and Services Agreement** by and between **Monroe Fuels Company, LLC** and The **Detroit Edison Company**, dated June 13, 2011, and **Amendment No. 1 to Monroe License and Services Agreement,** dated November 16, 2011;

16. **Environmental Indemnity Agreement** by and between **Monroe Fuels Company, LLC** and **The Detroit Edison Company,** dated June 13, 2011, and **Amendment No. 1 to Monroe Environmental Indemnity Agreement**, dated November 16, 2011;

17. **Coal Handling and Consulting Agreement** by and between **Monroe Fuels Company, LLC** and **The Detroit Edison Company**, dated August 21, 2011, and **Amendment No. 1 to Monroe Coal Handling and Consulting Agreement**, dated November 16, 2011;

18. **Coal Feedstock Purchase Agreement** by and between **Monroe Fuels Company, LLC** and **The Detroit Edison Company**, dated August 21, 2011, and **Amendment No. 1 to Monroe Coal Feedstock Purchase Agreement**, dated November 16, 2011.

ii. Summary of the Belle River Agreement (Listed in 1 above)

The Belle River Agreement listed as 1 above, as amended,[1] under Section 1.1 "Definitions," provides a number of definitions, some of which are provided below:

> "Coal Consultant Fee" means the Coal Fee and the Coal Consultant Reimbursable Costs as defined in the Coal Handling and Consulting Agreement.
>
> * * *
>
> "Coal Fee" has the meaning given to such term in the Coal Handling and Consulting Agreement.
>
> "Coal Yard" has the meaning given to such term in the Coal Handling and Consulting Agreement
>
> * * *
>
> "Delivery Point for Feedstock" means the point at transfer gate no. 032m053 on feed conveyor CV 23 and at transfer gate no. 03zm054 on feed conveyor CV 24, designated as "Delivery Point for Feedstock" on Exhibit B hereto.
>
> "Delivery Point for Resold Coal" means: (a) for Resold Coal that is in transit or that has been identified for delivery under a Coal Purchase Contract but is not yet in transit, the Point of Origin; and (b) for all other Resold Coal, the point at transfer gate no. 03zm053 on feed conveyor CV 23 and at transfer gate no. 03zm054 on feed conveyor CV 24, designated as "Delivery Point for Resold Coal" on Exhibit B hereto.
>
> "Delivery Point for Refined Coal" means the point at which Refined Coal is discharged from the product conveyor extending from the discharge point of the Facility onto product conveyors CV 19 and CV 20, designated as "Delivery Point for Refined Coal" on Exhibit B hereto.
>
> "Detroit Edison" means The Detroit Edison Company, a Michigan corporation.
>
> "Detroit Edison Benefits" means the amount equal to the sum of (i) the Detroit Edison FlyAsh Benefit, plus (ii) the Detroit Edison Mercury Benefit, plus (iii) the Detroit Edison SO_2 Benefit.
>
> "Detroit Edison Coal Inventory Purchase Agreements" means (i) the Acceptance Period Coal Inventory Purchase Agreement, and (ii) the Coal Inventory Purchase Agreement.
>
> "Detroit Edison Fly Ash Benefit" means the change in sales revenues and/or disposal expenses for the fly ash produced at the Belle River Power Plant while using Refined Coal as a fuel calculated in accordance with the formulas set forth in Exhibit C.

[1] The definitions quoted below reflect changes, deletions or additions made in amendments to the Agreement (as referenced in listing 1 above).

"Detroit Edison Mercury Benefit" means the benefits achieved as a result of reduced mercury emissions from the Belle River Power Plant while using Refined Coal as a fuel calculated in accordance with the formulas set forth in Exhibit C.

"Detroit Edison PA2 Expense Increase" means the increase in Detroit Edison's cost of purchasing power under PA2 power purchase agreements or any power purchase agreement entered into under the Public Utility Regulatory Policies Act of 1978, if any, that is due to Detroit Edison paying the Detroit Edison Refined Coal Adder calculated in accordance with the formulas set forth in Exhibit C.

"Detroit Edison Refined Coal Adder" means the amount calculated as set forth in Exhibit C.

* * *

"Feedstock" means coal utilized as feedstock by the Facility for the production of Refined Coal.

"Feedstock Inventory Store" means the Seller Coal deposited and present in the areas identified as "Coal Yard" and on all interconnecting conveyors shown in Exhibit B hereto (prior to crossing either the Delivery Point for Resold Coal or the Delivery Point for Feedstock, each as identified on Exhibit B hereto).

* * *

"Mer-Sorb" is a chemical additive identified in the patents listed in the Amended and Restated License Agreement, dated January 23, 2009, between Chem-Mod LLC and DTE Energy Resources, Inc.

* * *

"Point Of Origin" means the location where the Seller Coal is loaded into a railcar (or other form of transport), FOB, for transport to Seller at the Belle River Site or to any other site designated by Buyer.

* * *

"Refined Coal" means the refined coal product produced by Seller for sale to Buyer pursuant to this Agreement.

"Refined Coal Price" means the per Ton amount equal to the sum of (i) the Coal Inventory Price multiplied by a fraction, the numerator of which is the amount of Feedstock (by weight in Tons and as agreed to by the Parties) used to produce one Ton of Refined coal at the Facility, and the denominator of which is one Ton, plus (ii) the Detroit Edison Refined Coal Adder, plus (iii) the MPPA Refined Coal Adder.

* * *

"Resold Coal" means Available Seller Coal sold hereunder to Buyer or to third parties as directed by Buyer.

* * *

"S-Sorb III" is a chemical additive identified in the patents listed in the Amended and Restated License Agreement, dated January 23, 2009, between Chem-Mod LLC and DTE Energy Resources, Inc.

* * *

Section 3.1 Term.

Subject to Section 11.1, the initial term of this Agreement will commence on the Effective Date and will end on the tenth anniversary of the commercial Operations Date. This Agreement shall automatically renew for two additional five-year periods thereafter, unless one Party provides to the other Party written notice of its intent to terminate the Agreement at least 90 days period to the expiration of the then-current Term.

Section 5.1 provides for the production and sale of Refined Coal, and states in part:

Section 5.1. Production and Sale.

(a) During each Contract Year, in accordance with the terms of, and except as otherwise produced in, this Agreement, (i) Buyer shall procure and purchase from Seller all of its requirements for coal and coal-based fuel at the Belle River Power Plant (other than any coal purchased by Buyer under a Back-Up Coal Purchase Contract in accordance with Section 6.1(c)), and (ii) Seller shall use commercially reasonable efforts in accordance with the Operating Protocols, to produce and sell to Buyer Refined Coal in amounts necessary to satisfy Buyer's requirements for coal and coal-based fuel at the Belle River Power Plant….

(b) Buyer's purchase of Refined Coal pursuant to this Section 5.1 shall be reduced to the extent necessary (i) to prevent damage (other than normal wear and tear that would be caused by the exclusive use of coal (other than Refined Coal) as fuel at the Belle River Power Plant) to the boilers, pollution control equipment or other operating components that comprise the Belle River Power Plant that would be caused by the use of Refined Coal as a fuel at the Belle River Power Plant, or (ii) to prevent material impairment to or a material adverse effect on the operation, maintenance, or both, of the boilers, pollution control equipment or other operating components that comprise the Belle River Power Plant or (iii) to prevent the violation of any permit, regulation, or Governmental Approval (any of the foregoing circumstances described in clauses (i), (ii) and (iii) being referred to as a "Reduction Event") and, to the extent that Buyer's requirements are not fully satisfied by Refined Coal, Seller shall sell to Buyer (and Buyer shall purchase) Available Seller Coal, in amounts necessary to satisfy such requirements, as Resold Coal. The determination of a Reduction Event shall be made by Buyer in its good faith discretion….

* * *

(d) During any Reduction Event, as soon as it is reasonably available, Buyer will provide Seller with all information regarding the cause of the Reduction Event and other operating data and other information relating to the use of Refined Coal, and Buyer and Seller will cooperate, discuss and negotiate in good faith to develop and agree upon any price adjustments or other remedial actions to avoid or limit the circumstances leading to the Reduction Event and otherwise to improve, optimize and maximize the use of Refined Coal as a fuel at the Belle River Power Plant on a going-forward basis. Examples of possible remedial actions include, without limitation, capital improvements to the Facility or the Belle River Power Plant, resetting chemical additive levels as provided in Section 8.3(a), and resetting Buyer's requirements for Refined Coal at a quantity less than 100 percent of its coal-based fuel requirements for the Belle River Power Plant. Notwithstanding the foregoing, neither Party shall be required hereunder to agree to any remedial action that would require it to incur additional costs or expenditures. In addition, Seller need not agree to any remedial action (and may terminate any remedial action agreed to) that Seller believes in its sole discretion, could impair or jeopardize the ability of the Refined Coal to qualify for Section 45 Tax Credits.

* * *

(f) Following the Follow-up Period, and subject to resolution of any Reduction Event as may be in effect, Buyer and Seller will cooperate and work together in good faith to optimize and maximize as soon as practicable the use of Refined Coal as a fuel at the Belle River Power Plant.

Sections 5.2, 5.4, and 5.5, also state:

Section 5.2 Sales to Third Parties.

Any Refined coal produced at the Facility and not purchased by Buyer, for any reason, may be sold by Seller to third parties or otherwise disposed of subject to compliance with applicable existing permits, Coal Purchase Contracts and coal transportation agreements, and Buyer's consent, which consent shall not be unreasonably withheld. This Section 5.2 is not intended and shall not be construed to limit any remedies available to Seller hereunder or under applicable Law.

* * *

Section 5.4. Purchase by Buyer at Termination.

On the last day of the Term, to the extent it has not already done so, Buyer shall purchase, and Seller shall sell to Buyer, all Refined Coal on hand.

Section 5.5. Consistent Reporting.

Notwithstanding the means of sourcing fuel for the Belle River Power Plant prior to the Commercial Operations Date, Buyer covenants and agrees that it will not, and it will cause its Affiliates not to, make or give any filing, return, ruling request, representation, allegation, notice or report with or to any Governmental Body or court that contains, or otherwise presents in accounting or financial records, reports or statements, or tax or information returns, characterizations of the transactions (or elements thereof) contemplated by the various Project Documents that are inconsistent with the terms of such Project Documents, such as (buy way of example and not limitation) any characterization that Feedstock purchased by Seller under applicable Coal Purchase Contracts was purchased by Buyer or any other Person, or that Refined Coal sold to Buyer hereunder was something other than Refined Coal.

Section 6.1 of the Agreement states:

Section 6.1. Coal Purchase Contracts.

(a) It is contemplated that Seller, directly or through an Affiliate, will enter into one or more contracts with third-party coal suppliers to purchase coal conforming to the Coal Specifications for use as Feedstock and for sale (as Resold Coal) to Buyer, or others designated by Buyer, as provided herein (each, a "Coal Purchase Contract").

(b) It is further contemplated that included among the Coal Purchase contracts will be purchase contracts that Buyer has in place with coal suppliers on the Commercial Operations Date and that are to be assigned in whole or in part to Seller pursuant to the Coal Inventory Purchase Agreement.

(c) For each Coal Purchase Contract entered into by Seller, Buyer may, but shall not be obligated to, enter into and maintain a back-up Contract to purchase coal from the same third-party coal supplier on terms substantially similar to the terms contained in the corresponding Coal Purchase Contract, including, without limitation, the quantity of coal to be purchased thereunder, except that Buyer's obligation to purchase a quantity of coal thereunder shall be reduced by the quantity of coal purchased by Seller under the corresponding Coal Purchase Contract (each, a "Back-Up Coal Purchase Contract").

(d) Notwithstanding anything to the contrary herein but subject to the provisions of Sections 5.1(e), 8.2(c) and 9.4, Buyer's sole remedies for Seller's failure to produce and sell Refined Coal hereunder shall be to: (i) purchase Resold Coal pursuant to Section 5.1 and to purchase coal under the Back-Up Coal Purchase Contracts; and (ii) terminate this Agreement in accordance with Section 11.1(f).

Section 6.2 states:

Section 6.2. Available Seller Coal.

(a) At any point in time, to the extent that Seller has Available Seller Coal as to which Seller has determined is not needed as Feedstock, Buyer may request to purchase, and upon such request Seller will sell to Buyer, or to others to the extent so directed by Buyer, all (or such portion requested by Buyer) of such Available Seller Coal as Resold Coal at the applicable Resold Coal Price and otherwise as provided herein; provided, however, that, as to any Available Seller Coal that is to be sold to others or shipped for use at a location or facility other than the Belle River Power Plant or St. Clair Power Plant, Seller's obligation to sell such Available Seller Coal shall be subject to receiving Buyer's undertaking to replace or cause to be replaced by arranging for one or more Coal Purchase Contracts for Conforming Coal, and providing for delivery in such a manner that Seller's Feedstock requirements for production of Refined Coal, and its Refined Coal production schedule, and its requirements for Conforming Coal to be sold hereunder as Resold Coal, in each case, will not be impaired.

(b) At any point in time, to the extent that Seller has Available Seller Coal, Seller may request that Buyer purchase all or a portion of such Available Seller Coal, and upon such request, Buyer will purchase and Seller will sell to Buyer, or to others to the extent so directed by Buyer, such Available Seller Coal (or the applicable portion thereof) as Resold Coal at the applicable Resold Coal Price and otherwise as provided herein, it being agreed, for the avoidance of doubt, that Seller's exercise of such right shall not cause to arise an obligation by Buyer to replace Conforming Coal under Section 6.2(a).

Section 6.3. Purchase by Buyer at Termination.

At the end of the Term, Buyer shall purchase, and Seller shall sell to Buyer, all Conforming Coal on hand or under contract as Resold Coal. To the extent that there is any Coal Purchase Contract in place at the end of the Term which, by its terms, obligates Seller to purchase Conforming Coal for a period extending beyond the end of the Term, each Party agrees that Seller will assign such Coal Purchase Contract to Buyer and Buyer will assume Seller's rights and obligations thereunder. 'to the extent not assigned to St. Clair Fuels under the St. Clair Supply Agreement.' To the extent any such Coal Purchase Contract is not able to be so assigned, following the end of the Term, Seller shall sell and Buyer shall purchase Confirming Coal as Resold Coal in accordance with the terms ad conditions hereby until the applicable Coal Purchase Contract expires or otherwise terminates.

Section 7.1 of the Agreement states:

Section 7.1. Deliveries.

(a) Refined Coal deliveries will be made at the Delivery Point for Refined Coal based on Buyer's requirements for use of Refined Coal as fuel in the Belle River Power Plant.

(b) Deliveries of Available Seller Coal will be made at the applicable Delivery Point for Resold Coal as specified herein, and, assuming timely performance by third parties under the Coal Purchase Contracts and by the Coal Consultant under the Coal Handling and Consulting Agreement and except as may be otherwise agreed by the Parties, such deliveries will be made based on Buyer's, or others' to the extent so directed by Buyer, requirements for use of Available Seller Coal as fuel.

Section 7.5 of the Agreement states:

Section 7.5. Title and Risk of Loss.

(a) Title and risk of loss, damage or destruction with respect to the Refined Coal sold hereunder will pass to Buyer at the Delivery Point for Refined Coal.

(b) Title and risk of loss, damage or destruction with respect to the Resold Coal sold hereunder will pass to Buyer at the applicable Delivery Point for Resold Coal.

Section 8.2(a) of the Agreement states:

(a) Refined Coal produced and sold to Buyer hereunder shall be produced from Feedstock that was purchased pursuant to a Coal Purchase Contract and was conforming Coal at the time delivered to the Belle River Site.

Section 8.3, entitled "Chemical Additives," states in Section 8.3(b) and 8.3(c) as follows:

(b) Upon Buyer's request, Seller shall for a period of up to seven days of testing, supply additional Mer-Sorb, at its own expense, and increase the application rate for Mer-Sorb to the level that the Parties mutually agree is likely [to] reduce the mercury emissions from the Belle River Power Plant to the maximum level of mercury emissions reductions that can be reasonably achieved by the application of additional Mer-Sorb to the Conforming Coal (all subject to the physical constraints of the Facility); provided, however, that all costs and expenses (other than the cost of such additional Mer-Sorb) related to such testing shall be borne by Buyer.

(c) During any time during the Term that the Facility is not operating, Buyer shall have the right to purchase from Seller, as Seller's delivered cost, such chemical additives for use at the Belle River Power Plant; provided that Buyer shall be responsible for any capital relating to the handling, storage and use of such chemical additives so purchased, including with limitation, any capital costs associated with or required for Buyer's use of such chemical.

Sections 8.4 and 8.5 of the Agreement, state:

Section 8.4. <u>Presumption Regarding Conforming Coal and Refined Coal</u>.

BUYER AGREES THAT ANY RESOLD COAL OR FEEDSTOCK WILL BE CONCLUSIVELY PRESUMED TO HAVE BEEN CONFORMING COAL IF SUCH COAL WAS PURCHASED BY SELLER PURSUANT TO THE COLLECTIVE COAL INVENTORY PURCHASE AGREEMENTS OR: (A) WAS PURCHASED BY SELLER PURSUANT TO A COAL PURCHASE CONTRACT THAT WAS ASSIGNED TO SELLER BY BUYER OR THAT WAS CERTIFIED BY THE COAL CONSULTANT AS PROVIDED IN THE COAL HANDLING AND CONSULTING AGREEMENT, AND (B) WAS NOT RECOMMENDED FOR REJECTION IN ACCORDANCE WITH THE

APPLICABLE COAL PURCHASE CONTRACT BY THE COAL CONSULTANT PURSUANT TO THE COAL HANDLING AND CONSULTING AGREEMENT, AND WAS PREPARED, BLENDED AND DELIVERED TO THE APPLICABLE DELIVERY POINT BY THE COAL CONSULTANT PURSUANT TO THE COAL HANDLING AND CONSULTING AGREEMENT. ACCORDINGLY, BUYER WAIVES ANY RIGHT IT MIGHT HAVE TO REJECT OR TO REVOKE ACCEPTANCE OF, OR TO CLAIM DAMAGES OR ANY OTHER RELIEF WITH RESPECT TO ANY SUCH RESOLD COAL OR ANY REFINED COAL PRODUCED FORM SUCH FEEDSTOCK BY REASON THAT SUCH RESOLD COAL OR FEEDSTOCK WAS NOT CONFORMING COAL.

Section 8.5. Warranty Disclaimer.

(a) EXCEPT AS EXPRESSLY PROVIDED IN THIS ARTICLE VIII, ALL RESOLD COAL AND REFINED COAL SOLD PURSUANT TO THIS AGREEMENT IS SOLD "AS IS" AT THE APPLICABLE DELIVER POINT PROVIDED HEREIN.

(b) EXCEPT AS EXPRESSLY PROVIDED IN THIS ARTICLE VIII, SELLER HEREBY DISCLAIMS ALL WARRANTIES (OTHER THAN THE WARRANTY OF TITLE) WHETHER EXPRESS OR IMPLIED, INCLUDING, WITHOUT LIMITATION, IMPLIED WARRANTIES OF MERCHANTABILITY AND FITNESS FOR A PARTICULAR PURPOSE AND ALL WARRANTIES REGARDING THE COMPATIBILITY OF ANY REFINED COAL WITH ANY BUYER EQUIPMENT.

Sections 9.3 and 9.4, in relevant part, state:

Section 9.3. Coal Consultant Fee Reimbursement.

Buyer shall reimburse Seller for the Coal Fee as and when paid under the Coal Handling and Consulting Agreement.

Section 9.4. O&M and Capital Cost Reimbursement.

(a) Seller shall reimburse Buyer for increased operation and maintenance expenses incurred and that Buyer demonstrates are related to Buyer's use of Refined Coal (and not increased levels of chemical additives pursuant to Section 8.3) as a fuel in the Belle River Power Plant that would not have been incurred from use of coal (other than Refined Coal), but only to the extent such costs are not included in the calculation of Detroit Edison Benefits ("Increased Expenses"). . . . .

Section 9.5 sates in relevant part as follows:

Section 9.5. Invoicing and Payment.

> (a) Buyer shall pay Seller by electronic transfer (recipient's account per Seller's advice) in United States funds for all Refined Coal produced and sold by Seller and purchased by Buyer hereunder…. From time to time, Seller, with assistance of the Coal Consultant, shall determine (i) the actual Refined Coal Price, (ii) the actual price of the Detroit Edison Refined Coal Adder, and (iii) the actual price of the MPPA Refined Coal Adder, in each case, applicable to the Refined Coal produced and sold during the most recent period following any prior true-up adjustment and any resulting true-up adjustment will be reflected (as an addition or reduction, as the case may be) on the monthly invoice next submitted by Seller hereunder….
>
> (b) Buyer shall pay Seller by electronic transfer (recipient's account per Seller's advice) in United States funds for all Resold Coal from the Feedstock Inventory Store purchased and sold hereunder…. From time to time, Seller, with assistance of the Coal Consultant, shall determine the actual Resold coal Price applicable to the Resold Coal from the Feedstock Inventory Store delivered to Buyer hereunder during the most recent period following any prior true-up adjustment and any resulting true-up adjustment will be reflected (as an addition or reduction, as the case may be) on the monthly invoice next submitted by Seller hereunder….
>
> (c) Buyer shall pay Seller by electronic transfer (recipient's account per Seller's advice) in United States funds for all Resold Coal purchased and sold hereunder other than from the Feedstock Inventory Store….
>
> (d) Buyer shall pay Seller by electronic transfer (recipient's account per Seller's advice) in United States funds for the reimbursement required under <u>Section 9.3</u>. Seller shall submit to Buyer an invoice for the Coal Fee during each month….

Section 11.1 entitled "Early Termination" provides several grounds for early termination of the Agreement, including subparagraphs (d) and (h) which state:

> (d) Upon the date specified in a notice of termination from Seller to Buyer, so long as such date follows the expiration of 30 days' notice, if a change in Law or circumstances that results in a material increase in costs and expenses or a material reduction in revenue or benefits in respect of Section 45 Tax Credits; <u>provided</u> that to the extent Seller terminates in accordance with this <u>Section 11.1(d)</u>, Seller shall not be required to produce and sell Refined coal pursuant to <u>Section 5.1</u> from the date of the notice of termination until the effective date of such termination;
>
> (h) Upon the date specified in a notice of termination from Buyer to Seller, so long as such date follows the expiration of 30 days' notice, if an order issued by the Michigan Public Service Commission, or a change in Law, related to Buyer's use of Refined Coal as a fuel in the Belle River Power Plant, this

Agreement or any of the transactions contemplated by the Project Documents results in an increase in costs and expenses or a reduction in revenue to Buyer; or

* * *

Section 12.2, Entitled "Remedies" states in sub-paragraph (d) as follows:

(d) Notwithstanding any other provision of this Agreement to the contrary, the remedies contained in this Article XII shall not be applicable to any matter governed by the Environmental Law or pertaining to Hazardous Materials, as those terms are defined in the Environmental Indemnity Agreement, and the Parties acknowledge and agree that any indemnification or other remedies as to such environmental matters are governed solely and exclusively by the Environmental Indemnity Agreement.

Sections 14.2, 14.3, and 14.4 deal with provisions applicable to "Confidentiality," "Required Disclosure," and "Compliance with Laws and Governmental Approvals." Section 14.9 also provides:

Section 14.9. Limitations of Liability and Exclusive Remedies.

(a) NEITHER PARTY NOR ITS AFFILIATES SHALL BE LIABLE UNDER THIS AGREEMENT TO THE OTHER PARTY OR ITS AFFILIATES FOR CONSEQUENTIAL OR INDIRECT LOSS OR DAMAGE, INCLUDING, WITHOUT LIMITATION, LOSS OF PROFIT, LOSS OF TAX BENEFIT OR CREDITS, LOSS OF GOODWILL OR ANY OTHER SPECIAL, PUNITIVE OR INCIDENTAL DAMAGES RESULTING FORM ANY VIOLATION OF OR DEFAULT UNDER THIS AGREEMENT.

(b) THE PROVISIONS OF THIS SECTION 14.9 SHALL APPLY TO ALL CLAIMS BASED ON OR ARISING UNDER THIS AGREEMENT, WHETHER IN CONTRACT, EQUITY, TORT OR OTHERWISE, REGARDLESS OF FAULT, GROSS OR OTHER NEGLIGENCE (IN WHOLE OR IN PART), STRICT LIABILITY, BREACH OF CONTRACT OR BREACH OF WARRANTY AND SHALL EXTEND TO THE MEMBERS, MANAGERS, TRUSTEES, DIRECTORS, OFFICERS AND EMPLOYEES, AGENTS AND RELATED PERSONS OR AFFILIATES OF EACH PARTY, AND THEIR RESPECTIVE MEMBERS, MANAGERS, DIRECTORS, TRUSTEES, OFFICERS, EMPLOYEES AND AGENTS.

Exhibit E to the Agreement (Exhibit A-30, page 69 of 806), entitled "Operating Protocols," states:

Description of the Process

Refined Coal will be produced in the Facility by mixing two proprietary reagents - a dry, solid reagent called S-Sorb III and a liquid solution called Mer-Sorb -- with Conforming Coal. S-Sorb III and Mer-Sorb will be added proportionally to the Conforming Coal in pug mill mixers in the Facility. The pug mills will thoroughly mix the reagents with the Conforming Coal to create Refined Coal. The Refined Coal will then be delivered directly to the Belle River Power Plant for combustion.

Reagent Application Rates

S-Sorb III and Mer-Sorb[1] will be mixed with the Conforming Coal at the following application rates:

Chemical Regent	Min Application Rate per Ton of Coal	Max Application Rate per Ton of Coal
S-Sorb III	% (redacted)	% (redacted)
Mer-Sorb	% (redacted)	% (redacted)

Beginning in the year that Buyer is required by Law to reduce mercury emissions from the Belle River Power Plant, Seller shall, at its own expense, increase the application rate for Mer-Sorb to the level that the Parties mutually agree will reduce the mercury emissions from the Belle River Power Plant to the lower of (i) the level required by Law, or (ii) the maximum level of mercury emissions reductions that can be reasonably achieved by the application of additional Mer-Sorb to the Conforming Coal.

Production Level

The Facility will operate pursuant to the fueling schedule for the Belle River Power Plant.

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[1] S-Sorb III and Mer-Sorb are the chemical additives identified in the Patents listed in the Amended and Restated License Agreement, dated January 23, 2009, between Chem-Mod LLC and DTE Energy Resources, Inc.

A February 15, 2011 Letter Agreement (Appendix A-30, pp 81-84) between the Belle River Fuels Company, LLC and the Detroit Edison Company, states in relevant part:

This letter is in reference to that certain Refined Coal Supply Agreement, dated December 4, 2009, as amended by an Amendment, dated as of March 1, 2010 (the “Agreement”), between Belle River Fuels Company, LLC and The Detroit Edison Company.

* * *

The Parties agree that notwithstanding anything to the contrary in the Agreement, that any time prior to BR Fuels purchase of Coal Inventory pursuant to the Coal Inventory Purchase Agreement that BR Fuels is not producing Refined Coal from the Facility that BR Fuels shall not be required to provide Detroit Edison Resold Coal and Detroit Edison shall be permitted to procure coal from sources other than BR Fuels to fuel the Belle River Power Plant.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **THE DETROIT EDISON COMPANY** for Reconciliation of its Power Supply Cost Recovery Plan for the 12-Month Period Ending December 31, 2011 ______________________________________/	Case No. **U-16434-R** (Paperless e-mail)

ELECTRONIC SERVICE LIST

On the date below, an electronic copy of the **Initial Brief of the Michigan Community Action Agency Association** was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

Respectfully submitted,

Don L. Keskey

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Date: April 30, 2013