The Detroit Edison Company
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Detroit Edison
A DTE Energy Company

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September 30, 2010

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
6545 Mercantile Way, Suite 15
Lansing, Michigan 48909

Re: In the matter of the Application of The Detroit Edison Company for Authority to Implement a Power Supply Cost Recovery Plan In Its Rate Schedules for 2011 Metered Jurisdictional Sales of Electricity
MPSC Case No. U-16434 (Paperless e-file)

Dear Ms. Kunkle:

Attached for electronic filing is The Detroit Edison Company's 2011 PSCR Plan Application, and Testimony and Exhibits of Mses. Sherrie L. Siefman and Angela P. Wojtowicz and Messrs. Robert A. Gailliez, Michael G. Hoffman, Kenneth D. Johnston, and Michael W. Shields and Testimony of Mr. James J. Musial in the above-referenced case. Also attached is a Proof of Service.

Very truly yours,

David S. Maquera

Digitally signed by David S. Maquera
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David S. Maquera

DMS / jmb
Attachments
cc: Service List
Jon P. Christinidis

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of THE DETROIT EDISON COMPANY for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules For 2011 Metered Jurisdictional Sales Of Electricity.	)))))))	Case No. U-16434

2011 PSCR PLAN APPLICATION OF
THE DETROIT EDISON COMPANY

The Detroit Edison Company ("Applicant," the "Company," or "Detroit Edison"), a subsidiary of DTE Energy and a corporation organized and existing under and by virtue of the laws of the State of Michigan, with its principal office at One Energy Plaza, Detroit, Michigan 48226, hereby files this Application requesting authority from the Michigan Public Service Commission ("Commission" or "MPSC") to implement, in accordance with 1982 PA 304, MCL 460.6j *et seq*. ("Act 304"); 2000 PA 141, MCL 460.10 *et seq*. ("Act 141"); 2008 PA 295, MCL 460.1001 *et seq.* ("Act 295"); R 460.17101 *et seq*.; and relevant Commission orders, a Power Supply Cost Recovery ("PSCR") plan in its rate schedules for 2011 metered jurisdictional sales of electricity. In support thereof, Applicant states as follows:

1. Applicant is an investor-owned Michigan corporation supplying retail electric service to customers located in Southeast Michigan and is a public utility subject to the jurisdiction of the Commission.

2. Applicant no longer owns or operates an electric transmission system, but instead purchases transmission service from International Transmission Company ("ITC"), an unaffiliated transmission provider, in association with the Midwest Independent System Operator ("MISO"). Transmission and MISO costs have been approved by the Commission for recovery

through the PSCR process in Detroit Edison Case Nos. U-13808, U-13808-R, U-14275, U-14275-R, U-14702, U-14702-R, U-15002, U-15002-R, U-15417, U-15417-R and U-16047 spanning the PSCR years 2004, 2005, 2006, 2007, 2008, 2009 and 2010. *See also,* November 23, 2004 Opinion and Order in Case No. U-13808 (pp 67, 112), *aff'd in relevant part, In re Application of Detroit Edison Co,* 276 Mich App 216, 229; 740 NW2d 685 (2007), *aff'd in relevant part*, 483 Mich 993 (2009). *See also, Attorney General v Public Service Commission,* unpublished opinion per curiam of the Court of Appeals, decided August 2, 2007 (Docket No. 265869); *Michigan Environmental Council* v *Public Service Comm*, unpublished opinion per curiam of the Court of Appeals, decided May 11, 2004 (Docket Nos. 244354 and 246744), *lv den* 471 Mich 870 (2004) (Slip Op at p 6) (all permitting and affirming the recovery of transmission expenses through the PSCR process).

3. Applicant is presently serving its jurisdictional metered and unmetered electric customers under rates and charges approved by this Commission.

4. On October 13, 1982, PA 304 was signed into law. In conformity with 1982 PA 304, the Commission, in MPSC Case No. U-7510, approved a PSCR clause for use by the Company. This clause provides for, among other things, an annual filing of a PSCR plan and development of PSCR factors to be applied to customers' bills during the period covered by the plan. Act 141, through MCL 460.10d, provided for, among other things, a rate freeze period commencing in 2000 and ending on December 31, 2003 with a period of continuing rate caps terminating December 31, 2005. On December 18, 2003, the Commission issued an order reinstating Detroit Edison's PSCR clause effective January 1, 2004. (MPSC Case No. U-13808 Order dated December 18, 2003, p 11).

5. In Case No. U-15002, the Commission issued a December 21, 2006 Order granting Detroit Edison's motion for approval to roll its projected 2006 PSCR underrecovery into its 2007 PSCR factors, and also granting continuing authority to roll prior-year under and overrecoveries into its future PSCR plans. At the time of this filing, Detroit Edison projects that it will have a PSCR under-recovery for the 2010 PSCR period amounting to $36.349 million. The Company increased its PSCR factor on a bills-rendered basis for all customers effective July 1, 2010 in an effort to minimize the under-collection projected at that time for the 2010 PSCR period. It is important to note that this projection could change based upon actual results for the balance of the 2010 PSCR Plan period and/or the final order in the Company's 2009 PSCR Reconciliation Case No. U-15677-R.

6. Applicant is hereby filing its 2011 PSCR Plan in this docket and is seeking Commission approval to include a PSCR Factor of (2.98) mills per kWh (i.e., negative 2.98 mills per kWh) in customers' bills for the period January 1, 2011 through December 31, 2011. The levelized PSCR Factor for which Applicant is seeking approval is based upon the Company's 2011 PSCR Plan. This Factor represents the amount by which the Company's projected fuel and purchased power expense, including transmission, MISO and other costs, are projected to be lower than the Company's existing PSCR base of 31.26 mills per kWh during the 2011 PSCR Plan year.[1] This Factor will be applied to all PSCR customers.

7. Nitrogen Oxide ("NO_x") and Sulfur Dioxide ("SO_2") emission allowance expenses are also included in the Company's calculation of its 2011 PSCR Factor. NO_x and SO_2 emission allowance expenses have been previously approved by the Commission for recovery through the PSCR process. (See, for example, Case No. U-13808 Order dated November 23,

[1] The PSCR base is that approved in the December 23, 2008 and January 13, 2009 Orders in MPSC Case No. U-15244.

2004, p 112; Case No. U-14702 Order dated September 26, 2006, p 5; Case No. U-15244 Order dated January 13, 2009 approving rate sheets for new PSCR base). Detroit Edison has determined that the best emission reduction strategy to comply with federal and state air quality regulations is to utilize a cost-effective combination of installed emission-reduction technologies on a number of its generating units, and otherwise manage the economic and compliance risk by purchasing necessary emission allowances. The overall goal of the Company's plan is to achieve full compliance at a reasonable cost consistent with reliability and other factors. For purposes of providing a complete 5-year power supply forecast, the Company is also providing an estimate of the mercury emission-related expense for 2015, which is the first compliance year for Michigan Rule 1503 (R 336.2503 Mercury Emission Standards for Electric Generating Units). As discussed in the testimony of Company witnesses Johnston and Wojtowicz, the Company expects to use activated carbon to address these Mercury (Hg) reduction requirements at several of its power plants and expects to request recovery of the sorbents used in this process through the PSCR, similar to urea expense. Pursuant to MCL 460.6j(7), the Company is seeking the Commission's concurrence that it is likely to permit the Company to recover the mercury emission-related expense for 2015.

8. In Case No. U-14838, the Commission approved the Choice Incentive Mechanism ("CIM"), which is intended to moderate certain impacts of the Electric Choice program on the financial health of Detroit Edison. (Case No. U-14838 Order Approving Settlement dated August 31, 2006, p 4, Settlement Agreement, pp 4-7). Detroit Edison does not anticipate the CIM becoming an issue in this 2011 PSCR Plan proceeding.

9. Also included in Applicant's filing is a five-year forecast of the power supply requirements of its customers, anticipated sources of supply, and projections for power supply

costs, including the cost of transmission service needed to transmit electric capacity and energy to the Applicant's distribution system in Southeast Michigan.

10. The details of Applicant's PSCR Plan, PSCR Factor and five-year PSCR forecast are set forth in the testimony and exhibits of the Company's witnesses Messrs. Gailliez, Hoffman, Johnston, Musial, and Shields, along with Ms. Siefman and Wojtowicz, which are being filed contemporaneously with this Application.

11. The Company continues to evaluate a coal refinement technology (a/k/a Reduced Emission Fuel or "REF") being developed by DTE Energy Services that promises to reduce NOx, SO_2 and Hg stack emissions at coal-fired power plants. The subject coal refinement process is designed to reduce these coal-fired electric generation plant stack emissions and result in emissions reduction benefits to electric utilities such as Detroit Edison. The Company has not made a commitment to move forward with the implementation of this alternative for the 2011 PSCR Plan year but is supporting the proposed methodology should it make a decision to do so. The Company's Mr. Johnston discusses the potential for implementing DTE Energy Services' REF process in the 2011 PSCR Plan year. Regardless of the Company's decision to move forward with REF in 2011, that decision will have no impact on the Company's requested maximum PSCR factor for 2011.

12. In addition to the environmental benefits of the emission reductions, DTE Energy Services' REF process is expected to reduce the need for NOx and SO_2 emission allowances, the cost of which are recovered in Detroit Edison's PSCR process. Mercury emissions become regulated emissions in 2015, and the expense for reducing Hg emissions would also likely be reduced through REF. In effect, the cost of coal refinement under the DTE Energy Services' REF process would be a cost of fuel burned for electric generation, would be an integral part of

prudent fuel procurement and utilization, would constitute a disposal cost of fuel, and therefore would be properly recovered in Detroit Edison's PSCR process for the same reasons, explained infra, that Urea should be recovered in the Company's PSCR process, as there would be a direct trade off between the use of REF and Detroit Edison's consumption of NOx and SO_2 emission allowances.

13. Applicant is also requesting ongoing Commission authority to include the incremental costs of urea above or below the amount in Detroit Edison's base rates for recovery in the Detroit Edison PSCR process. Urea is a chemical agent utilized at the Company's Monroe Power Plant in the selective catalytic reduction ("SCR") units to reduce NOx emissions and thus reduce the need for NOx emission allowances, the cost of which is already approved for recovery in Detroit Edison's PSCR process. As explained in greater detail in the testimony of Ms. Wojtowicz and Messrs. Johnston and Hoffman, there is a direct trade off between the consumption of urea in the SCR units and the consumption of NOx emission allowances. In effect, urea is a cost of fuel burned for electric generation, is an integral part of prudent fuel procurement and utilization, and would constitute a disposal cost of fuel, and therefore should be recovered in Detroit Edison's PSCR process. The Commission has already approved the inclusion of chemical additives used to reduce emissions for recovery in the PSCR process of another Michigan electric utility. (See Case No. U-15352, Order dated December 4, 2007, Exhibit A, Settlement Agreement, Paragraph 8 g., p.3).

14. The Commission has also concluded that urea is a "disposal" cost in the November 13, 2008 Order in Consumer Energy's 2008 PSCR Plan Case No. U-15415. MCL 460.6j(1)(a) clearly entitles:

> “…the utility to recover the booked costs, including transportation costs, reclamation costs, and disposal and processing costs, of fuel burned by the utility for electric generation..”

Not consuming urea in the SCRs would result in the consumption of additional NOx emission allowances at a cost per ton that is significantly higher than that of urea. Thus, the Commission supported inclusion of urea expense in the PSCR process when it stated:

> “Just as there is a direct connection between the quantity and type of fuel burned and the need to purchase emissions allowances there is also a direct connection between fuel burned, emissions, and urea expense. Allowing the recovery of urea expense as a disposal cost of the fuel burned by the utility is consistent with the language of MCL 460.6j(1)(a).” (MPSC Case No. U-15415, Order dated November 13, 2008, pp. 11- 12)

Therefore, it is reasonable, prudent and lawful to include incremental (or total costs if subsequently requested by Detroit Edison) urea expenses for recovery in Detroit Edison’s power supply cost recovery process and the Company requests that the Commission approve such treatment of urea expense in this and future Detroit Edison power supply cost recovery cases.

WHEREFORE, Applicant requests that this Commission:

A. Accept for filing this Application for authority to implement its PSCR Plan in its rate schedules for 2011 metered jurisdictional sales of electricity.

B. Give such notice to interested parties as may be required by statute or the Commission's rules.

C. Set an early date for hearing on said Application.

D. Approve Applicant’s request for recovery of the incremental costs (or total costs if subsequently requested by Detroit Edison) of urea above or below the amount of urea costs in Detroit Edison’s base rates, in the Company’s PSCR process.

E. Enter its Order, pursuant to MCL 460.6j(7), providing concurrence from the Commission that it is likely to permit the Company to recover the mercury emission-related expense for 2015.

F. Enter its Order approving the implementation of Applicant's proposed PSCR Plan and Factor in Applicant's rates for 2011 metered jurisdictional sales of electricity, and otherwise expedite approval of Applicant's request for a levelized 2011 PSCR Factor of (2.98) mills per kWh (i.e., negative 2.98 mills/kWh) in customers' bills for the period January 1, 2011 through December 31, 2011, inclusive of Detroit Edison's projection of a PSCR under-recovery for the 2010 PSCR period amounting to $36.349 million, which could change based upon actual results for the balance of the 2010 PSCR Plan period and/or the final order in its 2009 PSCR Reconciliation Case No. U-15677-R.

G. Enter its Order approving Applicant's 5-year PSCR forecast.

H. Enter its Order approving the Transfer Price treatment of renewable energy in Detroit Edison's PSCR process as proposed, described and explained in this Application and the Company's Testimony and Exhibits.

I. Grant Applicant such further additional relief and authority as the Commission may deem necessary, suitable and appropriate.

THE DETROIT EDISON COMPANY

Dated: September 30, 2010

By: David S. Maquera

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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
THE DETROIT EDISON COMPANY	)	
for Authority to Implement a Power	)	Case No. U-16434
Supply Cost Recovery Plan in its	)	
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Jurisdictional Sales of Electricity	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ROBERT A. GAILLIEZ

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF ROBERT A. GAILLIEZ

Line No.

Q. What is your name, business address and who are you testifying on behalf of?

A. My name is Robert A. Gailliez. My business address is: 6400 N. Dixie Hwy., Newport, MI 48166. I am testifying on behalf of The Detroit Edison Company ("Company" or "Detroit Edison").

Q. What is your present position with the Company?

A. My title is Supervisor – Reactor Engineering.

Q. Briefly describe your responsibilities in this position.

A. I am responsible for the group that performs Fermi 2 core design, reactor operation, administration of fuel fabrication, uranium, and enrichment services contracts, and fuel economics.

Q. Please summarize your educational and professional qualifications.

A. I received a Bachelor of Science Degree in Nuclear Engineering from the University of Cincinnati in 1982. In addition, I have completed many technical courses on subjects such as Boiling Water Reactor operation. I am qualified as a Station Nuclear Engineer at Fermi 2 and have been certified as a Shift Technical Advisor.

Q. Please briefly describe your professional experience.

A. Upon receiving my Bachelor of Science degree from the University of Cincinnati, I spent two years as a training instructor at the Davis Besse Nuclear Power Plant. I have been with The Detroit Edison Company (Detroit

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Edison or Company) since 1984. At Detroit Edison's Fermi 2 Power Plant, I have served in a variety of staff engineer and management positions. The positions include: Senior Training Instructor, Shift Technical Advisor; Supervisor - Shift Technical Advisors, Work Week Manager, Principal Engineer - Probabilistic Safety Assessment, and Supervisor – Reactor Engineering. Since 2001, I have been the Supervisor – Reactor Engineering.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission?

A. Yes. I sponsored testimony in the following cases:

U-15417	2008 Power Supply Cost Recovery Plan
U-15677	2009 Power Supply Cost Recovery Plan
U-16047	2010 Power Supply Cost Recovery Plan

Line No.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support the five-year projection of Detroit Edison's Fermi 2 nuclear fuel expense presented principally in Exhibit A-1.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-1	Nuclear Fuel Expense Forecast

Q. Was this exhibit prepared by you or under your direction?

A. Yes.

Q. What are the basic steps associated with the nuclear fuel cycle?

A. The nuclear fuel cycle consists of the following eight basic steps:

1. Mining and Milling — Natural uranium is obtained from the exploration and mining of uranium ore. Underground, open-pit and in-situ leaching techniques are typically used, and are similar to those used in other low-grade ore mining operations. Uranium ore obtained from U.S. mines average only a few pounds of uranium per ton of ore – with a typical grade between 0.1 to 0.3%. Some uranium mines in Canada have relatively higher ore grades (such as between 0.4 to 11%).

   Milling is the mechanical and chemical process of extracting uranium from the mined ore in the form of U3O8 concentrate, frequently called yellowcake. Yellowcake is the form of natural uranium most commonly

Line No.

traded.

2. Conversion — In the conversion process, the U3O8 is purified and chemically converted into uranium hexafluoride (UF6). The UF6 is a gaseous compound of uranium and fluorine used as feed in the enrichment process. The unit costs of conversion services are typically expressed in dollars per kilogram of uranium as UF6. The amount of uranium lost in process during the conversion process is about 0.5%.

3. Enrichment Services — Natural (unenriched) uranium contains approximately 0.7% of the fissile isotope U235, and 99.3% of the fertile isotope U238. Light water reactors are typically designed to utilize enriched uranium having an average U235 content of 3% to 4%. In the United States, uranium for commercial nuclear power plants is enriched in gaseous diffusion plants operated by the United States Enrichment Corporation (USEC). In Europe, enrichment services are by gaseous diffusion process or centrifuge methods.

In the diffusion process or centrifuge method, the effort required to separate a given amount of natural uranium (feed) into enriched uranium (product) and depleted uranium (tails) is expressed in separative work units (SWU).

4. Design and Licensing — Prior to fabrication of fuel assemblies, the

Line No.

fuel must be designed and licensed to operate in a specific core. The fuel fabrication vendors are required to assure that the fuel will operate safely before fabricated fuel can be loaded into a nuclear reactor.

5. Fabrication — In the fabrication plant, the enriched uranium hexafluoride (UF6) is chemically converted to uranium dioxide powder (UO2). The powder is pressed and sintered into hard ceramic fuel pellets that are loaded into long, narrow zirconium tubes. After sealing, the tubes (fuel rods) are assembled into fuel bundles using spacers and end fittings to hold the fuel rods together. The Fermi 2 reactor core requires 764 fuel bundles.

6. Heat Generation — During reactor operation, heat is produced inside the fuel rods by the fission of U235. In the case of Fermi 2, the heat is absorbed by cooling water which turns to steam in the reactor. The steam passes through a turbine-generator to produce electrical energy. The heat generating process is initiated by the partial removal of the control rods from the core.

Throughout an operating cycle, the control rods must be progressively withdrawn as U235 is consumed. The end of an operating cycle typically occurs when the control rods are fully withdrawn, and the reactor is no longer able to maintain rated power. At this point, the reactor is shut down for refueling during which approximately one-

Line No.

quarter to one-third of the fuel bundles are removed from the core and replaced with new fuel bundles. The normal in-core life of a fuel bundle is approximately four cycles, during which time the total front end cost of the bundle is completely amortized on the basis of heat generated.

7. Spent Fuel Storage and Cooling — After removal from the reactor, spent fuel bundles are stored underwater in an on-site fuel pool while heat generated by the radioactive decay of the fission products is reduced to a level suitable to allow off-site shipment.

8. Disposal — The Nuclear Waste Policy Act of 1982 has assigned to the U.S. Department of Energy ("DOE") Office of Civilian Radioactive Waste Management the responsibility of building and placing into operation a permanent geologic repository for commercially generated Spent Nuclear Fuel ("SNF"). The DOE has stated that it will accept SNF for permanent geologic storage. While the DOE prepares for receipt of SNF, SNF will be stored on-site in the spent fuel pool and in an onsite dry cask storage facility.

Q. Who at Detroit Edison is responsible for managing the nuclear fuel contracts?

A. Contracts for uranium, conversion, enrichment, fabrication and the DOE spent fuel contract are managed by Nuclear Supply Chain personnel with assistance from the Reactor Engineering personnel.

Line No.

Q. What is the current status of Detroit Edison's uranium contracts?

A. Detroit Edison has variable commitments which cover 100% of the Company's uranium ore and conversion requirements through Cycle 20. The plant was refueled in April 2009 and Detroit Edison is currently in Cycle 14. The plant's next refueling is scheduled for October 2010 after which time Fermi 2 will be in Cycle 15.

Q. What is the current status of the fabrication contract?

A. The original nuclear fuel contract with General Electric was negotiated in 1971, and included the fabrication of the first core of 764 bundles and the first reload of fuel. The current fabrication contract with General Electric, for Cycles 3 through 8, was negotiated in 1989, and amended in 1991. The contract was amended again in 1997 to extend the commitment through Cycle 11 and again in 2003 to extend the commitment through Cycle 14. After Cycle 14, the current fabrication contract will apply through at least Cycle 15 and 16 fuel purchases.

Q. What is the status of Detroit Edison's enrichment contract?

A. Detroit Edison has variable commitments which cover 100% of our enrichment requirements through Cycle 19, and options to extend our current contracts to cover subsequent fuel loads.

Q. What are the components of nuclear fuel expense?

A. There are three basic components of nuclear fuel expense: (1) front end costs, (2) in-core interest expense, and (3) regulatory costs. Front end

Line No.

costs are the sum of the ore, conversion, enrichment services, and fabrication costs for the fuel and are amortized to PSCR expense over the life of the fuel. In-core interest expense represents the periodic in-core interest payments made on the unamortized value of the in-core fuel. Currently, Detroit Edison owns the nuclear fuel so no interest expense is being charged to PSCR expense. However, Detroit Edison does incur expenses related to the cost of money needed to own the fuel, and these are currently included in Base Rates.

Regulatory costs are fees paid to governmental agencies relative to nuclear fuel. The current regulatory cost is the SNF disposal cost of $1/MWh of net electrical generation sold. Title 10, Part 961, Appendix G of the Code of Federal Regulations states that the utility will pay a fee based on $1.00 per net MWh sold. Detroit Edison does not pay $1.00 per MWh for each net MWh generated by Fermi 2. The Fermi 2 energy furnished without charge, energy used by the Company, transmission losses, and distribution losses are excluded from total generation to establish the net MWh sold. Detroit Edison has no discretion over the payment of regulatory costs.

Q. How is the payment to the federal government for fuel disposal of $1.00/net MWh sold used to cover expenses associated with federal receipt and disposal of SNF?

A. Detroit Edison considers the $1.00/net MWh sold to be compensation to the DOE for executing its responsibilities and obligations in accordance with the standard contract for disposal of SNF and Title 10, Part 961 Appendix G.

Line No.

Under the contract and law, the primary responsibility of the DOE is to accept title to the SNF and provide for its transportation from Fermi 2 to the disposal site. In this regard, the DOE is responsible for providing the shipping cask and its handling procedures, any special tools or equipment necessary to handle the cask, and routine cask maintenance.

The DOE is not responsible for the preparation and packaging of the SNF, or for the loading of the shipping cask. Additionally, the DOE is not responsible for any incidental maintenance, protection, or preservation of the cask while it is in the possession and control of Detroit Edison. The fees paid by Detroit Edison to the DOE are deposited into the Nuclear Waste Fund, as required by Public Law 97-425, and the fee may be adjusted from time to time in accordance with the law to ensure full cost recovery by the DOE.

NUCLEAR FUEL EXPENSES

Q. What nuclear fuel expense is projected for the years 2011 through 2015?

A. Exhibit A-1 provides the projection of Fermi 2 net electric generation and nuclear fuel expense for the specified years.

Q. Has Detroit Edison purchased UF6 in addition to its immediate requirements?

A. Yes. Detroit Edison’s Uranium supplier has a uranium mine out of service. The supplier anticipates a reduction in UF6 output. In response, Detroit

Line No.

Edison made a UF6 spot purchase in 2007 to assist in covering a small projected UF6 shortfall. This small shortfall and spot purchase was made to ensure continuity of UF6 supply and hence continuous operation of Fermi 2 as a base loaded generation facility.

Q. How are the fuel cost projections at Fermi 2 created?

A. The Fermi 2 fuel cost projections provide the Nuclear Generation Organization with the budget for fuel amortization and the expected net nuclear generation targeted to achieve the plant goals. The fuel cost projection is based on a set of assumptions on how Fermi 2 will operate in the ensuing years.

Q. What do the nuclear fuel expenses shown on Exhibit A-1 represent?

A. These are fuel expenses directly tied to projected generation from Fermi 2. Exhibit A-1 has been prepared to present these expenses on a per unit basis. Fermi 2 fuel expenses are directly dependent upon expected generation targets. Target generation, per unit fuel expense and total fuel expense through 2015 are depicted on Exhibit A-1. The generation targets as depicted by column “B” account for planned and unplanned losses in generation.

The planned losses in generation include refueling outages as well as scheduled power reductions in support of required surveillances and necessary core management activities. Additionally, a reasonable amount of unplanned losses in generation are assumed. The combination of unplanned and planned losses in generation is discounted from the Fermi 2 expected demonstrated capability. It is these generation targets that are used to anticipate the Fermi 2 fuel expenses as depicted by Exhibit A-1. The generation targets are used to determine the expected energy requirement for the fuel cycle.

The purchase of ore, conversion services, enrichment services and fabrication for the fuel necessary to support the energy requirement is then amortized over a specified number of fuel cycles. This component represents over three-quarters of the noted fuel expenses. The remaining portion of fuel expense include~~s~~ disposal fees paid to the DOE pursuant to Title 10, Part 961, Appendix G of the Code of Federal Regulations. Exhibit A-1 represents these expenses on a per unit basis. Total fuel expenses, as depicted by column “F”, is simply the sum of columns “C”, “D”, and “E”.

Q. What is your opinion concerning the level of fuel expenses you have projected?

A. Fermi has been successful in managing its ore, enrichment services and fabrication fuel expenses for many cycles. An industry benchmark for ore and enrichment service pricing is the long term spot market. Fermi ore and enrichment service prices have been below the long term spot market for many cycles and this trend is expected to continue. The projected unit prices for ore and enrichment services assume the price will be less than market price. Fabrication pricing does not have an equivalent benchmark. Fermi controls fabrication costs with engineering time which maintains

Line No.

small reload batch sizes. Thus the number of fuel bundles remains optimum which lowers fabrication costs and reduces the required amount of ore and enrichment services. Projected prices and the total unit price are expected to remain below the sum of the component market prices, all of which have experienced significant changes in the past eight years. I am confident we can continue to manage these expenses effectively going forward and therefore, I believe the projected ore, enrichment services and fabrication fuel costs for Fermi are reasonable and prudent.

Q. What is the basis for your opinion that projected fuel costs for Fermi 2 are reasonable?

A. A number of concerted efforts contributed to this assessment. First, fuel assembly fabrication, uranium ore supply, and enrichment service pricing have been carefully and skillfully managed. Uranium ore supply and enrichment service have been established for a significant period of time to maintain price certainty. Therefore, as long term spot prices rise, these contracts will hold Fermi 2 prices below the long term price levels. Secondly, improved core design processes created by the Fermi 2 staff working with the fuel fabrication vendor have resulted in fewer fuel bundles required during core reloads. Based on the success and initiative of the Fermi 2 staff, I am confident we can continue to effectively manage future fuel expenses.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

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EXHIBIT

OF

ROBERT A. GAILLIEZ

Case No.:	U-16434
Exhibit No.:	A-1
Witness:	R. A. Gailliez
Page No.:	1 of 1

The Detroit Edison Company
Nuclear Fuel Expense Forecast
Years 2011 – 2015
($000)

(A) Year	(B) GWHr	(C) Fuel Amort	(D) In-core Interest	(E) Regulatory Cost	(F) Nuclear Fuel Exp	(G) $/MWHr	(H) Cents/ MBTU
======	======	======	======	======	======	======	=======
2011	9,579	48,031	0	8,842	56,873	5.94	57.7
2012	8,913	47,387	0	8,226	55,613	6.24	62.2
2013	8,931	48,907	0	8,243	57,150	6.40	64.3
2014	9,732	56,335	0	8,983	65,318	6.71	67.5
2015	8,927	53,667	0	8,239	61,906	6.94	69.7

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QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MICHAEL G. HOFFMAN

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF MICHAEL G. HOFFMAN

Line
No.

Q. What is your name, business address and who are you testifying on behalf of?

A. My name is Michael G. Hoffman. My business address is: One Energy Plaza, Detroit, Michigan 48226. I am testifying on behalf of The Detroit Edison Company ("Company" or "Detroit Edison").

Q. What is your current position?

A. I am currently Supervisor, Business Development, Fuel Supply.

Q. Please state your educational background.

A. My formal education consists of a Bachelor of Science of Civil Engineering degree from Michigan State University received in 1980. I have also completed several Company sponsored courses and have attended various conferences and seminars to further my professional development. I am also a registered Professional Engineer in the State of Michigan.

Q. Please summarize your professional experience.

A. In 1981 I joined Detroit Edison and was assigned to the Construction organization as an assistant engineer. During the first 3 years in this position I was responsible for developing project schedules and cost estimates, performing on-site inspections and performing special studies. Following the first 3 years I was responsible for managing construction projects.

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In 1988, I was assigned to the St. Clair Power Plant as an engineer where I was responsible for providing technical support to the operations and maintenance groups

In 1996, I transferred to the Resource Planning Organization. In this organization I performed studies of various power purchases and sales and resource plans using a production costing computer model (PROMOD).

In 1997, I transferred to the Fuel Supply Organization as a Specialist - Fuel Resources where my responsibilities included fuel transportation.

In 2001, I became Supervisor – Business Administration, Fuel Supply. My responsibilities included the procurement of coal, oil, natural gas and transportation and the administration of associated agreements.

In 2008, I began a cross-training assignment as Supervisor – Fuel Quality, Fuel Supply. My responsibilities included recording quality data and tracking contract quality compliance on all coal shipments, managing the chemical treatment of coal trains to minimize freezing during colder months, conducting periodic surveys of coal piles for the purpose of adjusting physical inventory records and providing technical support to Detroit Edison power plants relating to fuel quality.

In 2009, I began a cross-training assignment as Supervisor – Business Development, Fuel Supply. My responsibilities include assisting in the

Line No.

generation of short and long-term fuel plans, development of the annual fossil fuel budget and analysis of fossil fuel budget variances.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission?

A. Yes, I sponsored testimony in Case No. U-16047 (2010 PSCR Plan).

Line No.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to support the fossil fuel expense shown in Exhibit A-2.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibit:

Exhibit	Description
A-2	Fuel Expense Forecast, Years 2011-2015

Q. Was this exhibits prepared by you or under your direction?

A. Yes.

Q. Can you describe Exhibit A-2?

A. Exhibit A-2 is the five-year forecast (2011 through 2015) of fuel expenses, in total and by fuel type, for electric generation. Heat input requirements in total and by fuel type were provided by Ms. Wojtowicz. The average unit fuel cost for electric generation is also presented in this exhibit. Nuclear fuel expense is supported by Mr. Gailliez.

Q. What was the method used to develop the fuel expense forecast for 2011?

A. The 7 months actual, 5 months forecast (7&5 Outlook) for 2010 is the basis for the 2011-2015 forecast. The 7&5 Outlook uses actual August 1, 2010 inventory quantities and costs, and forecasts the remaining five months of 2010. The forecasted December 31, 2010 inventory quantities and costs are inputs to the 2011-2015 forecast.

The forecasted delivered coal costs for the last five months in 2010 and for 2011-2015 were determined using existing contract coal prices and transportation rates, forecasted spot market coal prices, and forecasted transportation rates. The forecasted spot market coal prices for 2011-2013 were based upon market information obtained from an over-the-counter (OTC) coal broker. For 2014 and 2015, spot market coal prices were estimated to remain constant with 2013 prices. The forecasted transportation rates were calculated by applying forecasted rail cost adjustment factors (RCAF) obtained from Global Insights to existing and forecasted transportation rates.

The forecasted delivered No. 2 and No. 6 oil and natural gas costs were determined by using the New York Mercantile Exchange (NYMEX) futures prices adjusted for basis and local distribution company (LDC) charges.

The composite monthly delivered coal cost for each plant was calculated by using Fuel Supply's Fuel Price Estimating (FPE) spreadsheet for the balance of 2010 and 2011-2015. The FPE applies existing and forecasted coal prices and transportation rates to the monthly delivery requirements for each plant. The coal delivery requirements are determined by subtracting actual coal pile inventory levels from the coal pile inventory level targets and adding the coal consumption requirements provided by Witness Wojtowicz. Delivery requirements for oil and gas are determined in a similar manner.

Line No.

The average annual unit cost of coal delivered to each Detroit Edison generation plant that burns coal was calculated in each year's FPE. The FPE output and delivered oil and gas delivery requirements and costs are used as inputs to the Forecasting Information and Budgeting System (FIBS) spreadsheet. Fossil fuel expense was calculated in FIBS by multiplying the average cost of inventory by fuel consumed.

Q. How does the Company intend to supply the coal that will be consumed during the forecast period?

A. The Company expects to supply its projected coal requirements for the forecast period through a combination of long-term and spot market purchases. This mix of purchases provides reliability of supply with sufficient flexibility to meet the needs of the Company's electric generating plants.

Q. Can you summarize the Company's long-term coal supply contracts?

A. Yes. The summary shown below is a numerical designation of each long-term (greater than one year) coal supply contract, the expected tonnage to be shipped in 2011, the free on board (F.O.B.) mine price (¢/MBtu), the term of the contract and the type of coal being supplied.

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Supplier	Tonnage	¢/Mbtu	Term	Coal Type
#1	3,000,000	81	5/10-12/13	LSW
#2	5,000,000	72	1/11-12/13	LSW
#3	3,000,000	64	1/10-12/12	LSW
#4	1,000,000	71	9/9-12/12	LSW
#5	1,720,000	78	1/10-12/12	LSW
#6	125,000	235	1/09-12/11	MSE
#7	500,000	266	10/07-12/11	MSE
#8	240,000	307	1/09-12/11	MSE
#9	1,000,000	248	6/09-12/11	MSE
#10	360,000	255	9/09-12/12	MSE
#11	1,000,000	244	9/09-12/12	MSE
#12	400,000	233	1/10-12/11	MSE

Q. How does the Company intend to supply the No. 2 oil that will be consumed during the forecast period?

A. The estimated requirements for No. 2 oil are expected to be supplied under agreements that are two years or less in duration based on a spot index price.

Q. How does the Company intend to supply the No. 6 oil that will be consumed during the forecast period?

A. The No. 6 oil requirements are expected to be supplied under spot market agreements that are one year or less in duration. This would also include the purchase of used oil, which is generally less expensive, when available. In addition, the Company expects to consume its internally generated waste oil.

Q. How does the Company intend to supply the natural gas that will be consumed during the forecast period?

A. The Company's natural gas supply requirements are expected to be met

Line No.

through a combination of MPSC approved tariffs with the local distribution companies (LDC's), spot market purchases and one long term (greater than one year) supply agreement based on a spot index price.

Q. What is the Company's projection regarding its use of coke oven gas as an alternative to coal and natural gas?

A. The Company's 2011 PSCR plan and five-year forecast include projections for the continued use of coke oven gas (COG) at Detroit Edison's River Rouge Power Plant. Coke oven gas is supplied by EES Coke Battery, LLC (EES Coke) under an agreement that began in June, 2009. As described in more detail by Mr. Johnston, electricity generated from COG creates Advanced Cleaner Energy Credits (ACECs), which Detroit Edison will use in its effort to address the Renewable Energy Credit Standard contained in 2008 PA 295, which was enacted on October 6, 2008.

Q. Can you explain the pricing provisions contained in the current COG Agreement?

A. Yes. Under the terms of this agreement, Detroit Edison pays EES Coke 95% of the average cost of coal consumed at River Rouge Power Plant for COG supplied and Detroit Edison has the right to retain all the ACECs produced from the generation of electricity from the combustion of COG under 2008 PA 295, the Michigan Clean, Renewable and Efficient Energy Act. Detroit Edison also has the right to sell the ACECs generated back to EES Coke for 10% of the average cost of coal consumed at River Rouge Power Plant resulting in a cost to Detroit Edison of 85% of the average cost of coal consumed at River Rouge

Line No.

Power Plant for COG. However, for purposes of the Company's 2011 PSCR Plan, I have only reflected a projected COG expense of 80% of the average cost of coal consumed at River Rouge Power Plant. Witness Johnston will explain the proposed recovery treatment of any expense in excess of that amount.

Q. What is your opinion regarding the Present COG Agreement?

A. The June 2009 COG Agreement allows the Company to consume COG and, as a result displace a portion of higher cost coal and natural gas consumption at Detroit Edison's River Rouge Power Plant resulting in lower electric rates for Detroit Edison electric customers, and therefore its continued use is reasonable and prudent.

Q. Are there any significant cost increases that contribute to the increase in fuel expense for 2011?

A. Yes. A significant increase in forecast coal expense in 2011 is due to the replacement of an unusually competitive long term (13-year) rail transportation agreement that expires on December 31, 2010 with a new rail transportation agreement beginning January 1, 2011.

Q. What are the differences between the two rail transportation agreements that account for the increase in expense?

A. In 1998, Detroit Edison entered into a 10-year coal transportation agreement with a western rail carrier effective January 1, 1998 to transport low-sulfur western Powder River Basin (PRB) coal to the Midwest Energy Resource Company (MERC) terminal for further transportation by vessel to

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Detroit Edison's Electric generation plants and to also interchange in Chicago with other delivering rail carriers for further transportation to Detroit Edison's electric generation plants (1998 Agreement). The expiration date of the original 1998 Agreement, was December 31, 2007, but in March of 2003 Detroit Edison was able to negotiate a favorable amendment (2003 Amendment) to the agreement, which extended the expiration date to December 31, 2010. The transportation rates, as adjusted per the agreement were moderately below market rates over the first 6 years of the agreement. However, beginning in 2004, due to western railroad duopoly pricing supported by non-confidential rates, railroad favorable Surface Transportation Board (STB) decisions and PRB coal's cost advantage over other fuels, significant increases were experienced in market rail rates for PRB coal transportation. Due to these significant increases in market rates, the rates as adjusted per the 1998 Agreement and the 2003 Amendment, are significantly below present market rates. In addition, the rate escalation methodology contained in the 1998 Agreement was capped annually and Detroit Edison was not subject to the payment of a fuel surcharge, a new industry standard, which all railroads began instituting in new rail transportation agreements beginning in 2004. Over the period from 2004 through 2010, Detroit Edison estimates that the 1998 Agreement and the 2003 Amendment saved its customers $1.1 billion compared to market rates. In 2009, Detroit Edison solicited proposals from both western rail carriers. The proposals were evaluated and subsequent negotiations resulted in Detroit Edison entering into a new confidential rail transportation agreement with the same western rail carrier with a term beginning January

Line No.

1, 2011 and ending December 31, 2015 (2011 Agreement).

Q. What has been done to mitigate the effect of the increased cost of the 2011 Agreement?

A. Detroit Edison is purchasing and transporting a significant amount of additional PRB coal in 2010 that will ultimately be consumed in 2011. This additional coal will be transported at the lower 1998 Agreement and 2003 Amendment rates and will reduce the amount of PRB coal to be transported at the higher 2011 Agreement rates in 2011. The pre-shipment of this PRB coal in 2010 will reduce fuel expense by approximately $24 million in 2011.

Q. What is your opinion regarding the value of the 2011 Agreement entered into by Detroit Edison?

A. The rates in the 2011 Agreement include a fuel surcharge and are significantly higher than the rates in the 1998 Agreement and 2003 Amendment, but are moderately below the 2011 market rail rates and below Detroit Edison's only other rail transportation alternative. In addition, the 2011 Agreement allows Detroit Edison to continue to purchase and transport Montana origin PRB coal, which has a lower delivered cost per Mbtu than Wyoming origin PRB coal, for its St. Clair and Belle River Plants. The other western carrier does not have access to Montana origin PRB coal. The rates in the 2011 Agreement are estimated to save Detroit Edison's customers approximately $200 million to $230 million over the term of the agreement compared to the market and the other western rail carrier's proposal.

Line No.

In light of the above circumstances and since the 2011 Agreement meets Detroit Edison's PRB rail transportation requirements, I believe that the 2011 Agreement is reasonable and prudent.

Q. What are some of the major assumptions supporting the coal forecast presented on Exhibit A-2?

A. The long-term forecast of coal prices assumes the Company's continued reliance on low sulfur western (LSW) coal. For 2011, approximately 79% of all coal consumed is projected to be LSW coal. The LSW coal is procured from the Powder River Basin, which is located in southern Montana and northeastern Wyoming. The balance of the Company's coal is purchased from Central and Northern Appalachia. Coals from these regions include low sulfur eastern (LSE), mid sulfur eastern (MSE) and high sulfur eastern (HSE).

Q. Are there any other factors that could affect fuel costs in 2011?

A. The only other known factor that could affect fuel cost is the Reduced Emission Fuel Project (REF Project) at Edison's Belle River and St. Clair Power Plants. The REF Project is a process that involves the application of chemical additives to the coal just prior to conveying the coal into the plant bunkers. This process produces what is referred to as a Reduced Emissions Fuel (a/k/a Refined Coal) and is done for the sole purpose of reducing emissions and their related costs. The Refined Coal is expected to reduce SO_2, mercury (Hg) and NOx emissions and therefore the related emission allowance expense experienced by Detroit Edison.

Line No.

The additive itself, as well as the western coal that it is to be applied to, will be purchased by Edison from affiliated companies (Fuels Companies). The coal will be purchased by the Fuels Companies and transported by Detroit Edison to its Belle River and St. Clair Power Plants at the same delivered cost that would have been incurred absent the use of the REF Project. Witness Johnston discusses the propriety of this transaction.

Q. What additional costs are associated with this REF Project?

A. The PSCR cost of the chemical additives applied to the coal (Refined Coal Adder) will be the lower of the PSCR benefit of reduced SO_2 and mercury emissions associated with the consumption of the Refined Coal or the revenue requirement associated with the REF Project production facility. Thus, until such time as the plants experience an actual and measurable reduction in SO_2 or mercury emissions, the cost of the Refined Coal Adder will be zero. Once the plants experience reduced emissions, the cost of the Refined Coal Adder will be no greater than the benefits of the reduced emission allowance expense capped at the amount of the revenue requirement associated with the REF Project facility. Once the cost of the Refined Coal Adder reaches this cap, any additional benefits of reduced emission allowances will flow directly through to the PCSR customers. In summary, the cost of the Refined Coal Adder, if any, will be entirely offset by a corresponding savings in PSCR emissions allowance expense.

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Q. Can you describe the expected reductions for NOx emissions as a result of the REF Project?

A. Indications are that the use of Refined Coal will also result in reductions of NOx emissions and, therefore, a reduction in annual and seasonal NOx emission allowance expense. These benefits will flow directly to the PSCR customer and will not be reflected in the determination of the Refined Coal Adder. Detroit Edison negotiated this benefit because the level of NOx emissions can be impacted by various factors and it would be difficult to measure the precise level of reduced NOx emissions related to the Refined Coal.

Q. What is the forecasted cost of the Refined Coal Adder included in the five-year forecast?

A. The level of SO_2 emissions reductions provided by Witness Wojtowicz result in a Refined Coal Adder cost of $53,528, $20,125, $13,643, $9,160 and $25,737 respectively, in the forecast years 2011 – 2015. In addition, the 2015 Refined Coal Adder cost includes $9.9 million associated with avoided mercury emissions expense. The forecast Refined Coal Adder costs appear on line 5 of Exhibit A-2. This forecast increase in fuel expense related to the Refined Coal Adder will be more than offset by a reduction in PSCR expense due to reduced emission allowance expense and ultimately the rates for Detroit Edison electric customers.

Q. What is your opinion regarding the fuel supply plan that you are presenting?

A. I believe that the fuel supply plan developed meets Detroit Edison's

Line No.

requirements, is consistent with both the Company's policies and objectives, provides for the delivery of electric generation to customers at a reasonable price given market conditions, and is a reliable supply plan that is both reasonable and prudent.

The Company has aggressively tested and burned LSW coal at various Company electric power plants. This supply option is not only economic, but also among the cleanest coals available.

The Company has also continued to expand the "arena of competition" for both eastern and western coals. The ability to blend and burn coals from several coal supply regions along with utilizing multiple transportation options has provided the Company with the leverage to negotiate some of the most competitive delivered fuel prices available.

The Company maintains one of the largest utility railcar fleets, not only to facilitate control over delivery of coal, but also to optimize the cost savings associated with rail transportation in private equipment.

The Company continues to aggressively market coal and transshipment services to third parties through its subsidiary, MERC. Third party revenues and the equity received from MERC's joint venture contribute to a reduction in Detroit Edison's fuel expense and ultimately the rates for Detroit Edison electric customers.

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The Company is also determined to pursue all reasonable avenues to resolve disputes with its suppliers, including negotiation, arbitration and litigation, when necessary.

Considering the above, as well as the actions the Company has taken to minimize fuel costs, and given that the Company expects to cover a majority of its fossil fuel requirements with coal, I believe that Detroit Edison's present fuel supply policy, objectives, and strategies (as set forth in my testimony and exhibit) are reasonable and prudent.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
THE DETROIT EDISON COMPANY	)	
for Authority to Implement a Power	)	Case No. U- 16434
Supply Cost Recovery Plan in its	)	
Rate Schedules for 2011 Metered	)	
Jurisdictional Sales of Electricity	)	

EXHIBIT

OF

MICHAEL G. HOFFMAN

The Detroit Edison Company
Fuel Expense Forecast
Years 2011 - 2015

Case No.: U-16434
Exhibit No.: A-2
Witness: M.G. Hoffman

	(a)	(b)	(c)	(d)	(e)	(f)
		2011	2012	2013	2014	2015
1	Coal**					
2	MBtu (000)	377,008	376,894	382,024	386,187	401,863
3	¢/MBtu	234.1	276.4	304.3	317.1	324.9
4	$ (000)	882,765	1,041,631	1,162,648	1,224,759	1,305,587
5	Refined Coal Adder	53	20	14	9	9,938
6	$ (000)	882,817	1,041,651	1,162,662	1,224,768	1,315,525
7						
8	No.2 Oil*					
9	MBtu (000)	767	774	788	780	838
10	¢/MBtu	1,643.8	1,721.2	1,696.4	1,685.3	1,704.6
11	$ (000)	12,613	13,328	13,363	13,144	14,288
12						
13	No.6 Oil					
14	MBtu (000)	964	137	165	193	169
15	¢/MBtu	836.9	781.1	785.4	783.1	784.1
16	$ (000)	8,065	1,073	1,296	1,512	1,327
17						
18	Natural Gas**					
19	MBtu (000)	4,750	5,046	4,971	5,654	5,526
20	¢/MBtu	579.7	594.9	595.8	617.7	625.6
21	$ (000)	27,534	30,018	29,617	34,924	34,569
22						
23	Coke Oven Gas					
24	MBtu (000)	789	808	861	879	824
25	¢/MBtu	205	295	298	318	318
26	$ (000)	2,099	2,385	2,564	2,796	2,620
27						
28	Total Fossil					
29	MBtu (000)	384,278	383,660	388,809	393,693	409,220
30	¢/MBtu	242.8	283.7	311.1	324.4	334.4
31	$ (000)	933,129	1,088,456	1,209,502	1,277,144	1,368,330
32						
33	Nuclear Fuel					
34	MBtu (000)	98,567	89,410	88,880	96,767	88,818
35	¢/MBtu	57.7	62.2	64.3	67.5	69.7
36	$ (000)	56,873	55,613	57,150	65,318	61,906
37						
38	All Fuels					
39	MBtu (000)	482,845	473,070	477,689	490,460	498,038
40	¢/MBtu	205.0	241.8	265.2	273.7	285.2
41	$ (000)	990,002	1,144,069	1,266,652	1,342,462	1,430,236

* Excludes MPPA's portion of Belle River
** Includes Industrial Steam

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
THE DETROIT EDISON COMPANY	)	
for Authority to Implement a Power	)	Case No. U-16434
Supply Cost Recovery Plan in its	)	
Rate Schedules for 2011 Metered	)	
Jurisdictional Sales of Electricity	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KENNETH D. JOHNSTON

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF KENNETH D. JOHNSTON

Line No.

Q. What is your name, business address and by whom are you employed?

A. My name is Kenneth D. Johnston. My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services LLC within Regulatory Affairs as a Regulatory Consultant

Q. On whose behalf are you testifying?

A. I am testifying on behalf of The Detroit Edison Company (Company or Detroit Edison).

Q. What is your educational background?

A. I graduated from Lawrence Technological University with a Bachelor of Science Degree in Engineering in 1983. In 1991, I graduated with distinction from the University of Michigan, Dearborn, with the degree of Master of Business Administration in Finance and received the Distinguished Graduate MBA Student Award. In addition, I have completed advanced level mathematics and mechanical engineering courses at Lawrence Technological University.

Q. Have you completed other courses of study or attended any professional seminars?

A. Yes, I have completed a Training Program titled Fundamentals of Energy Management sponsored by the Association of Energy Engineers, completed a training course offered by International Business Communications titled Energy Industry Essentials, attended a workshop

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on Retail Open Access offered by the Michigan Electric Power Coordination Center, attended the Lighting Upgrade Workshop offered by the US Environmental Protection Agency (EPA), and completed the Nuclear Utility Procurement Training sponsored by the Electric Power Research Institute (EPRI). In addition, I graduated from Leadership Oakland XI, 2000-2001 Program Year, a non-profit organization whose mission is to ensure the continuing vitality of Oakland County by preparing motivated leaders who are educated about the county and its issues.

Q. Do you belong to any professional organizations or hold any certifications?

A. Yes. I have received certifications as an Energy Manager through the Association of Energy Engineers, a Green Lights Surveyor Ally through the US EPA, and as a Nuclear Utility Procurement Instructor through EPRI.

Q. Please review your employment history with Detroit Edison.

A. My first work assignment for Detroit Edison Company was in May 1983 as a contract engineer in the Applied Mechanics and Metallurgy Group, Power Systems Division, Engineering Research Department. As a vibration engineer, I was responsible for vibration monitoring, evaluation, and analysis of rotating machinery at Detroit Edison Power Plants.

I was formally hired by Detroit Edison in August 1985 as a planning and

Line
No.

scheduling engineer at the Fermi 2 Nuclear Power Plant. In this capacity I developed, programmed, and directed the production of plant outage schedules, including equipment maintenance and testing, plant system restoration, and plant startup.

In March 1989, I was assigned the duties of Preventive Maintenance Specialist, Nuclear Production-Maintenance, and was responsible for evaluation and implementation of the preventive maintenance program.

In January 1990, I took a position as a materials engineer, Nuclear Materials Management, and progressed to principal (lead) engineer. In this capacity, I was responsible for the work direction of engineers and technicians in the performance of material engineering, parts planning, and receipt inspection activities. I represented the Company as a member of the EPRI Obsolete Items Database Technical Working Group and the General Electric Boiling Water Reactor Pooled Inventory Management Equipment Committees.

In August 1995, I was assigned the position of principal mechanical maintenance engineer, Rotating Equipment, Maintenance Engineering, Nuclear Production. In this capacity I provided field-engineering support for mechanical maintenance activities, managed the resolution of emerging technical issues, monitored and evaluated the performance of rotating equipment and performed troubleshooting and root cause analysis of equipment failures.

Line No.

In January 1997, I became a facilitator with the Energy Partnership, Customer Energy Solutions. In this position, I was responsible for the development, implementation, and management of the Energy Conservation Program at the General Motors Proving Ground in Milford, Michigan. Responsibilities in that position included the identification, financial evaluation, and implementation of natural gas and electric energy projects related to boiler and steam systems, lighting systems, air compressors, and HVAC systems.

In June 1999, I became a Principal Supplier Account Manager with the Supplier Transactions Group of the Electric Choice Implementation Team. In this capacity I was responsible for the management of relationships with Alternative Electric Suppliers (AESs) including supplier education, supplier qualification, supplier billing, customer enrollment, customer billing, and electronic data management.

In January 2003, I transferred to Regulatory Affairs as a Principal Project Manager and in September 2007, I was promoted to Consultant.

Q. What are your duties and responsibilities within Regulatory Affairs?

A. I am responsible for coordinating, managing and providing expert testimony on various rate matters before the Michigan Public Service Commission (MPSC) and the Federal Energy Regulatory Commission (FERC). The subject matter of such testimony includes Electric Choice (implementation cost recovery, rates, tariff administration, transition charges, code of conduct, market priced power, and program participation), renewable energy, transmission & ancillary services (rates, billing, energy scheduling, energy imbalance service), energy efficiency, rates for industrial send-out steam, and wholesale-for-resale rates. I have prepared monthly fuel adjustment factors for industrial steam rates and wholesale for resale rates, the Power Supply Cost Recovery (PSCR) 45-day report, and monthly calculations for Detroit Edison's transmission related ancillary services for purposes of Midwest Independent Transmission System Operator (MISO or Midwest ISO) Billing. Previously, I was vice-chair of the now retired MISO Retail Market Working Group.

Q. What has been your involvement in rate case activities?

A. I have managed or am actively managing the following cases:

U-13738	In the matter of the application of The Detroit Edison Company to recover implementation costs for the period ended December 31, 2002
U-14079	In the matter of the application of The Detroit Edison Company to recover implementation costs for the period ended December 31, 2003
U-13759	Review of Steam Rates
U-13808-R	2004 Power Supply Cost Recovery Reconciliation
U-14474	In the matter of the application of The Detroit Edison Company to implement the Commission's final order in Case No. U-13808 concerning Inter Alia, 2004 Net Stranded Costs
U-14093	In the matter of the complaint of North Star Steel Company against The Detroit Edison Company regarding credits for

experimental electric choice service

U-14124	In the matter of complaint of Nordic Marketing, LLC against The Detroit Edison Company for violations of the Code of Conduct, Public Act 141
U-15223	In the matter of the complaint of Commerce Energy Inc. against The Detroit Edison Company
U-16400	In the matter of the application of MICHIGAN CONSOLIDATED GAS COMPANY for the authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of natural gas, and for miscellaneous accounting authority.

I was the case manager and/or sponsored testimony in the following Detroit Edison cases:

U-14025	In the matter of the complaint of Strategic Energy LLC against The Detroit Edison Company
U-14054	In the matter of the complaint of Quest Energy against The Detroit Edison Company
U-14070	In the matter of the complaint of Constellation NewEnergy, Inc. against The Detroit Edison Company.
U-14275	2005 Power Supply Cost Recovery Plan
U-14275-R	2005 Power Supply Cost Recovery Reconciliation
U-14208	In the matter of the complaint of Nordic Marketing, L.L.C. against The Detroit Edison Company for failure to comply with enrollment processing requirements.
U-14817	2005 Pension Equalization Mechanism Reconciliation

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No.

U-14702	2006 Power Supply Cost Recovery Plan
U-14702-R	2006 Power Supply Cost Recovery Reconciliation
U-15259	2006 Pension Equalization Mechanism Reconciliation
U-15002	2007 Power Supply Cost Recovery Plan
U-15002-R	2007 Power Supply Cost Recovery Reconciliation
U-15081	In the matter of the complaint of FirstEnergy Solutions Corp. against The Detroit Edison Company for violation of the Code of Conduct
U-15417	2008 Power Supply Cost Recovery Plan
U-15417-R	2008 Power Supply Cost Recovery Reconciliation
U-15677	2009 Power Supply Cost Recovery Plan
U-15806	Detroit Edison 2008 PA 295 Renewable Energy Plan (RPS)
U-16047	2010 Power Supply Cost Recovery Plan
U-16356	In the matter of the application of The Detroit Edison Company for the authority to reconcile its renewable energy plan costs with the plan approved in Case No. U-15806-RPS

In addition, I was the case manager and submitted affidavits supporting the approval of renewable energy, renewable energy engineering, procurement and construction (EPC), and renewable energy credit (REC) contracts before the MPSC and I was the case manager and submitted several affidavits regarding energy imbalance service and the recalculation of energy imbalance service costs in FERC Docket EL04-31-000, "Complaint of Quest Energy, LLC to receive proper compensation for imbalance services", and was

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the case manager in FERC Docket EL04-119-000, "Complaint of Quest Energy, L.L.C. against Detroit Edison Company."

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Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide the calculation of the PSCR billing factors to be utilized for each month of 2011. I have also calculated projected average annual PSCR billing factors for the years 2012 through 2015.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-3	Power Supply Cost Recovery Factor, Forecast Period January 2011 through December 2011
A-4	Power Supply Cost Recovery Factor, Forecast Period 2012 through 2015

The 2011 levelized monthly PSCR billing factor of (2.98) mills/kilowatt-hour is developed on Exhibit A-3. PSCR billing factors for the years 2012 through 2015 appear on Exhibit A-4.

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. How were the PSCR billing factors calculated?

A. The calculations are based on the change in the average unit cost of power supply above or below a base of 31.26 mills per kWh. The average unit cost is determined on a net system requirement basis, exclusive of the MWh and

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dollars associated with R-10 and similar interruptible loads. This methodology is consistent with prior years' calculations, prior Commission orders including the January 13, 2009 Order in MPSC Case No. U-15244 and Section C8.1 of the Detroit Edison Company Rate Book for Electric Service.

Q. Is the Company requesting approval of any cost elements in the 2011 PSCR Plan which are not currently reflected in the PSCR base?

A. Yes. The Company is requesting that the Commission recognize the incremental cost of urea as an integral part of the cost of power supply and includible in PSCR expenses. An additional discussion of urea is presented in the testimony of Detroit Edison Witness Ms. Wojtowicz.

Q. Why should the costs of urea be recovered in the PSCR clause?

A. As further explained in the testimony of Ms. Wojtowicz, there is a direct tradeoff between the consumption of urea in the selective catalytic reduction (SCR) units and the consumption of NO_X emission allowances, the expense of which is already included in the PSCR. In order to make the proper economic decisions between various power supply alternatives within the PSCR, the expense of both urea and NO_X emission allowances should be reconciled within the PSCR clause. This treatment is necessary to ensure the most economic use of urea and NO_X emission allowances in combination with fuel purchases. In other words, the power supply decisions should be driven by system economics and not influenced by cost recovery.

Line No.

Q. Has the Commission previously approved the recovery of urea expense in power supply cost recovery plans?

A. Yes. The Commission's November 13, 2008 Order in Consumer Energy's 2008 PSCR Plan Case No. U-15415 approved the recovery of urea as a disposal cost. Detroit Edison uses urea in the operation of the SCRs at the Company's Monroe Power Plant on units 1, 3, and 4. Urea is solely used in the SCRs to reduce oxides of nitrogen (NO_x) emissions. NO_x emissions result from the fuel combustion process that takes place in the process of generating electricity. MCL 460.6j(1)(a) allows:

> "…the utility to recover the booked costs, including transportation costs, reclamation costs, and disposal and processing costs, of fuel burned by the utility for electric generation.."

Not consuming urea in the SCRs would result in the consumption of additional NO_x emission allowances at a cost per ton that is significantly higher than that of urea. The Commission agreed when it stated:

> "Just as there is a direct connection between the quantity and type of fuel burned and the need to purchase emissions allowances there is also a direct connection between fuel burned, emissions, and urea expense. Allowing the recovery of urea expense as a disposal cost of the fuel burned by the utility is consistent with the language of MCL 460.6j(1)(a)." (MPSC Case No. U-15415, Order dated November 13, 2008, pp. 11-12)

Thus, the Company believes that urea consumption is not only a reasonable and prudent expense, but also an expense that should be recovered as a cost of fuel burned and/or disposal cost of fuel burned

Line No.

and recovered through the PSCR pursuant to MCL 460.6j(1)(a). The Commission has also previously issued Orders in Detroit Edison's 2009 and 2010 PSCR Plan proceedings that authorized PSCR factors including incremental urea expense. The Company is requesting ongoing Commission approval for this ratemaking expense treatment in the PSCR.

Q. What adjustments, if any, has the Company made to its projected urea expense in the 2011 PSCR Plan?

A. The Company has reduced its projected 2011 urea expense by $7.528 million (see Exhibit A-20) the amount reflected in the Company's rate relief pursuant to the Commission June 11, 2010 Order in MPSC Case No. U-15768. The inclusion of urea expense in the PSCR for 2011 reduces the overall PSCR Plan cost by almost $0.025 million before taking into account the reduced NO_x emission allowance expense as a result of operating the Monroe Power Plant SCRs.

Q. Has the Company reflected the costs associated with other emission-related efforts in its 2011 PSCR plan filing?

A. Yes. The Company's filing includes projections related to the consumption of Reduced Emissions Fuel (REF) at its Belle River and St. Clair Power Plants. The Company continues to evaluate REF as an alternative to (1) obtaining SO_2 and NO_x emission allowances and (2) minimize the costs associated with reducing mercury (Hg) emissions at its Belle River and St. Clair Power Plants. The Company has not made a commitment to move forward with the implementation of this alternative for the 2011 PSCR Plan year but is

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supporting the proposed methodology should it make a decision to do so. It is important to note that regardless of the Company's decision to move forward with REF in 2011, that decision will have no impact on the Company's requested maximum PSCR factor for 2011.

Q. Can you provide any details as to how REF would be implemented at the Belle River and St. Clair Power Plants?

A. Yes. A number of activities would occur including the sale of a portion of Detroit Edison's coal inventory to the (Belle River Fuels Company and St. Clair Fuels Company or Fuels Companies), the provision of coal handling and consulting by Detroit Edison to the Fuels Companies and the delivery of REF from the Fuels Companies to Detroit Edison. DTE Energy Services, the parent company of the Fuels Companies, has a license to use the unique and proprietary chemical additive technology at DTE Energy sites. In addition, arrangements exist for purposes of environmental indemnity protection and payment for other Detroit Edison services to the Fuels Companies.

Q. Can you summarize the Coal Inventory Purchase?

A. Yes. Detroit Edison will sell a portion of its coal inventories to the Fuels Companies at their book costs. Because all of the coal will ultimately be resold to Detroit Edison as REF, I believe it is appropriate to make this transaction at book cost and not unnecessarily inflate the cost of the REF. Detroit Edison customers will ultimately benefit from reduced costs associated with carrying the relevant fuel inventory on its books when base

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rates are reset. At the end of the 10-year REF consumption period, the coal inventory will be resold to Detroit Edison at the Fuels Companies' book costs.

Q. Can you summarize the details of the Refined Coal Supply from the Fuels Companies?

A. Yes. The Fuels Companies will supply REF to Detroit Edison on a "just in time" delivery basis. The Fuels Company REF facilities were constructed on the Belle River and St. Clair Power Plant sites and were integrated into the Company's coal delivery process. The cost of the REF will be based upon the booked cost of coal (no different than if Detroit Edison continued to own the coal), and the lesser of (1) the revenue requirements associated with producing the REF or (2) the environmental benefits (SO_2 emission allowance expense reduction and future avoidance of mercury emission abatement expense as discussed by Edison Witness Michael G. Hoffman) of the REF less any increased purchased power cost associated with 1989 PA 2 suppliers as discussed by Witness Wojtowicz.

Q. Can you summarize the details of the other arrangements?

A. Yes. The provision of coal handling and consulting and other services reflect the provision of services at Detroit Edison's cost to the Fuel Companies to support the provision of REF to the Belle River & St. Clair Power Plants. The basis for providing these services at cost is that these services are only supporting the provision of REF to the Belle River & St. Clair Power Plants and may ultimately be flowed back to Detroit Edison as

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part of the revenue requirement determinations. In other words, the costs of these services are a zero-sum proposition with costs charged to the Fuels Companies ultimately flowing back to Detroit Edison.

Q. What impact, if any, will the implementation of REF have on other PSCR items?

A. As discussed by Detroit Edison Witness Mr. Hoffman, the REF is also expected to reduce NO_x emission allowance expense and mercury emission abatement expense. Due to the variability of NO_x emissions, this cost reduction cannot be precisely estimated but the result will be a benefit to the PSCR customer as a result of consuming fewer NO_x annual and seasonal emission allowances.

Q. Is the Company requesting the recovery of any mercury emission-related expense in the Company's PSCR Plan?

A. No. However, for purposes of providing a complete 5-year power supply forecast, Ms. Wojtowicz has provided an estimate of the mercury emission related expense for 2015, the first compliance year for Michigan Rule 1503 (R 336.2503 Mercury emission standards for electric generating units). As discussed by Ms. Wojtowicz, the Company expects to use activated carbon to address these mercury reduction requirements at several of its power plants and expects to request recovery of the sorbents used in this process through the PSCR, similar to urea expense. In addition, Ms. Wojtowicz has provided a projection of the mercury emission expense reductions related to the implementation of REF.

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Q. Since Detroit Edison Witness Ms. Siefman explains that much of Detroit Edison's non-jurisdictional (FERC Wholesale for Resale) sales will not continue through the five-year forecast period, does the Company plan to request different treatment for its non-jurisdictional sales for resale sales in the PSCR?

A. Yes. Ms. Siefman indicates that the Wolverine Power Supply Cooperative (Wolverine) contract will expire at the end of 2011.[1] As a result, in the event that the Company's next general electric rate case is filed such that its projected test period overlaps the 2011 PSCR Plan period, the Company may propose that for the remainder of the Wolverine contract, that all revenues received from the Wolverine contract no longer be treated as requirements service but rather they be treated as other sales for resale or interconnection (Account 447) sales, such as MISO sales, are treated. This methodology will allow for a smooth and fair transition for the sales for resale revenues related to this contract.

Q. How is the impact of the aforementioned methodology reflected in the Company's proposed maximum PSCR Factor?

A. The Company will not implement such a change until such time as a final order in the Company's next general electric rate case approves such a proposal.

Q. How would the Company address the amount that it would self-implement under Section 6a of 2008 PA 286 to ensure that no double

[1] The Sebewaing and Croswell Wholesale for Resale contracts expire in 2010.

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collection of revenues would occur?

A. Depending on the timing of the Company's next general electric rate case and the Commission's decision regarding the Company's proposed request for treatment of Wolverine contract revenues, the Company expects to fully credit the PSCR for all Wolverine contract revenues in excess of those already allocated to the PSCR dependent upon approval of this proposal in a final Commission Order in the Company's next general electric rate case. This will allow customers to receive that benefit through the PSCR in the timeliest manner available to the Company.

Q. Since Mr. Hoffman discusses the current coke oven gas agreement (COG Agreement), what is the basis for the Company's allocation of the expense associated with the COG Agreement?

A. The COG Agreement continues to provide for consumption of COG at a discount to coal, effectively reducing the cost of fuel burned at Detroit Edison's River Rouge Power Plant, thereby reducing PSCR expense. In addition, the new contract reflects the value associated with the generation of Advanced Cleaner Energy Credits (ACECs) which, pursuant to 2008 PA 295 (enacted on October 6, 2008) can, at times, be substituted for the Renewable Energy Credits (RECs) utilized by the Company in its efforts to address the Renewable Energy Credit Standards. Thus, as discussed by Mr. Hoffman, Detroit Edison has projected its PSCR COG fuel expense at 80% of the average cost of coal for the River Rouge Power Plant.

Q. How will the balance of the expense associated with the COG

Line No.

Agreement be treated?

A. The Company will record any expense associated with the delivery and consumption of coke oven gas that exceeds 80% of the average cost of coal for the River Rouge Power Plant as an O&M expense associated with Detroit Edison's 2008 PA 295 renewable energy program. This methodology is consistent with the August 10, 2010 Order in the Company's 2010 PSCR Plan Case No. U-16047. The actual amount recorded as O&M expense, either 5% or 15% of the average cost of coal for the River Rouge Power Plant, will be dependent on both Detroit Edison's needs for Advanced Cleaner Energy Credits (ACECs) to address the Renewable Energy Credit Standards contained in 2008 PA 295 as well as the legislation's limitations on the substitution of ACECs for RECs to meet the Renewable Energy Credit Standards.

Q. Does 2008 PA 295 provide for unlimited substitution of ACECs for RECs?

A. No. MCL 460.1027 subsections 7 and 8 limit the substitution of ACECs:

> (7) Under subsection (6), energy optimization credits, advanced cleaner energy credits, or a combination thereof shall not be used by a provider to meet more than 10% of the renewable energy credit standards. Advanced cleaner energy from advanced cleaner energy systems in existence on January 1, 2008 shall not be used by a provider to meet more than 70% of this 10% limit. This 10% limit does not apply to advanced cleaner energy credits from plasma arc gasification.
>
> And:
>
> (8) Substitutions under subsection (6) shall be made at the following rates per renewable energy credit:
> (a) One energy optimization credit.

Line No.

> (b) One advanced cleaner energy credit from plasma arc gasification or industrial cogeneration.
> (c) Ten advanced cleaner energy credits other than from plasma arc gasification or industrial cogeneration.

Since both the EES Coke Battery and Detroit Edison's River Rouge Power Plant existed before January 2008 and the burning of COG does not constitute plasma arc gasification, the most restrictive one-for-one ACEC substitution limitations apply. Therefore, it was important for Detroit Edison to not pay for more ACECs than it could possibly use under 2008 PA 295. The Company's ability to effectively sell the ACECs back to EES Coke Battery, LLC allows the Company to actively manage the number of ACECs that it keeps as part of the new COG agreement and continue to obtain a lower cost fuel source for the River Rouge Power Plant.

Q. Has the Company included any provision for an over/(under) recovery from the 2010 PSCR period in the 2011 PSCR Plan?

A. Yes. At the time of this filing, Detroit Edison projects that it will have a PSCR under-recovery for the 2010 PSCR period amounting to $36.349 million. The Company increased its PSCR factor on a bills-rendered basis for all customers effective July 1, 2010 in an effort to minimize the under-collection projected at that time for the 2010 PSCR period. It is important to note that this projection could change based upon actual results for the balance of the 2010 PSCR Plan period and/or the final order in its 2009 PSCR Reconciliation Case No. U-15677-R. The Commission granted the Company continuing authority to roll prior year under and over-recoveries into its future power supply cost recovery plans in its December 21, 2006

Line No.

Order Approving Temporary Factors in the Company's 2007 PSCR Plan Case No. U-15002.

Q. Witness Wojtowicz reflects power purchases to support the Company's renewable energy plan, can you explain the bases for these projections?

A. Yes. Public Act 295 of 2008 created a Renewable Energy Credit Standard which targets a renewable energy credit portfolio of 10% by 2015, and includes interim targets for 2012, 2013 and 2014. Witness Wojtowicz's purchased power reflects renewable energy utilization directed towards attainment of those goals.

Q. Has the Company entered into any specific Renewable Energy Contracts or begun construction on any Renewable Energy Systems towards attainment of the interim Renewable Energy Credit and Capacity Standards?

A. Yes. At this time, the Company has entered into Renewable Energy Contracts totaling as much as 252 MW of renewable energy capacity and energy (See MPSC Case Docket No. U-15806 for additional details). The Company's Renewable Energy Plan which was filed on March 4, 2009 and approved by the Commission on June 2, 2009 contains more detailed discussions regarding attainment of the Renewable Energy Credit and Capacity Standards and specific renewable energy generation projects and renewable energy credit purchases.

Q. How will the renewable energy and capacity reflected in Witness

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Wojtowicz's purchased power portfolio be priced for purposes of this proceeding?

A. PA 295 of 2008 requires the Commission to annually establish a price per megawatt hour (transfer price) at which price the energy and capacity will be furnished to retail customers through the PSCR mechanism. Ultimately, the Commission will set the price at which the energy and capacity will be provided to retail customers through the PSCR in the renewable cost reconciliation proceedings. Witness Wojtowicz explains the source of the actual pricing.

Q. What factors would the Company self-implement on January 1, 2011?

A. The Company intends to self-implement a maximum PSCR billing factor of (2.98) mills/kWh on January 1, 2011 for all customers. This PSCR factor represents the Company's projected 2011 PSCR costs including the projected incremental urea expense. However, should the Commission rule on the Company's 2009 PSCR Reconciliation Case No. U-15677-R prior to that time, the Company will adjust its PSCR billing factor accordingly.

Q. What contingency amounts has the Company included, if any, in power supply expense to account for potential fluctuations in Electric Choice sales levels?

A. The Company has not included any contingency adjustments to power supply expense as was proposed in its 2006 PSCR Plan. The Company's power supply expense has been determined in accordance with a 2011 Electric Choice sales forecast level of 4,987 GWh as discussed in the

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testimony of Witness Ms. Siefman.

Although the Company's Electric Choice return to service provisions allow Electric Choice customers to notify Detroit Edison that they will be returning to Detroit Edison full electric service for the 2011 PSCR Plan year as late as December 1, 2010, the Company has several alternatives to including contingency power supply costs in its projections. The first of these is that the Company has the ongoing Commission authority to include its projected over/(under) collections from prior years in its future year PSCR Plans. This methodology helps to eliminate the time lag between the incurrence and refund/recovery of over/(under) collected PSCR expense. A second alternative is to amend its Electric Choice projections and associated cost impacts with supplemental filings or by reopening the case. Since the Company can always lower its PSCR factor, the primary issue for the Company is that it does not know how much load is returning from Electric Choice until December 1, 2010, which can result in unexpected increases in PSCR expense.

Q. What happens if an existing Electric Choice customer does not provide return to service notification by December 1, 2010 but ultimately returns to full requirements service in 2011?

A. In this situation, the remaining PSCR customers will generally be held harmless because those customers that return to Detroit Edison full electric service in 2011 without providing proper notification will be subject to Market Priced Power (MPP) charges. These charges are designed to offset the

Line No.

incremental cost of serving those customers and will effectively maintain the previously projected average PSCR expense.

During the PSCR plan years of 2006 through 2010, the Company has imposed total MPP charges of more than $8.1 million in the bills of customers who have failed to meet the return to service notification deadlines, failed to meet the minimum stay requirements on Electric Choice service, or failed to commit to the minimum stay on Detroit Edison full electric service upon their return from Electric Choice service.

Q. Has the Company included a credit for MPP charges in its determination of its 2011 PSCR factor?

A. No. The Company does not have the ability to reliably predict the amount of MPP charges that it may ultimately impose on customers' bills in the 2011 PSCR Plan year. In addition, the MPP charges imposed on customers who did not provide proper notice, did not meet the minimum stay on Electric Choice, or did not commit to the minimum stay on Detroit Edison full electric service, will be used to hold the balance of the PSCR customers harmless from the actions of those customers by simply offsetting the increased power supply costs the Company incurs due to their actions.

Q. How do Exhibits A-3 and A-4 reflect the development of the PSCR Factor?

A. The Power Supply Costs (adjusted for R-10, other interruptible sales, and third party wholesale sales) shown on Line 1 were obtained from Witness

Line No.

Wojtowicz's Exhibit A-13, page 1 of 1, Line 46. The Projected Prior Year PSCR over/(under) collection shown on Line 2 is the Company's current projection of its prior year PSCR position for all customers. The Total Power Supply Costs shown on Line 3 is the addition of the projected power supply costs reflected on Lines 1 and 2. Net System Requirement (adjusted for R-10, other interruptible sales and third party wholesale sales) shown on Line 4 was obtained from Witness Wojtowicz's Exhibit A-13, page 1 of 1, Line 45. This Net System Requirement value reflects an Electric Choice forecast for 2011 of 4,987 GWh based upon Witness Siefman's Exhibit A-11.

The Unit Cost of Power Supply shown on Line 5 is the result of dividing the Total Power Supply Costs (adjusted for R-10, other interruptible sales and third party wholesale sales) shown on Line 3 by the Net System Requirement (adjusted for R-10, other interruptible sales and third party wholesale sales) shown on Line 4.

The Base Unit Cost shown on Line 6 and the Loss Multiplier shown on Line 8 are those approved by the Commission in the January 13, 2009 Order in MPSC Case No. U-15244.

The Unit Cost Above (Below) Base shown on Line 7 is the difference between the Unit Cost of Power Supply shown on Line 5 and the Base Unit Cost shown on Line 6.

The PSCR Factor shown on Line 9 of (2.98) mills/kWh is the product of the Unit Cost Above (Below) Base and the Loss Multiplier shown on Line 8.

Q. Does the product of the Unit Cost Above (Below) Base and the Loss Multiplier increase the amount of expense that the Company is collecting from its PSCR customers?

A. No. This product simply converts the amount of power supply expense recoverable on a net system requirement basis to the amount of power supply expense on a sales basis. Because the Company recovers its forecast expense from customers on a sales basis, this is a necessary conversion for billing purposes. This calculation is consistent with the methodology first approved by the Commission for Detroit Edison's 1983 PSCR Plan and has been approved by the Commission consistently in all PSCR plan years.

Q. If the loss factor approved by the Commission exceeds actual losses and allows the Company to collect revenue in excess of actual expense, how would the PSCR customer be held harmless?

A. The PSCR reconciliation for the subject plan year will compare actual expense to actual revenue and will serve to ensure that any over-collection of power supply revenue is returned to PSCR customers with interest at Detroit Edison's approved return on common equity. The currently approved return on common equity for Detroit Edison is 11%.

Q. Do you have any clarifications to make with respect to the PSCR

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Factor that is presented?

A. Yes. In the event the Company's next general electric rate case is filed such that its projected test period overlaps the 2011 PSCR Plan period and reflects a urea expense different from that currently approved for recovery in non-fuel base rates, Detroit Edison will make appropriate adjustments to the incremental urea expense in order to reflect the final order in that matter.

Q. How will the Company ultimately reconcile the amounts collected to recover any actual 2010 PSCR over/(under) recovery?

A. Detroit Edison will reconcile the amounts collected with the actual over/(under) recovery amount within the applicable annual PSCR Reconciliation filing. For instance, if Detroit Edison applied a surcharge to its PSCR customers' bills for a projected 2010 PSCR under-collection during 2011, Detroit Edison would reconcile the actual amounts collected during 2011 with the actual 2010 reconciliation amount ordered in the 2010 PSCR reconciliation in its 2011 PSCR Reconciliation proceeding. The Company would amortize the 2010 PSCR under-collection amount throughout 2011, or as otherwise ordered, and ultimately reconcile any differences between the actual amount collected, including appropriate interest, and the actual amount ultimately found to be reasonably and prudently incurred in its 2010 PSCR Reconciliation proceeding.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
THE DETROIT EDISON COMPANY	)	
for Authority to Implement a Power	)	Case No. U-16434
Supply Cost Recovery Plan in its	)	
Rate Schedules for 2011 Metered	)	
Jurisdictional Sales of Electricity	)	

EXHIBITS

OF

KENNETH D. JOHNSTON

Detroit Edison Company
Power Supply Cost Recovery Factor
Forecast Period January 2011 through December 2011

Line No.		(a) 2011	
1	2010 Power Supply Costs (adjusted for R10, other interruptible & third party sales)	$1,206,927	
2	Projected Prior Year PSCR (over)/undercollection	$36,349	
3	Total Power Supply Costs	$1,243,275	
4	Net System Requirement (adjusted for R10, other interruptible & third party sales)	43,669	GWh
5	Unit Cost of Power Supply	28.47	Mills/kWh
6	Base Unit Cost	31.26	Mills/kWh
7	Unit Cost Above (Below) Base	(2.79)	Mills/kWh
8	Loss Multiplier	1.068	
9	PSCR Factor	(2.98)	Mills/kWh

('$000' omitted)

Detroit Edison Company
Power Supply Cost Recovery Factor
Forecast Period 2012 through 2015

Line No.		2012	2013	2014	2015	
1	Forecast Year Power Supply Costs (adjusted for R-10, other interruptible & third party sales)	$1,392,771	$1,500,505	$1,516,502	$1,564,545	
2	Projected Prior Year PSCR (over)/undercollection	$0	$0	$0	$0	
3	Total Power Supply Costs	$1,392,771	$1,500,505	$1,516,502	$1,564,545	
4	Net System Requirement (adjusted for R-10, other interruptible & third party sales)	44,049	43,979	43,797	43,340	GWh
5	Unit Cost of Power Supply	31.62	34.12	34.63	36.10	Mills/kWh
6	Base Unit Cost	31.26	31.26	31.26	31.26	Mills/kWh
7	Unit Cost Above (Below) Base	0.36	2.86	3.37	4.84	Mills/kWh
8	Loss Multiplier	1.068	1.068	1.068	1.068	
9	PSCR Factor	0.38	3.05	3.59	5.17	Mills/kWh

('$000' omitted)

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
THE DETROIT EDISON COMPANY	)	
for Authority to Implement a Power	)	Case No. U-16434
Supply Cost Recovery Plan in its	)	
Rate Schedules for 2011 Metered	)	
Jurisdictional Sales of Electricity	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MICHAEL W. SHIELDS

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF MICHAEL W. SHIELDS

Line
No.

Q. What is your name, business address and who are you testifying on behalf of?

A. My name is Michael W. Shields. My business address is: DTE Energy, One Energy Plaza, Detroit, Michigan 48226. I am testifying on behalf of The Detroit Edison Company (Company or Detroit Edison).

Q. What is your present position?

A. I am the Manager – Wholesale Market Developments, Regulatory Affairs.

Q. Would you please describe your educational background?

A. I received a Bachelor of Science Degree in Nuclear Engineering from North Carolina State University in 1973. I received a Masters of Business Administration Degree from the University of Michigan in 1983.

Q. Would you please describe your professional experience?

A. Following graduation from North Carolina State University in the spring of 1973, I was employed by Carolina Power & Light Company during the pre-operational and power ascension testing programs for the Brunswick 1 & 2 nuclear units in Southport, North Carolina.

I began my employment with The Detroit Edison Company in 1978 as the Assistant Reactor Engineer assigned to the Fermi 2 nuclear power plant. I was later promoted to the site Startup Testing Engineer and Reactor Engineer.

Line No.

In 1987, I transferred to the Resource Planning group in the Generation Planning Department. In this department I was responsible for numerous economic and planning studies associated with the Company's resource planning process, and was later made responsible for the overall coordination of the development of the Company's Integrated Resource Plans. In 1994, I was promoted to the position of Senior Integrated Resource Planning Engineer, assuming increased responsibilities over the Integrated Resource Planning and long-term Fuel Forecasting areas. I was also responsible for developing the Corporate long-term emission allowance program.

In 1996, the Resource Planning group was merged with the Customer Energy Solutions -- Sourcing (Formerly Power Supply Transactions - Operations) function. In the Sourcing group, my primary responsibility continued to involve the development of long-term fuel and resource planning projections using computer simulation models. Such studies evaluated long-term power purchases or sales, requests for proposals, and long-term marginal costs. I also continued to be responsible for studies in support of the Company's long-term sulfur dioxide (SO_2) compliance planning. I later also became involved with planning for and procuring the Company's summer capacity needs.

In 2001, I was promoted to Manager – Long Term Sourcing, Generation Optimization. My areas of responsibility included directing the procurement of Detroit Edison's summer capacity and transmission requirements. I was also responsible for the coordination of any month or longer sales or purchases made for Detroit Edison and for any emissions credit purchases and sales made on behalf of Detroit Edison.

In my current position I am working directly with the Midwest Independent Transmission System Operator (MISO) in support of Detroit Edison's participation in the MISO Energy and Ancillary services Markets. In this role I work with various groups in the Company in developing bidding strategies for the MISO markets, supporting market settlement issues, and in coordinating the Company's involvement with all types of MISO-related activities.

I have participated on many of the MISO stakeholder committees, subgroups, and working groups and have also attended numerous Merchant-related MISO training sessions, which are intended to familiarize people with the MISO Markets. In May 2007, I was elected by MISO stakeholders to be the Chair of the MISO Market Subcommittee, which is one of the major stakeholder committees dealing with MISO market-related issues, and I served in that capacity until May 2009.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission?

A. Yes. I supported and/or sponsored testimony in the following cases:

U-15677-R	2009 PSCR Reconciliation
U-16047	2010 PSCR Plan
U-15417-R	2008 PSCR Reconciliation
U-15244	Detroit Edison's general electric rate case

U-15677	2009 PSCR Plan
U-15417	2008 PSCR Plan
U-15002-R	2007 PSCR Reconciliation
U-15002	2007 PSCR Plan
U-14838	Commission’s show cause
U-14702-R	2006 PSCR Reconciliation
U-14702	2006 PSCR Plan
U-14275-R	2005 PSCR Reconciliation
U-14275	2005 PSCR Plan
U-12121	2000 PSCR Plan
U-11175	1997 PSCR Plan

Line No.

Q. What is the purpose of your testimony in this proceeding?

A. The primary purpose of my testimony is to present Detroit Edison's projected expenses associated with being a network transmission customer of ITC *Transmission* (ITC) and with being a Market Participant of the Midwest Independent Transmission System Operator (MISO).

All of these MISO/transmission expenses are required in order for Detroit Edison to serve the anticipated Detroit Edison full service customer load requirements from the MISO Energy Market and the MISO Ancillary Services Markets (ASM). My testimony will address the projected expenses for the period 2011 through 2015. I am dividing my testimony covering these expenses into two sections. The first section discusses the Base Transmission related charges for Detroit Edison. The second section discusses the charges associated with Detroit Edison's participation in the MISO Energy and Ancillary Services Markets.

Q. Are you supporting any exhibits?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-5	MISO Transmission, Energy and Ancillary Services Markets Expense Projections for Years 2011-2015
A-6	MISO Settlement Statement Charges/Credits
A-7	MISO Settlement Statement Charges/Credits Projections for Years 2011-2015

Line No.

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. What is the purpose of Exhibit A-5?

A. Exhibit A-5 presents the Company's projected 2011 through 2015 network transmission expense items and MISO Energy Market and Ancillary Services Market Cost items. Schedules 1, 2, 9, 10, 10-FERC, 16, 17, 24, and 26 are transmission and ancillary service schedules for transmission service under the MISO Transmission, Energy and Operating Reserve Markets Tariff (MISO Tariff or Tariff) as filed with the Federal Energy Regulatory Commission (FERC). Later in my testimony, I will discuss these schedules and the other MISO Energy Market and Ancillary Services Market Cost items in greater detail.

Q. What is the purpose of Exhibit A-6?

A. The line items on Exhibit A-6 reflect the actual line items included on a typical MISO Settlement Statement associated with the charge types used for the MISO Energy and Ancillary Services Markets. As a MISO network customer and Market Participant, each of these MISO charge types represent non-bypassable charges to Detroit Edison. The Company is required to purchase each of these services from MISO and/or pay its share of any uplift/participation costs related to the MISO Energy and Ancillary Services Markets.

Q. What is the purpose of Exhibit A-7?

A. Exhibit A-7 reflects the Company's projections of the more significant MISO

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Energy and Ancillary Services Market related charges/credits that are expected to apply for the years 2011-2015. Later in my testimony, I will discuss how these charges/credits were derived from the Detroit Edison data available from the most recent 12 months of the MISO Energy Market and Ancillary Services Markets.

SECTION 1 – BASE TRANSMISSION COSTS

Q. What is the network transmission Schedule 1 expense shown on line 3 of Exhibit A-5?

A. Schedule 1 is the MISO market charge for scheduling, system control and dispatch service provided by MISO as the transmission provider. This service is required to schedule the movement of power through, out of, within, or into a control area and must be purchased by the transmission customer (in this case Detroit Edison) from MISO. The monthly charge for Schedule 1 is the monthly peak demand multiplied by the FERC-approved rate, which is currently $55.7864/MW-Month. I am assuming the current rate will continue through 2011 and then will increase at the Consumer Price Index (CPI) for subsequent years. Using the current rate, I am projecting the cost for Schedule 1 for Detroit Edison to be approximately $5.0 million for 2011.

Q. What is the network transmission Schedule 9 expense shown on line 4 of Exhibit A-5?

A. Schedule 9 describes the MISO network integration transmission service. Each transmission customer taking network service will pay the firm monthly

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zonal rate defined in the MISO tariff for the zone where the transmission customers' load is physically located, which in Detroit Edison's case is the ITC *Transmission* pricing zone. The Schedule 9 ITC zonal rates are determined annually based on a calculation made by ITC using projected ITC costs. These rates are calculated pursuant to Attachment O of the MISO tariff. It should be noted that a small portion (approximately $21/MW-month) of the total Schedule 9 rate paid by Detroit Edison includes a component associated with The Michigan Public Power Agency (MPPA)'s ownership of a small amount of transmission integrated with the ITC system.

The rate for Schedule 9 which will be in effect from January 1, 2011 through December 31, 2011 is $2,525/MW-month. The majority of this rate ($2,504/MW-month) is based upon ITC's 2011 forecast expenses in accordance with its FERC-authorized forward-looking Attachment O rate formula. The remainder of the Schedule 9 rate is the portion related to the MPPA charge as described above.

For the years after 2011, the Company has made an estimate of what the future rates will be by making a projection of ITC's future Operating & Maintenance (O&M) costs and by also projecting the impacts of the changes to the portion of ITC's capital costs intended for equipment replacement and modifications. It should be noted that the cost impacts of much of the ITC planned and proposed future transmission projects will be primarily recovered under Schedule 26 of the MISO Tariff, as discussed later in my testimony. For this reason the additional O&M costs projected for Schedule 9 will be somewhat offset by the ongoing depreciation of the transmission equipment currently included in ITC's rate base. The Company's analysis assumes that future ITC O&M costs will increase at the rate of inflation.

The total Schedule 9 rate applied to the forecasted monthly peak demands is projected to result in approximately $226.6 million of Schedule 9 expense to Detroit Edison to serve its bundled retail customers in 2011.

Q. What is the MISO Schedule 2 Expense shown on line 7 of Exhibit A-5?

A. Schedule 2 is the component of MISO's tariff intended to cover the costs for compensating generators who provide Reactive Supply and Voltage Control services. In past years Detroit Edison was the sole provider for this service in the Detroit Edison service territory. FERC has subsequently specified that Schedule 2 rates should be modified to also compensate Independent Power Producers (IPPs) that are capable of providing these ancillary services within each transmission pricing zone. Thus, a portion of the Schedule 2 rate is based on the FERC-approved revenue requirements to compensate the Wolverine peakers located in Sumpter Township, the CMS Dearborn Industrial Generation plant, and the DTE Energy Services' East China generating units. FERC also approved the Schedule 2 revenue requirements payable to Detroit Edison's generating units for providing Reactive Supply service.

The Schedule 2 tariff rate for the ITC *Transmission* zone is $180.87/MW-month. Since the majority of the funds associated with this rate that are paid by Detroit Edison customers are subsequently returned to Detroit Edison, and given that Detroit Edison is still the largest supplier of Reactive Supply service within the ITC *Transmission* zone, my calculation focuses on the difference in the amount that Detroit Edison customers will pay year over year to the other Reactive Supply providers listed above as opposed to the amount that Detroit Edison will receive from other load serving entities (including Wholesale customers and Retail Choice load). For 2011, this difference between what is paid to other Reactive Suppliers versus what is received by Detroit Edison from other load serving entities is projected to be about $2.2 million, which is the cost shown on line 7 of Exhibit A-5.

It should be noted that in the January 13, 2009 order approving the tariff rate sheets associated with the Company's main electric rate case, Case No. U-15244, the Michigan Public Service Commission authorized that ancillary services costs and revenues, including those associated with Schedule 2, are to be handled through the Power Supply Cost Recovery process. In Case No. U-15244, the Company indicated that with the start of the MISO ASM market in January 2009, it would be more appropriate to include ancillary services revenues as part of the PSCR process, particularly since the fuel and purchased power expense associated with providing these ancillary services were already being included within the PSCR. The provisions of this order are reflected in the cost estimates made for Schedule 2, as discussed above, and for the cost estimates made for certain other ancillary services discussed later in my testimony.

Q. What is the MISO Schedule 10 expense shown on line 10 of Exhibit A-5?

A. MISO Schedule 10 expense is the cost recovery adder under which MISO recovers its cost of operations other than the costs associated with operation of the Financial Transmission Rights (FTR) Market (Schedule 16) and the Energy and Ancillary Services Markets (Schedule 17). There are two components in the calculation of Schedule 10 expense. One component is based on monthly peak demand. The other component is tied to monthly energy usage. The demand charge component is based on the product of monthly peak demand, the hours in the month, and the calculated demand component rate. The energy component is the product of the energy usage each month and the calculated energy component rate.

MISO has projected that the overall Schedule 10 rate for 2011 will be approximately $0.132/MWh. Using the Schedule 10 demand and energy rates projected by MISO, the cost to Detroit Edison to participate in MISO to serve its retail electric customers is expected to be approximately $7.0 million in 2011.

Q. What is the MISO Schedule 10-FERC expense shown on line 13 of Exhibit A-5?

A. The MISO Schedule 10-FERC expense is the cost recovery adder for the recovery by MISO of its FERC assessment fee. This fee is charged by FERC to cover a portion of FERC's operating costs. This charge is also sometimes referred to as the "FERC Assessment" charge. The charge to MISO is based on total megawatt-hours (MWh) of Transmission Service reported each year by MISO on FERC Form 582.

MISO in turn allocates this cost to all MISO transmission customers, including those taking network service, like the Company. The expense is calculated by applying the MISO rate for this schedule to the monthly peak demand multiplied by the hours in the month. Based on rate information provided by FERC, for 2011 the assessment for MISO is estimated to be $0.061 per MWh. For 2011, this charge represents an estimated Detroit Edison expense of $4.0 million.

Q. What are the MISO Schedule 26 Network Upgrade charges involving Transmission cost adders shown on line 16 of Exhibit A-5?

A. MISO, in conjunction with the Regional Expansion Criteria and Benefits (RECB) Task Force, developed a regional cost allocation methodology for new transmission projects intended to improve system reliability (referred to as Baseline Reliability Projects). Under this methodology, commonly referred to as RECB I, the cost of certain new transmission projects is allocated to not only the transmission customer for whom the project is primarily being constructed, but also to adjacent regions or zones that may also receive benefits from the new transmission project. For the RECB I projects FERC approved a cost-sharing mechanism under which 20% of the costs of any new transmission project in MISO built at a voltage level of 345 kV and above are uplifted to all load serving entities (including Detroit Edison) on a MISO-wide basis. The remaining 80% of the costs of the transmission projects built at a voltage level of 345 kV and above are allocated based upon MISO's performance of a Line-Outage-Distribution Factor (LODF) analysis to determine the beneficiaries of a particular project.

MISO's RECB I cost sharing methodology will allocate 100% of the costs of transmission projects built at voltage levels between 100 kV and 345 kV, based on the results of the LODF analysis.

MISO uses Schedule 26 as the mechanism for collecting the charges for all new transmission projects that are eligible for regional cost sharing as defined in Attachment FF (Transmission Expansion Planning Protocol) of the MISO Tariff. This includes all new transmission projects that are at voltage levels of 100 kV or greater that have a project cost greater than $5 million (including the costs borne by the Transmission Owners in developing a Generation Interconnection Project). For Generator Interconnection Projects other than those developed by the ITC Holdings Operating Companies and those developed by the American Transmission Company (ATC), currently 10% of the cost is borne by the Transmission Owner, and the remainder is borne by the Generation Project developer. The 10% cost allocation borne by the Transmission Owner will be allocated regionally in the same manner as discussed above for use with Baseline Reliability Projects.

In a FERC order issued on October 23, 2009 (Docket No. ER09-1431), FERC authorized the ITC Holdings Operating Companies and ATC to charge its customers for the cost component that would have otherwise been charged to the Generation Project developer under Attachment FF of the MISO Tariff, with all of the other provisions of Attachment FF remaining the same.

MISO currently provides forecast information that can be used to calculate the Schedule 26 rates by transmission pricing zone. I have used this information as provided for the ITC *Transmission* zone to calculate the projected Schedule 26 costs for Detroit Edison as shown on line 16 of Exhibit A-5. As part of the calculation, I have adjusted the Schedule 26 cost estimates provided by MISO to reflect the fixed charge rate value for ITC. The cost for Schedule 26 for 2011 is projected to be $19.9 million.

It should be noted that the Schedule 26 projection includes not only the costs to be allocated to Detroit Edison retail customers in the ITC *Transmission* pricing zone related to new projects being developed by MISO transmission owners outside of the ITC *Transmission* zone, but also includes the cost allocation of new ITC projects to ITC customers for those projects that qualify for regional cost sharing as defined above.

Q. Are there any other categories of transmission projects the costs of which will be recovered through MISO Schedule 26 Network Upgrade shown on line 16 of Exhibit A-5?

A. Yes. First, there is another category of transmission projects under the Attachment FF of the MISO Tariff currently referred to as Regionally Beneficial Projects, which are those projects determined by MISO to have significant regional <u>economic</u> benefits that cannot be justified solely as being necessary to meet regional reliability requirements. These projects are commonly referred to as RECB II projects. FERC issued an order on March 15, 2007 essentially adopting the cost allocation proposal recommended by MISO. To date, there has been very little activity within MISO associated with RECB II projects. However, if RECB II projects should be approved in the future, then their costs can also be allocated regionally under Schedule 26.

In addition, on July 15, 2010 (Docket No. ER10-1791) MISO made a filing to FERC proposing the creation of a new category of transmission projects referred to as Multi Value Projects (MVPs), which are primarily intended for use in addressing state and federal renewable energy legislation. To date, FERC has not issued an order on this proposal. The MISO filing proposes that the cost of MVP projects be allocated to load and exports on a MWh basis, which will ultimately be handled under a new MISO tariff schedule, Schedule 26-A.

In anticipation of a future FERC order supporting the MVP project concept, in August 2010, the MISO Board approved a project submitted by ITC *Transmission* (commonly referred to as the "Thumb Loop" project) that is being proposed based upon Michigan's renewable energy legislation. At this time, pending the FERC approval of the MVP project concept, the Thumb Loop project is being included as part of the Schedule 26 cost allocation values provided by MISO. However, the Schedule 26 data provided by MISO do not reflect any cost impacts resulting from the Thumb Loop project until 2015.

More information with regards to the Multi Value Project filing and the Thumb Loop project is provided in the testimony of Mr. Musial.

Line
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Q. What is the Total Base Transmission Cost shown on line 19 of Exhibit A-5?

A. The Total Base Transmission Cost is the sum of the charges for Schedules 1, 2, 9, 10, 10-FERC, and 26. For 2011, I estimate this cost to be approximately $264.8 million, which is necessary to serve Detroit Edison's full service retail customers. The bulk of this amount ($226.6 million) represents the ITC *Transmission* Zone charges associated with network service.

SECTION 2 - MISO ENERGY and ANCILLARY SERVICES MARKETS CHARGES & CREDITS

Q. How was Detroit Edison affected by the start of the MISO Energy Market?

A. The MISO Energy Market commenced operations on April 1, 2005. MISO operates both day-ahead and real-time spot wholesale energy markets centered on the use of locational marginal price (LMP) models to calculate the total power costs at defined locations by taking into account not only energy costs but also the cost of congestion and marginal losses for each location. MISO also provides energy balancing and congestion management services for the entire MISO footprint.

Each day, Detroit Edison "offers" its generating resources into the MISO Energy Market and also "bids" in its projected load. In effect, Detroit Edison purchases through the MISO Energy Market the energy needed to serve its load at the market clearing LMP calculated for Detroit

Line No.

Edison's load. Likewise, energy from Detroit Edison generation resources is sold into the MISO market at the LMP calculated for each Detroit Edison generator bus. MISO determines which generators are the most economic to serve load within the MISO Energy Market and provides start, stop, and dispatch information and instructions for the selected generators.

Q. How was Detroit Edison affected by the start of the MISO Ancillary Services Market?

A. The MISO Ancillary Services Market (ASM) commenced operations on January 6, 2009. MISO operates both day-ahead and real-time spot wholesale markets to provide the ancillary services formally provided under the Schedule 3 (Regulation and Frequency Response); Schedule 5 (Operating Reserve – Spinning Reserve) and Schedule 6 (Operating Reserve – Supplemental Reserve) cost-based tariffs. As stated previously in my testimony, Schedule 2 (Reactive Supply and Voltage Control from Generation Sources) service continues to be provided under a cost-based tariff calculated for each transmission pricing zone, and therefore is not part of the Ancillary Services "market" design that is now being used to provide regulation and operating reserves in MISO.

Each day, Detroit Edison "offers" its capability to provide these ancillary services to the MISO ASM markets. Each day, Detroit Edison load is assessed a portion of the costs incurred by MISO to procure ASM services, on a load ratio share basis. MISO determines which generators are the most economic to provide the ancillary services within the MISO ASM market and provides the necessary dispatch signals to those generators.

Q. What is a Financial Transmission Right?

A. In the MISO Energy Market one component of the LMP calculation is the cost of relieving any transmission congestion. A Financial Transmission Right (FTR) is a financial instrument that gives transmission customers such as Detroit Edison the potential to protect against the costs associated with transmission congestion.

The Company is allocated some level of FTRs/ARRs as part of an annual MISO FTR/ARR allocation process. Starting in 2008, the annual allocation actually involves Auction Revenue Rights, or ARRs. However, following the allocation or the purchase of an ARR, there are provisions to “self-schedule” ARRs into FTRs, with the FTR continuing to serve the same function as described previously. For the remainder of my testimony, I will just make reference to FTRs, since this is the end result of being allocated or purchasing an ARR and “self-scheduling’ the ARR to convert it to a FTR.

The FTR allocation amount may vary for each season, and for the off-peak and on-peak periods. However, even after the FTR allocation occurs, it is still likely that the Company could continue to be exposed to congestion charges in the event of generation outages, transmission outages, or other events not captured in the allocation modeling. Additionally, the Company has not historically received all of the FTRs it has requested for each season in the allocation process.

Conceptually, the rights associated with FTRs are similar to a Physical Transmission Right. Both are booked costs and are a necessary and integral part of purchased and net interchange power transactions.

Q. What is the MISO Schedule 16 expense shown on line 23 of Exhibit A-5?

A. The MISO Schedule 16 expense is the Financial Transmission Rights Administrative Service Cost Recovery Adder. The monthly expense is calculated by multiplying the FTR Administrative Cost Recovery Adder rate by the total MWs of FTRs held by the transmission customer (in this case, Detroit Edison). According to MISO, the average rate for 2011 is projected to be $0.017/FTR-MWh, which is multiplied by the number of hours in each month to obtain the monthly cost.

Assuming that the Company is able to obtain its full entitlement in the 2011 MISO FTR allocation, I anticipate that Detroit Edison will hold, at a minimum, sufficient FTRs to cover the Company's peak summer demand minus the reduction required by MISO for the Ludington Grandfathered Agreement (GFA). Based upon this assumption, I estimate that Detroit Edison will incur approximately $1.4 million of Schedule 16 expense in 2011.

Q. What is MISO Schedule 17 expense shown on line 26 of Exhibit A-5?

A. The MISO Schedule 17 expense is the Energy Market Support Service Cost Recovery Adder. This service will be provided by MISO to all transmission customers and other MISO Market Participants that participate in transactions using the transmission system and/or using the day-ahead or real-time energy markets. According to MISO, the expected Schedule 17 rate for 2011 will be $0.095/MWh. This adder is applied to: 1) all MWh injected into the transmission system by all system participants, including deliveries to the transmission system from generation located within the transmission system and from imported energy coming in from sources outside the transmission system, 2) all MWh extracted from the transmission system by all system participants under point-to-point or network integrated transmission service, including MWh delivered to loads both within the transmission system and exported outside of the transmission system, and 3) all physical and/or virtual bids or offers that settle in the day-ahead market, but do not actually inject MWh into or extract MWh from the transmission system in the real-time market. Detroit Edison's portion of the Schedule 17 expense to cover MISO's costs associated with the operation of the Energy Market is projected to be approximately $9.0 million for 2011.

Q. What is the MISO Schedule 24 Balancing Authority Charge shown on line 29 of Exhibit A-5?

A. MISO has established a separate Schedule to allow Local Balancing Authority (LBA) entities (such as ITC) to recover the costs incurred as a result of their performance of the balancing functions and provision of other MISO Energy market services as required under the Balancing Authority Agreement with MISO. MISO adds up all the expense associated with LBA operations across the MISO footprint and uplifts this expense to MISO Market Participants based on their levels of energy injections and withdrawals in the day-ahead and real-time energy markets, in a manner similar to that used for assessing the Schedule 17 Energy Market charges.

Included in the total Schedule 24 costs are the costs associated with the operation of the Michigan Electric Coordination System (MECS) LBA that is operated by ITC. For 2011, I am estimating the average Schedule 24 rate to be about $0.0120/MWh, which was calculated based on the average of the historical monthly rates from October 2009 through September of 2010. I am projecting the total Schedule 24 expense to Detroit Edison for 2011 to be about $1.1 million.

Q. What are some of the other costs and/or credits that will be incurred by Detroit Edison's participation in the MISO Energy and Ancillary Services Markets?

A. Other costs that will be incurred by Detroit Edison include: 1) Costs (and credits) associated with the use of Marginal Loss Pricing in calculating LMP costs paid by Load Serving Entities (LSEs) such as Detroit Edison, 2) Costs (and credits) associated with congestion for LSEs, 3) Miscellaneous uplift/participant charges and credits that MISO will impose on all Market Participants under defined circumstances, and 4) ASM costs netted against

ASM revenues.

Q. What is meant by MISO uplift/participant charges and how can they impact the costs for the Company and its full service customers?

A. MISO, by design, is intended to be “revenue-neutral” with regards to the operation of the MISO Energy Market. To accomplish this revenue neutrality, MISO seeks to ensure that all costs/credits for each hour are uplifted among the appropriate Market Participants. In general, where MISO can pinpoint the Market Participants that have caused additional costs to be imposed on the market as a result of some action they have taken, these costs are assigned to that Market Participant. However, certain other charges/credits that occur in the market are considered to result from the inherent structure of the market itself, and these are typically uplifted by MISO to all Market Participants on a load weighted basis. In particular, many of the charges and credits associated with Grandfathered Agreements (GFAs) fall into this category, as GFAs are given special treatment by MISO due to the historical and long-term nature of these agreements.

On Exhibit A-6 and Exhibit A-7, I show all the various charges/credits that are calculated by MISO related to the MISO Energy and ASM Markets. I will explain some of the more significant charges/credits that are likely to be experienced in 2011 based on current MISO Energy and ASM Market information.

Q. What does Exhibit A-6 illustrate?

A. Exhibit A-6 is in the format of an actual MISO Summary Settlements Statement. It contains all the charge types directly related to participation in the MISO Energy and ASM Markets. Under the MISO settlements process, the first set of billing information is received seven days after each operating day (referred to as the S-7 statement). Updates to the initial settlement statement are made 14, 55, and 105 days after each operating day. At times, statements are issued for periods past 105 days as a result of certain "resettlements" performed by MISO to comply with certain rule changes and/or to correct errors made in calculations reflected on previous settlements. These "resettlement" periods end once all the corrections are made for all to cover all the applicable past operating days. More information is available relative to the various charge types, how they are calculated, and on the overall settlement process, in the "MISO Business Practice Manual for Market Settlements" available on the www.midwestiso.org web site under the "Documents" tab.

There are basically three categories of charge types and fifty-five individual items represented in the settlement statement summary. The charge type categories are the Day-Ahead (DA) charge types associated with the MISO Day-Ahead market; the Financial Transmission Rights (FTR) Charge types associated with allocation, procurement, and revenues associated with holding FTRs in the Day-Ahead market; and the Real-Time (RT) Charge types associated with the Real-Time energy market. In order to provide clarification for my cost estimates I will be separating out the charge types related to the Ancillary Services Markets even though they are listed under the DA and RT categories.

Q. What does Exhibit A-7 illustrate?

A. Exhibit A-7 includes certain charge type items that represent some of the more significant MISO Energy and Ancillary Service Market charges that have not been accounted for elsewhere in other cost/credit estimates. I have developed Detroit Edison's future cost/credit estimates for these charges based on the actual MISO billing data for the most recent twelve months (September 1, 2009 – August 31, 2010) of the MISO Energy Market and ASM Markets.

On Exhibit A-7, I am combining some of the related charge types that I have determined to be similar in nature from Exhibit A-6 to develop cost/credit projections for 2011 and beyond. In reviewing Exhibit A-7, it is important to understand the MISO sign convention for the charge types represented on a MISO Settlement Statement. A positive value represents money that is owed to MISO, and a negative value represents money owed to Detroit Edison.

Q. What is the Net Revenue Sufficiency Guarantee and Make Whole Payments item on Exhibit A-5, line 32?

A. The RT Revenue Sufficiency Guarantee (RSG) First Pass Distribution Amount represents the added costs incurred by Detroit Edison when there is a load or generation deviation in the Real Time market as compared to what the Company projected in the Day Ahead market. This charge is similar to the real-time "premium" (i.e. increased costs) Detroit Edison paid prior to the existence of the MISO Energy Market in the balance-of-day or hourly marketplace if a Company generation unit tripped off line and it was necessary to procure additional energy from another source on short notice. On the credit side, the RT Revenue Sufficiency Guarantee Make Whole Payment Amount and the RT Price Volatility Make Whole Payment represent payments made to Detroit Edison when the Company's units (primarily peakers) are called upon by MISO to cover some unexpected load increase or loss of generation within the MISO footprint. When MISO calls on these units to run on short notice, MISO "guarantees" that they will fully recover their startup, no-load, and energy costs.

While much smaller in magnitude, there are Day Ahead counterparts to the Real Time RSG charges and RSG make whole payments. With the DA Revenue Sufficiency Guarantee Distribution Amount and the DA Revenue Sufficiency Guarantee Make Whole Payment Amount charge types, each generator that offers into the Day Ahead market and is selected by MISO is guaranteed full recovery of its startup, no-load, and energy offer. Unlike the Real Time RSG Make Whole Payment, the Day Ahead RSG Make Whole Payment is uplifted to all LSEs that bid load into the Day Ahead Market.

The net impact of these five charge types for the most recent 12 months (September 1, 2009 to August 31, 2010) of the MISO market is a credit to

Line
No.

Detroit Edison of about $12.3 million. This amount is being used as the basis for my projection for 2011 and beyond, as shown on line 11 of Exhibit A-7 and on line 32 of Exhibit A-5.

Q. How will Detroit Edison's full service retail customers be impacted by MISO congestion costs?

A It is unlikely that the Company can fully protect its customers against all of the congestion that will be experienced in the MISO Energy Market, even with the purchase of additional FTRs. First of all, in previous attempts to obtain FTRs during the MISO allocation process, Detroit Edison has not been allocated all of the FTRs that it requested due to certain identified transmission constraints located both within MISO and external to MISO. MISO runs a simultaneous feasibility model to determine the percentage of the FTRs requested by all parties that can feasibly be awarded, and will only allocate the level of FTRs requested by each party when the total allocation to all parties will pass the "simultaneous feasibility" test. For certain long-term FTR entitlements a payment will be made to cover the shortfall identified in the simultaneous feasibility test, but that shortfall MW quantity cannot be "self-scheduled" to represent an ongoing FTR right.

Even after FTRs are awarded as a result of the annual allocation there is still no assurance that the FTRs will be fully funded for each month or for the entire year, as there may be differences in the assumptions used in the simultaneous feasibility model and what actually occurs in terms of regional loads, loop flows, and generation & transmission outages that can create

Line No.

congestion.

Another important point is that the FTRs allocated by MISO will be in the form of FTR obligations. This means that the Company is only protected by the FTR if the congestion component of the LMP at the defined sink location is higher than the congestion LMP component value at the defined source location, assuming some level of congestion exists in the transmission system. Each FTR is directional, typically defined from a specific supply source to a load sink – Detroit Edison's Monroe Unit 1 to Detroit Edison load is an example of a FTR that Detroit Edison will typically obtain during the annual allocation process.

However, because each FTR is directional, the FTR holder will have to pay the LMP congestion component between the defined FTR sink and source should the opposite congestion situation occur and the LMP value at the source location become higher than the LMP value at the sink location due to congestion, even if only for a short period of time,. This "LMP reversal" situation could occasionally occur in localized areas as a result of transmission and/or generation outages, and also as a result of increased imports and/or exports crossing through the ITC *Transmission* system. As discussed later in my testimony, I make an estimate of the value of the Company's FTRs to protect against congestion costs based on our experience over the last twelve months in the MISO Energy Market.

Line No.

Q. How was the Net Congestion Cost value included on Exhibit A-5, line 35 derived?

A. As can be seen under the heading "Congestion Calculation" in Exhibit A-7, the Company is using the most recent 12 months (September 1, 2009 to August 31, 2010) of historical MISO Energy Market information to develop a projection for 2011 and beyond.

The first item in the "Congestion Calculation section, "Congestion Amount between Generation and Load", reflects the net differential congestion costs between Detroit Edison generation and load. For example, in June 2010 the difference in the monthly average congestion cost component of the LMPs between the Monroe Unit 1 generation node and the Detroit Edison DECO.NEC load node was $0.046/MWh (DECO.NEC is the name of the commercial price or "CP" node representing the load-weighted LMPs calculated for all the MISO defined elemental pricing nodes in the ITC footprint). If the Monroe Unit 1 generated 500,000 megawatt hours during this month, then Detroit Edison load would have paid $23,000 more in congestion costs than would have been received in the congestion component of LMP payments for the Monroe Unit 1. In the final analysis, some of that congestion cost will be offset by FTR credits, as I explained previously.

To make an estimate of the 2011 congestion costs, I start with the actual monthly averages of the hourly congestion cost differences between each Detroit Edison generating unit on the Detroit Edison system and the Detroit Edison DECO.NEC load CP node, such as the $0.046/MWh value used in the above example for Monroe Unit 1 for June, 2010. Then, using the projected generation information for each Detroit Edison unit as provided by Detroit Edison Witness Ms. Wojtowicz, I multiply the net MWh supplied by each Detroit Edison generation unit for each month times the congestion cost differences determined from historical information. That number is then reduced by the ratio of the monthly forecasted load to the monthly forecasted generation for months where the monthly load forecast is less than the Detroit Edison generation forecast to account for the generation MWh used to supply transmission losses, as will be discussed later in more detail. The net cost determined in this manner is my estimate for the "unadjusted" congestion costs associated with Detroit Edison generation, which leads to the projected cost of $3.5 million shown on Exhibit A-7, line 15 for 2011.

Also shown on Exhibit A-7 are the actual congestion costs/credits charge types associated with the historical purchases and sales made in the most recent 12 months (September 1, 2009 to August 31, 2010) of the MISO Energy Market, shown as Day-Ahead and Real Time Financial Bilateral Transaction Congestion Amounts, and the Day Ahead and Real Time congestion rebates associated with our Carve-out GFA (Ludington). In addition, the net of the credits/charges associated with holding FTRs during this period are shown on lines 20 through 29 of Exhibit A-7. I believe that the net value of all these items, a credit to Detroit Edison of $6.3 million, provides a reasonable estimate of the congestion costs net of any FTR offset and auction credits and net of the real time congestion costs discussed below. This value is shown on line 31 of Exhibit A-7 and is included as line item 35 on Exhibit A-5 to reflect this cost estimate for 2011.

Q. What other congestion charges, if any, are not captured in the above calculation?

A. Starting in mid-September 2005, MISO decided to collect the shortfall dollars through the use of the Revenue Inadequacy component of the Real Time Revenue Neutrality charge type because of a consistent shortfall in the collection of real-time congestion costs. With this change, the Detroit Edison costs related to these congestion costs are not specifically known. However, for this proceeding I am capturing the effects of these costs by including the RT Revenue Neutrality Uplift Amount as a separate item as discussed later in my testimony.

Q. What are Marginal Losses and how does their use for dispatch purposes impact Detroit Edison's power supply costs?

A. In the past, Detroit Edison self-supplied the energy needed to cover transmission line losses. With the initiation of the MISO Energy Market in 2005, transmission line losses are inherently handled within the LMP calculation. MISO will calculate the marginal cost of transmission losses as part of the overall LMP calculation at each load node. The marginal losses component of LMP at any market node reflects the transmission systems' real energy losses associated with each additional MWh of consumption by load.

Because the losses are charged based on a “marginal” cost versus an “average” cost basis, it is inherent within the calculation methodology that MISO will be over-collecting revenues associated with transmission line losses. MISO has developed a mechanism to return over-collected transmission line loss revenues to each LSE, such as Detroit Edison, on a load weighted basis.

To estimate the cost impacts of marginal losses, I used the same methodology employed in determining congestion costs. A reasonable estimate of the marginal losses costs can be determined by looking at the monthly average of the hourly differences between the LMP marginal losses paid by the DECO.NEC load and the marginal losses component received by each generator in its LMP payments, multiplied by the monthly Megawatt-hour output for the generator. In the same manner as was done with the congestion calculation, the number is then reduced by the ratio of the monthly forecasted load to the monthly forecasted generation for months where the monthly load forecast is less than the Detroit Edison generation for each generator, in order to take out the generation needed to cover transmission line losses. By determining the difference in these values for the 12 month period from September 1, 2009 to August 31, 2010, and multiplying that difference by the projected net generator Megawatt-hour output for each month in 2011, I have estimated the total marginal losses amount between the generators and the load to be $46.7 million for 2011, as shown under the “Losses Calculation” heading in Exhibit A-7, line 35. Also shown under this heading are the marginal loss costs associated with purchases and or sales (DA and RT Financial Bilateral Transaction Loss Amounts) and Detroit Edison's Carve-Out GFA (DA and RT Loss Rebate on Carve-out GFA). The next charge type included in this category is the "RT Distribution of Losses Amount," which reflects the refunds made by MISO based on their estimate of the over collection of the costs associated with transmission line losses due to the use of a marginal loss calculation as part of the LMP calculation.

One other credit that is shown under the "Losses Calculation" on line 44 of Exhibit A-7 is an estimate of the Revenue for Transmission Losses. The Revenue for Transmission Losses item is intended provide a rough estimate of the credit due to Detroit Edison as a result of generating energy to cover the transmission line losses within the ITC zone. Conceptually, if a system has 1% transmission line losses, then 101 MW of generation would be needed to supply 100 MW of load as measured at the substation levels where the transmission system connects to the distribution system. I am treating the extra 1 MW of generator revenues (when multiplied times the generator LMPs) in this example as an additional PSCR credit that has not been captured elsewhere in my projections.

To approximate the Revenue for Transmission Losses, I start with the assumption that 1.29% of the total output from Detroit Edison generation is used to supply transmission line losses, which was a value previously provided by MISO to represent the average transmission line losses for the

ITC *Transmission* system. This is only an approximation, as in fact the actual losses vary each hour depending on system load and what generation units are running for that hour. However, on an average basis, this is a reasonable value.

I then multiply the forecasted monthly generation output times the monthly average LMP values for each Detroit Edison generation unit. This calculation led to a projected credit to Detroit Edison of $23.5 million for 2011, as shown on line 44 of Exhibit A-7.

The net cost for losses in 2011, as shown on line 46 of Exhibit A-7 and as carried over to line 38 of Exhibit A-5 is $4.7 million.

Q. What is the RT Revenue Neutrality Uplift item on Exhibit A-5, line 41?

A. The RT Revenue Neutrality Uplift Amount is intended by MISO to be a "catch-all" category for use when the total revenues paid by MISO for each hour for all the other items did not balance against the receipts for that hour. There are actually seven different charges and credits included in the generic "Revenue Neutrality Uplift" charge type. These are:

1) Real Time Contingency Reserve Deployment Failure Charge Uplift Amount
2) Revenue Inadequacy Uplift
3) Joint Operating Agreement (JOA) Uplift
4) Option B Grandfathered Agreement Financial Bilateral Transaction Congestion Rebate Distribution Amount Uplift

5) Real-Time Revenue Sufficiency Guarantee Make Whole Payments Second Pass Distribution Uplift
6) Carve-Out Grandfathered Agreement Congestion Rebate Distribution Amount Uplift
7) Real Time Price Volatility Make-Whole Payment Uplift

For the last twelve months of the MISO Energy Market (September 1, 2009 to August 31, 2010) the RT Revenue Neutrality Uplift Charge was approximately $6.5 million. The Company is using that same value in projecting the cost to Detroit Edison for 2011 and beyond, as shown on Exhibit A-5, line 41.

Q. What are the MISO ASM & Misc. Costs shown on line 44 of Exhibit A-5?

A. Starting with the advent of the MISO ASM market on January 6, 2009, Detroit Edison buys certain ancillary services from the MISO market to serve its bundled load and at times also sells these ancillary services to the MISO ancillary services market; with both the buying and selling decisions to be based on market economics. MISO, through its unit dispatch models, determines the units that can serve the overall needs of load in the least cost manner. The specific ancillary services included in the MISO ASM wholesale market are those that were previously covered under Schedule 3 (Regulation and Frequency Response); Schedule 5 (Operating Reserve – Spinning Reserve) and Schedule 6 (Operating Reserve – Supplemental Reserve).

Line
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I am estimating the revenues and expenses associated with these costs by looking at the various MISO charge types related to these ancillary services as shown under the “Ancillary Service Market Charges” heading shown on Exhibit A-7, using the historical values from the last 12 months (September 1, 2009 to August 31, 2010). I have also included in this charge type category a couple of miscellaneous charge types (RT Miscellaneous Amount and RT Net Inadvertent Distribution Amount) associated with MISO operations that have not been captured elsewhere in my charge type cost projections.

As can be seen on line 69 of Exhibit A-7, I am projecting a net cost for 2011 of $3.3 million. This value is also carried over to line 44 of Exhibit A-5

Q. What is the Total Energy & ASM Market Costs value shown on Exhibit A-5, line 47?

A. This is the sum of the costs associated with Detroit Edison participating in the MISO Energy and ASM Markets. During 2011 the cost to Detroit Edison is estimated to be approximately $7.4 million. This is the cost that Detroit Edison incurs as a participant in the regional energy and ancillary services markets.

Q. What is the Total Base Transmission and MISO Market Costs shown on Exhibit A-5, line 50?

This is the total cost associated with procuring transmission services from MISO/ITC and participating in the MISO Energy and ASM markets. As

Line No.

shown on line 50, the total cost is estimated to be approximately $272.2 million for 2011.

Q. What items on Exhibit A-6 are being addressed by other Detroit Edison witnesses in this proceeding?

A. The DA Asset Energy Amount and the RT Asset Energy Amount represent the net of the generation revenues received for Detroit Edison generation and the load payments made to serve Detroit Edison's load. These items are included on the MISO statement, and are accounted for in Witness Wojtowicz's testimony and exhibits.

Q. Which charge type items on Exhibit A-6 have been addressed elsewhere in your testimony?

A. I have previously provided an estimate of the 2011 costs for MISO Schedules 16 and 17. The DA Market Administration Amount and the RT Market Administration Amount are the charge types associated with MISO Schedule 17. Likewise, the FTR Market Administration Amount is the charge type discussed for MISO Schedule 16. The DA and RT Schedule 24 Allocation Amounts are the charge types associated with MISO Schedule 24.

Q. What are the charge types on Exhibit A-6, involving Virtual Energy?

A. The DA Virtual Energy Amount and the RT Virtual Energy Amount primarily represent the costs and credits associated with pumping at the Ludington generation facility that is jointly owned by Detroit Edison and Consumers

Energy. The MISO model does not allow the Company to directly bid in the "load" associated with Ludington pumping, therefore it is necessary to submit Virtual bids to represent Ludington load in the MISO market. These two items can essentially be netted to determine the "net" effect of the Virtual bids, which is essentially the difference in the Day-Ahead and Real-Time LMPs at the Ludington generator nodes. The Company's experience with the MISO market to date has been that there are times when the Day-Ahead hourly LMPs are higher than those of the Real-Time LMPs, and other times when the opposite is true. Given this variability and the netting effects of these amounts, the Company cannot project a meaningful 2011 value for these charge types.

Q. Could there be additional MISO related costs that may arise over the next few months or years?

A. Yes. Currently there are still a number of changes being contemplated to MISO Energy and ASM Market Rules. The MISO Tariff is still evolving and, as a result, there may be additional cost impacts to Detroit Edison in 2011 and beyond that the Company is unaware of at this time. It is difficult to estimate all the costs that the Company will be facing until all the rules are finalized and participants gain experience with any new rules that may be put in place with the MISO Energy and ASM Markets.

When these additional MISO and/or ITC-related charges do occur, they should be approved for recovery in this case and future PSCR proceedings, as they are largely beyond Detroit Edison's control and will continue to be non-bypassable federally mandated charges incurred by the Company in order to participate in the MISO wholesale energy and ancillary services markets and to provide retail electric service to Detroit Edison's full service customers.

Q. What is your opinion concerning the MISO Energy and ASM Market costs and Transmission expenses that you are supporting in this proceeding?

A. All of the expense items listed on Exhibit A-5, Exhibit A-6, and Exhibit A-7 are necessary and integral to Detroit Edison being able to provide retail electric service to its full service customers. The rates upon which the expenses are determined are subject to approval by FERC and comply with FERC's vision for the operation and expansion of the interconnected electric transmission grid.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
THE DETROIT EDISON COMPANY	)	
for Authority to Implement a Power	)	Case No. U-16434
Supply Cost Recovery Plan in its	)	
Rate Schedules for 2011 Metered	)	
Jurisdictional Sales of Electricity	)	

EXHIBITS

OF

MICHAEL W. SHIELDS

Michigan Public Service Commision
The Detroit Edison Company
MISO Transmission, Energy, and ASM Expense
Projections for Years 2011 - 2015

Case No.: U-16434
Exhibit No.: A-5
Witness: M.W. Shields

Line		2011	2012	2013	2014	2015
1	**BASE TRANSMISSION COSTS**					
2	MISO Network Transmission					
3	Schedule 1 x $1000	$5,006	$5,083	$5,152	$5,216	$5,255
4	Schedule 9 x $1000 (ITC Zone)	$226,624	$240,929	$237,937	$235,423	$216,663
5						
6	MISO Schedule 2 Net Cost					
7	x $1000	$2,235	$2,605	$2,570	$2,532	$2,477
8						
9	MISO Schedule 10					
10	x $1000	$7,006	$7,370	$6,818	$7,074	$6,989
11						
12	MISO Schedule 10 - FERC Transmission					
13	x $1000	$4,032	$4,014	$3,994	$3,951	$3,898
14						
15	Schedules 26 - Network Upgrade Charges					
16	x $1000	$ 19,877	$ 20,434	$ 22,347	$ 23,731	$ 36,145
17						
18	**Total Base Transmission**					
19	x $1000	**$264,779**	**$280,436**	**$278,819**	**$277,928**	**$271,429**
20						
21	**MISO ENERGY and ANCILLARY SERVICES MARKET COSTS**					
22	MISO Schedule 16					
23	x $1000	$1,400	$1,145	$1,056	$1,043	$1,027
24						
25	MISO Schedule 17					
26	x $1000	$8,985	$8,057	$7,593	$7,561	$7,484
27						
28	Schedule 24 - Balancing Authority Charges					
29	x $1000	$1,130	$1,082	$1,080	$1,076	$1,065
30						
31	Net Rev. Sufficiency Guar. & Make Whole payments					
32	x $1000	($12,330)	($12,330)	($12,330)	($12,330)	($12,330)
33						
34	Net Congestion Cost					
35	x $1000	($6,273)	($6,161)	($6,205)	($6,115)	($6,240)
36						
37	Net Losses Cost					
38	x $1000	$4,686	$4,325	$3,752	$3,303	$2,160
39						
40	RT Revenue Neutrality Uplift Amount					
41	x $1000	$6,549	$6,549	$6,549	$6,549	$6,549
42						
43	ASM & Misc. Costs					
44	x $1000	$ 3,276	$ 3,276	$ 3,276	$ 3,276	$ 3,276
45						
46	**Total Energy & ASM Market Costs**					
47	x $1000	**$7,422**	**$5,943**	**$4,771**	**$4,361**	**$2,990**
48						
49	**Total Base Transmission & MISO Mkt Costs**					
50	x $1000	**$272,201**	**$286,379**	**$283,590**	**$282,289**	**$274,419**

Line No.	Charge Type
1	DA Asset Energy Amount
2	DA Congestion Rebate on Carve-out GFA
3	DA Congestion Rebate on Option B GFA
4	DA Financial Bilateral Transaction Congestion Amount
5	DA Financial Bilateral Transaction Loss Amount
6	DA Loss Rebate on Carve-out GFA
7	DA Loss Rebate on Option B GFA
8	DA Market Administration Amount
9	DA Non-Asset Energy Amount
10	DA Regulation Amount
11	DA Revenue Sufficiency Guarantee Distribution Amount
12	DA Revenue Sufficiency Guarantee Make Whole Payment Amount
13	DA Schedule 24 Allocation Amount
14	DA Spinning Reserve Amount
15	DA Supplemental Reserve Amount
16	DA Virtual Energy Amount
17	FTR Annual Transaction Amount
18	FTR ARR Revenue Amount
19	FTR ARR Stage 2 Distribution
20	FTR Full Funding Guarantee Amount
21	FTR Guarantee Uplift Amount
22	FTR Hourly Allocation Amount
23	FTR Infeasible ARR Uplift Amount
24	FTR Market Administration Amount
25	FTR Monthly Allocation Amount
26	FTR Monthly Transaction Amount
27	FTR Yearly Allocation Amount
28	RT Asset Energy Amount
29	RT Congestion Rebate on Carve-out GFA
30	RT Contingency Reserve Deployment Failure Charge Amount
31	RT Distribution of Losses Amount
32	RT Excessive\Deficient Energy Deployment Charge Amount
33	RT Excessive Energy Amount
34	RT Financial Bilateral Transaction Congestion Amount
35	RT Financial Bilateral Transaction Loss Amount
36	RT Loss Rebate on Carve-out GFA
37	RT Market Administration Amount
38	RT Miscellaneous Amount
39	RT Net Inadvertent Distribution Amount
40	RT Net Regulation Adjustment Amount
41	RT Non-Asset Energy Amount
42	RT Non-Excessive Energy Amount
43	RT Price Volatility Make Whole Payment
44	RT Regulation Amount
45	RT Regulation Cost Distribution Amount
46	RT Revenue Neutrality Uplift Amount
47	RT Revenue Sufficiency Guarantee First Pass Dist Amount
48	RT Revenue Sufficiency Guarantee Make Whole Payment Amount
49	RT Schedule 24 Allocation Amount
50	RT Schedule 24 Distribution Amount
51	RT Spinning Reserve Amount
52	RT Spinning Reserve Cost Distribution Amount
53	RT Supplemental Reserve Amount
54	RT Supplemental Reserve Cost Distribution Amount
55	RT Virtual Energy Amount

Michigan Public Service Commision
The Detroit Edison Company
MISO Settlement Statement Charges/Credits
Projections for Years 2011 - 2015

Case No. U-16047
Exhibit No.: A-7
Witness: M.W. Shields

Line No.			2011	2012	2013	2014	2015
1			**2011**	**2012**	**2013**	**2014**	**2015**
2			($ x1000)	($ x1000)	($ x1000)	($ x1000)	($ x1000)
3	**Revenue Sufficency Guarantee and Make Whole Payments Calculation**						
4							
5	DA Revenue Sufficiency Guarantee Distribution Amount	Sep 09 - Aug 10	1,877	1,877	1,877	1,877	1,877
6	DA Revenue Sufficiency Guarantee Make Whole Payment Amount	Sep 09 - Aug 10	(530)	(530)	(530)	(530)	(530)
7	RT Revenue Sufficiency Guarantee First Pass Dist Amount	Sep 09 - Aug 10	5,607	5,607	5,607	5,607	5,607
8	RT Revenue Sufficiency Guarantee Make Whole Payment Amount	Sep 09 - Aug 10	(14,782)	(14,782)	(14,782)	(14,782)	(14,782)
9	RT Price Volatility Make Whole Payment	Sep 09 - Aug 10	(4,502)	(4,502)	(4,502)	(4,502)	(4,502)
10			=========	=========	=========	=========	=========
11		**Total**	**$ (12,330)**	**$ (12,330)**	**$ (12,330)**	**$ (12,330)**	**$ (12,330)**
12							
13	**Congestion Calculation**						
14							
15	Congestion Amount between Generation and Load		3,481	3,593	3,549	3,639	3,515
16	DA Financial Bilateral Transaction Congestion Amount	Sep 09 - Aug 10	3,807	3,807	3,807	3,807	3,807
17	RT Financial Bilateral Transaction Congestion Amount	Sep 09 - Aug 10	221	221	221	221	221
18	DA Congestion Rebate on Carve-out GFA	Sep 09 - Aug 10	(3,807)	(3,807)	(3,807)	(3,807)	(3,807)
19	RT Congestion Rebate on Carve-out GFA	Sep 09 - Aug 10	(221)	(221)	(221)	(221)	(221)
20	FTR Hourly Allocation Amount	Sep 09 - Aug 10	(4,574)	(4,574)	(4,574)	(4,574)	(4,574)
21	FTR Monthly Allocation Amount	Sep 09 - Aug 10	(439)	(439)	(439)	(439)	(439)
22	FTR Yearly Allocation Amount	Sep 09 - Aug 10	(30)	(30)	(30)	(30)	(30)
23	FTR ARR Stage 2 Distribution	Sep 09 - Aug 10	(5,830)	(5,830)	(5,830)	(5,830)	(5,830)
24	FTR Monthly Transaction Amount	Sep 09 - Aug 10	-	-	-	-	-
25	FTR Annual Transaction Amount	Sep 09 - Aug 10	6,134	6,134	6,134	6,134	6,134
26	FTR ARR Revenue Amount	Sep 09 - Aug 10	(6,501)	(6,501)	(6,501)	(6,501)	(6,501)
27	FTR Full Funding Guarantee Amount	Sep 09 - Aug 10	(593)	(593)	(593)	(593)	(593)
28	FTR Guarantee Uplift Amount	Sep 09 - Aug 10	680	680	680	680	680
29	FTR Infeasible ARR Uplift Amount	Sep 09 - Aug 10	1,399	1,399	1,399	1,399	1,399
30			=========	=========	=========	=========	=========
31			**$ (6,273)**	**$ (6,161)**	**$ (6,205)**	**$ (6,115)**	**$ (6,240)**
32							
33	**Losses Calculation**						
34							
35	Marginal Losses Amount between Generation and Load		46,746	46,653	46,123	46,324	45,602
36	DA Financial Bilateral Transaction Loss Amount	Sep 09 - Aug 10	6,657	6,657	6,657	6,657	6,657
37	RT Financial Bilateral Transaction Loss Amount	Sep 09 - Aug 10	537	537	537	537	537
38	DA Loss Rebate on Carve-out GFA	Sep 09 - Aug 10	(6,657)	(6,657)	(6,657)	(6,657)	(6,657)
39	RT Loss Rebate on Carve-out GFA	Sep 09 - Aug 10	(537)	(537)	(537)	(537)	(537)
40	RT Distribution of Losses Amount	Sep 09 - Aug 10	(18,513)	(18,513)	(18,513)	(18,513)	(18,513)
41			=========	=========	=========	=========	=========
42		Subtotal	$ 28,233	$ 28,140	$ 27,610	$ 27,811	$ 27,089
43							
44	Revenue for Transmission Losses		$ (23,548)	$ (23,815)	$ (23,858)	$ (24,508)	$ (24,929)
45							
46		**Total**	**$ 4,686**	**$ 4,325**	**$ 3,752**	**$ 3,303**	**$ 2,160**
47							
48							
49	**RT Revenue Neutrality Uplift Amount**	Sep 09 - Aug 10	**$ 6,549**	**$ 6,549**	**$ 6,549**	**$ 6,549**	**$ 6,549**
50							
51	**Ancillary Service Market & Misc. Charges**						
52							
53	DA Regulation Amount	Sep 09 - Aug 10	$ (2,088)	$ (2,088)	$ (2,088)	$ (2,088)	$ (2,088)
54	DA Spinning Reserve Amount	Sep 09 - Aug 10	$ (1,903)	$ (1,903)	$ (1,903)	$ (1,903)	$ (1,903)
55	DA Supplemental Reserve Amount	Sep 09 - Aug 10	$ (141)	$ (141)	$ (141)	$ (141)	$ (141)
56	RT Excessive\Deficient Energy Deployment Charge Amount	Sep 09 - Aug 10	$ 92	$ 92	$ 92	$ 92	$ 92
57	RT Excessive Energy Amount	Sep 09 - Aug 10	$ (281)	$ (281)	$ (281)	$ (281)	$ (281)
58	RT Net Regulation Adjustment Amount	Sep 09 - Aug 10	$ 52	$ 52	$ 52	$ 52	$ 52
59	RT Regulation Amount	Sep 09 - Aug 10	$ 178	$ 178	$ 178	$ 178	$ 178
60	RT Regulation Cost Distribution Amount	Sep 09 - Aug 10	$ 2,238	$ 2,238	$ 2,238	$ 2,238	$ 2,238
61	RT Spinning Reserve Amount	Sep 09 - Aug 10	$ 392	$ 392	$ 392	$ 392	$ 392
62	RT Spinning Reserve Cost Distribution Amount	Sep 09 - Aug 10	$ 2,917	$ 2,917	$ 2,917	$ 2,917	$ 2,917
63	RT Supplemental Reserve Amount	Sep 09 - Aug 10	$ (186)	$ (186)	$ (186)	$ (186)	$ (186)
64	RT Supplemental Reserve Cost Distribution Amount	Sep 09 - Aug 10	$ 947	$ 947	$ 947	$ 947	$ 947
65	RT Contingency Reserve Deployment Failure Charge Amount	Sep 09 - Aug 10	$ 81	$ 81	$ 81	$ 81	$ 81
66	RT Miscellaneous Amount	Sep 09 - Aug 10	$ 334	$ 334	$ 334	$ 334	$ 334
67	RT Net Inadvertent Distribution Amount	Sep 09 - Aug 10	$ 645	$ 645	$ 645	$ 645	$ 645
68							
69		**Total**	**$ 3,276**	**$ 3,276**	**$ 3,276**	**$ 3,276**	**$ 3,276**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
THE DETROIT EDISON COMPANY	)	
for Authority to Implement a Power	)	Case No. U-16434
Supply Cost Recovery Plan in its	)	
Rate Schedules for 2011 Metered	)	
Jurisdictional Sales of Electricity	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SHERRIE L. SIEFMAN

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF SHERRIE L. SIEFMAN

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Q. What is your name, business address and who are you testifying on behalf of?

A. My name is Sherrie L. Siefman. My business address is: One Energy Plaza, Detroit, Michigan 48226. I am testifying on behalf of The Detroit Edison Company (Detroit Edison, Edison or Company).

Q. What is your present position with the Company?

A. I am the Supervisor of Long Term Energy Forecasting.

Q. Please state your educational background.

A. I received a Bachelor of Science degree in Financial Administration from Michigan State University. I received a Master of Business Administration degree with a concentration in Accounting from Wayne State University. I have also completed several Company sponsored courses and attended various seminars to further my professional development.

Q. Please describe your professional experience.

A. I joined the Company in January 1982 as an Associate Business Analyst in Power Generation Administration assigned to Bulk Power Transactions. I was responsible for preparing monthly billings and various reports on power transactions with interconnected systems.

In January 1983, I transferred to the Revenue Requirement Department where I held positions of increasing responsibility. I prepared workpapers and exhibits supporting the cost of service study, working capital and

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historical revenue deficiency. I coordinated and managed various cases before the MPSC. I analyzed monthly PSCR and Steam Cost Recovery (SCR) revenues and costs and prepared the monthly PSCR report for filing with the MPSC. I performed depreciation studies. I analyzed fixed charge rates and investment for cost sharing with Consumers Energy for the Michigan Electric Power Coordination Center (MEPCC). I was the back-up to the rate witness in the 1986 PSCR and SCR reconciliation cases and in the 1988 PSCR, 1988 SCR and 1993 PSCR Plan cases. I was also a back-up witness in the Michigan Residential Conservation Service reconciliation, Case No. U-6633-R, and in several Expense Stabilization Procedure cases.

In February 1996, I transferred to Power Generation - Mergers and Acquisitions as a Research Specialist in the Business Intelligence group. In this capacity, I performed benchmark studies of utilities and tracked utility mergers & acquisitions, sales of generating assets and new power generation projects.

In March 2000, I was promoted to Principal Market Analyst in the M&A Projects group of Power Generation - Mergers and Acquisitions. I continued to track new power generation projects and changes in capacity at existing facilities and prepared letters of interest for the Company to participate in generation asset sales.

In November 2000, through a re-organization, I was transferred to Market Intelligence. I was responsible for maintaining the MAIN region in the

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PROMOD model.

In July 2001, I transferred to Corporate Energy Forecasting. In March 2002, I was appointed Supervisor of Long Term Energy Forecasting.

Q. What are your duties as Supervisor of Long Term Energy Forecasting?

A. I am responsible for the development of electric sales forecasts on a monthly, annual and multi-year basis. These activities include data collection, statistical analysis of data, forecast model building and interaction with other Company departments on forecast-related activities. It also includes preparation and presentation of forecast and variance reports.

Q. Do you belong to any professional organizations?

A. I am a member and secretary of the Electric Utility Forecasters Forum (EUFF). EUFF discusses forecast methodologies, data sources and issues common to many electric utilities. I am a member of Edison Electric Institute's (EEI's) Load Forecasting Group (LFG). The LFG's purpose is to enhance load forecasting capabilities by exchanging information among the group's base of experienced and knowledgeable load forecasters. I am also a member of the Detroit Association for Business Economics (DABE). DABE discusses economic issues affecting Southeastern Michigan.

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Q. Have you previously sponsored testimony before the Michigan Public Service Commission?

A. Yes. I sponsored testimony in the following cases:

U-15002	2007 PSCR Plan Case
U-15417	2008 PSCR Plan Case
U-15677	2009 PSCR Plan Case
U-15768	Detroit Edison’s general electric rate case
U-15806	Detroit Edison’s Energy Optimization and Renewable (RPS & EO) Portfolio Standard cases
U-16047	2010 PSCR Plan Case
U-15806-EO	Detroit Edison’s Amended Energy Optimization case

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Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide Detroit Edison's current electric sales and system output forecast for the period 2010-2015 and to explain the basis for this forecast.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit	Description
A-8	Summary of service area annual electric sales, output, and demand
A-9	Monthly distribution of service area electric sales and output
A-10	Summary of Detroit Edison annual electric sales, output, and demand
A-11	Summary of Electric Choice annual sales
A-12	Summary of economic outlook

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. Can you describe Exhibit A-8?

A. Exhibit A-8 shows service area annual electric sales for the four major rate classifications: Residential, Commercial, Industrial, and Other. Total sales, net system output (NSO), and annual peak demand are also shown. The years 2004 through 2009 are historical; 2010 is a combination of seven

Line No.

months historical and five months forecast; and 2011 through 2015 are forecast. All historical sales, NSO and annual peak demands are actual (not temperature-normalized). Sales and NSO for the first seven months of 2010 are actual. 2010 peak demand is actual (not temperature-normalized) and preliminary. All forecasted values assume normal temperatures.

Q. Can you describe Exhibit A-9?

A. Exhibit A-9 shows monthly service area electric sales and NSO for each year of the forecast. 2010 is a combination of seven months historical and five months forecast. The monthly sales and NSO are consistent with the annual projections given in Exhibit A-8.

Q. Is the service area forecast based upon Detroit Edison's current official load forecast?

A. Yes, it is.

Q. Can you describe Exhibit A-10?

A. Exhibit A-10 shows Detroit Edison annual electric sales for the four major rate classifications, total sales, NSO and peak demand. Detroit Edison sales are calculated as service area sales less Electric Choice sales. The years 2004 through 2009 are historical; 2010 is a combination of historical and forecast, as described above; and 2011 through 2015 are forecast. All historical sales, NSO and annual peak demands are actual (not temperature-normalized). Sales and NSO for the first seven months of 2010 are actual. 2010 peak demand is actual (not temperature-normalized)

Line No.

and preliminary. All forecasted values assume normal temperatures.

Q. Can you describe Exhibit A-11?

A. Exhibit A-11 shows Electric Choice annual sales for the four major rate classifications. 2004 through 2009 are historical; 2010 is a combination of historical and forecast, as described above; and 2011 through 2015 are forecast. All historical sales are actual (not temperature-normalized). Sales for the first seven months of 2010 are actual. All forecasted values assume normal temperatures.

Q. Can you describe Exhibit A-12?

A. Exhibit A-12 shows the major economic parameters used in the forecast models. The years 2004 through 2009 are historical. The years 2010 through 2015 are forecast.

Q. What is the compound annual growth rate of service area electric sales over the forecast period?

A. Service area electric sales are forecast to decrease from temperature-normalized sales of 48,280 GWh in 2009 to temperature-normalized sales of 46,874 GWh in 2015. This represents a 0.5% average annual decrease in sales. Any growth in service area sales due to positive economics is more than offset by 2012 by the sales reductions due to the Company's Commission-approved 2008 PA 295 Energy Optimization program.

Sales are expected to decrease on an average annual basis in the

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Residential Class by 2.3% and in the Commercial Class by 1.1%. Industrial Class sales are expected to increase by 5.7% on an average annual basis. This growth rate is positive and historically high only because in the base year 2009, Industrial Class sales due to auto sector restructuring were extremely low. Industrial Class sales in 2011 of 12,570 GWh is below sales in 2008 of 13,349 GWh and well below sales in 2000 of 16,199 GWh. Other Class sales are expected to decrease by 16.4% on an average annual basis from 2009 to 2015. The reason for the decline is the expiration of contracts with three Wholesale customers (Croswell, Sebewaing and Wolverine).

Q. Can you explain the general approach used in developing the forecast of service area electric sales and system output?

A. For most sectors of the forecast, electric sales levels are related to the various economic, technological, regulatory, and demographic factors that have affected them in the past. The procedure begins with the assembly of historical data relating to the various sectors of the forecast. These data are examined and the factors that are statistically significant in explaining electric sales are identified using regression techniques. The forecast is developed employing the appropriate regression equations.

Economic driving variables (explanatory factors), such as car and truck production, steel production, employment, and others, are entered into the regression equations to calculate projected future electric sales levels.

The forecast is developed separately for each of four main categories:

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manufacturing, non-manufacturing, Residential Class, and Other Class. Sales in the manufacturing sector are forecast by developing subcategory equations for the automotive industry, the steel industry, chemicals, petroleum, metal fabrication, manufacturing equipment, rubber and plastics, non-metal processing, mining and other manufacturing. Modifications are made, as required, for displacement by customer self-generation in the manufacturing sectors. The non-manufacturing category is forecast using regression equations for nine subcategories. The subcategories are then disaggregated into markets. The non-manufacturing sales for each market are divided into Primary Class and Commercial Class components.

In the Residential Class, an end-use approach is employed in which 38 different appliances or appliance groups are defined. The individual appliance forecasts that result are then aggregated to constitute the total Residential Class sales forecast. The Other Class is forecast by separating the class into wholesale-for-resale, municipal water pumping, and street lighting. System output is forecast as the sum of the electric sales values and the projected losses.

Q. Could you provide an example of how the forecast analysis was developed for one or more of the sales categories?

A. Yes, I will describe the approaches taken with the automotive sector, which is the largest manufacturing subcategory, and the Residential Class.

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Q. How was the automotive forecast developed?

A. For the development of the automotive forecast, the sector was disaggregated into seven groups of automotive facilities, i.e., assembly plants, stamping plants, powertrain/drivetrain plants, research and administrative facilities (auto tech), other parts plants and parts suppliers, foundries, and other automotive plants. Electricity sales for the groups identified above were forecast using regression-based models with automotive production as the primary explanatory variable. Additional effects from announced plant closings or expansions, plant specific information and displacement generation were also factored into these models.

Q. How was the Residential Class forecast developed?

A. Energy sales in the Residential Class were forecast by an end-use method including 38 different appliances or appliance groups. For each forecast year, three separate items were forecast: (1) number of residential customers, (2) saturations of major appliances, and (3) average energy use per appliance. For each appliance, the product of these three forecast values yields the annual energy sales. The total for all appliances is the total annual Residential Class energy sales. This end-use approach incorporates projected increases in energy efficiency of the various appliances into the total Residential Class electric sales.

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Q. Once you have all the equations developed, how do you forecast electric sales?

A. Once the electric sales forecast equations are established, it is then necessary to investigate and adopt appropriate forecasts of the explanatory variables included in those equations. The economic and demographic variables incorporated in these equations are forecast by the Corporate Economist of Detroit Edison.

Q. What is the condition of the national economy just prior to the forecast period?

A. The economy continued to recover in the first half of 2010, but the rate of that recovery slowed in the second quarter.

Real gross domestic product (GDP), the comprehensive measure of goods and services produced in the United States, rose at a seasonally adjusted annualized rate of 2.4% in the second quarter of 2010 after rising at a rate of 3.7% in the first quarter. The greatest contribution to second-quarter growth came from gross private domestic investment, but a stronger dollar fostered higher imports, which proved to be a significant drag on the quarter's growth.

After increasing at a rate of 1.9% in the first quarter, personal consumption expenditures rose 1.6% in the second quarter. Government consumption expenditures and gross investment rose 4.4% in the second quarter following an outright decline of 1.6% in the first quarter.

Line No.

Motor vehicle production declined at a rate of 0.5% in the second quarter after rising in the first quarter. Through the first half of the year, light vehicle unit sales varied from a seasonally adjusted annualized low of 10.5 million in February to a high of 11.7 million in March. Sales in the first six months of the year average out to a seasonally adjusted annualized rate of 11.2 million units. To put this in perspective, light vehicle sales reached a high of 17.4 million in 2000.

The housing market is emerging from its crisis slowly and with occasional reversals. Housing starts were at a seasonally adjusted annualized rate of 0.617 million in the first quarter and 0.602 million in the second quarter. These compare to 0.530 million and 0.537 million in the first and second quarters, respectively, of 2009. Housing starts reached 2.1 million annually as recently as 2005.

The dollar's exchange rate with the currencies of major trading partners rose at an annualized rate of 15.6% in the second quarter after rising at a rate of 11.3% in the first quarter. Greece's financial crisis contributed to the dollar's rise. The stronger dollar makes imports more attractive to American consumers and American exports less attractive to foreign buyers.

The seasonally adjusted Consumer Price Index for All Urban Consumers declined in all three months of the second quarter. June's index stood only 1.1% above its level of 12 months earlier. The personal consumption expenditures implicit price deflator rose at an annualized rate of 0.1% in the

Line No.

second quarter after rising at a rate of 2.1% in the first quarter. The Federal Reserve Bank's Open Market Committee watches this deflator most closely of the various published inflation measures when setting monetary policy.

Q. What is the outlook for the national economy in 2011?

A. Real gross domestic product is forecast to increase by only 2.7% in 2011 after rising by 3.1% in 2010. Correspondingly, disposable personal income is expected to rise by 1.8% in 2011 following a 1.9% increase in 2010. Personal consumption expenditures are expected to grow by 2.8% in 2011 after rising by 2.4% in 2010.

The federal budget deficit appears headed to reach $1.2 trillion in 2011 after hitting $1.4 trillion in 2009 and $1.3 trillion in 2010.

Total light vehicle production in the United States is forecast to reach 8.4 million in 2011 after hitting 7.5 million in 2010. This corresponds to 13.2 million units of sales in 2011 and 11.5 million in 2010. As a basis of comparison, light vehicle production reached 12.6 million in 1999.

The forecast calls for industrial production to rise by 5.8% in 2010 and 4.5% in 2011. Despite consecutive yearly gains, the forecast 2011 index will be slightly below its 2006 level.

The housing market will take several years or even longer to achieve its pre-recession vitality. Only the most gradual improvements are expected in

Line No.

the intervening period. For example, housing starts are forecast to increase to 0.962 million in 2011 after reaching 0.638 million in 2010. These numbers are woefully lower than 2005's 2.1 million.

Overall, the economy will continue its laborious comeback in 2011. At the heart of the problem are the massive debt and loss of personal savings which continue to weigh on many consumers' decisions. The situation is serious enough that many analysts expect the economy to turn down again sometime in 2011. Even if the feared double-dip recession fails to strike, growth will almost certainly be sluggish and tenuous for several years.

Q. What is the outlook for Southeast Michigan's economy in 2011?

A. Government loans to Chrysler and General Motors have saved Michigan from economic disaster in 2011, but local auto production most likely will never attain its previous volume. The local auto industry, along with the state's entire economy, has undergone a structural change.

Overall employment is forecast to increase by 2.0% in 2011. This follows an expected decrease of 2.4% in 2010. Without the government loans, both Chrysler and General Motors could easily have faced liquidation and pitched employment into a freefall. However, employment does not return to its 2007 level in the forecast period.

Mining, logging, and construction employment is expected to rise 0.5% in 2011 after decreasing 2.8% in 2010. Construction is the largest component

Line No.

of this category, and it will remain constrained by the housing market's travails.

Total private nonmanufacturing employment is forecast to rise by 1.9% in 2011 after falling by 2.2% in 2010. As usual, the local economy will ride the fortunes of the auto industry. The industry is only eking out small gains, so employment follows accordingly.

Governments suffer from reduced revenue, and their employment levels reflect this. All categories of government employment are forecast to decline by 2.1% in 2011 following a 3.4% decline in 2010.

Manufacturing employment is forecast to rise by 9.1% in 2011 after declining by 2.2% in 2010. However, much of that increase is illusory, since it comes from the expected re-opening of General Motors' Orion Township Assembly Plant. The plant has been shut down since 2009 to retool for production of a small, fuel-efficient car. It should be noted that the reconfigured Orion plant will employ fewer workers than before it closed for retooling.

The outlook for local auto production anticipates output of 1.0 million vehicles in 2010 and 1.2 million in 2011, which is well below the 2.6 million attained as recently as 2000.

Raw steel production is forecast to reach 5.2 million tons in 2010 and 5.7 million in 2011. This is well short of the recent high of 6.9 million tons reached in 2000 and a mere shadow of the over 10 million tons produced in the 1970s.

The number of housing permits issued within the area is forecast to rise by 619 in 2010 and decline by 34 in 2011. It is worth noting that the expectation for 2.3 thousand permits in 2011 pales in comparison to 22.5 thousand permits issued in 2000.

Population is forecast to decline by 0.4% in both 2010 and 2011. A decline in 2011 would mark the seventh consecutive year that population has fallen. Jobs are increasing, but not fast enough to retain, let alone attract, citizens.

Q. What is the outlook for Electric Choice sales for 2010?

A. Based on sales reported through July 2010 and an extrapolation of the trend for the year, Electric Choice sales should reach 5,027 GWh for the year. On a temperature-normalized basis, Electric Choice sales for 2010 should be 4,987 GWh.

Q. What is the forecast for Electric Choice sales for 2011 through 2015?

A. The forecast for Electric Choice sales by rate classification is shown on Exhibit A-11.

Line No.

Q. How was the Electric Choice sales forecast developed?

A. The Electric Choice sales forecast was held constant at the temperature-normalized sales level expected for 2010 of 4,987 GWh. Market clearing prices are not expected to increase significantly from current levels through 2012, therefore, no change in Electric Choice sales is forecasted. Since a longer-term electricity market is not liquid and possesses a large degree of uncertainty, the Electric Choice sales forecast was held constant beyond 2012.

Q. What assumptions were made in the development of the forecast sales reductions for the Company's Commission-approved 2008 PA 295 Energy Optimization program?

A. The forecast sales reductions for the Company's Commission-approved 2008 PA 295 Energy Optimization program are based upon the Company's amended Energy Optimization plan approved by the Commission on June 3, 2010. The energy savings in the amended Energy Optimization plan are based on annual savings for the measures and not dependent on when during the year the measures were implemented. I have assumed that the measures are implemented uniformly throughout the year. Therefore, the sales reductions for the first year of a measure are half of the energy savings in the amended Energy Optimization plan. The full impact of a measure is realized in the second year and thereafter.

Based on the program offerings, the service area reductions were allocated to the major classes of customers. Since the amended Energy Optimization

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plan is being offered to all customers in Detroit Edison's service area regardless of their generation provider, the service area sales reductions were prorated to both Detroit Edison customers and Electric Choice customers. Reductions for Electric Choice sales were based on the ratio of Electric Choice sales to service area sales.

Q. What were the actual and projected 2009 Detroit Edison annual sales?

A. Detroit Edison's 2009 annual sales were 45,977 GWh. Forecast sales for 2009 were 47,883 GWh. The total variance of 1,906 GWh is disaggregated as follows:

Cooler than normal summer	-816 GWh
Higher Electric Choice sales than predicted	-180 GWh
Poor economy	- 910 GWh
Total	-1,906 GWh

Q. What method did you employ to calculate monthly distributions of annual values of electric sales and system output?

A. For each of the sales categories, monthly distributions were calculated using the Hourly Electric Load Model (HELM). The HELM model produced calendar-based outputs based on historical distributions for the various customer sales categories.

Q. Can you explain HELM?

A. HELM was developed by EPRI and aggregates hourly demand profiles from various sales categories or end-uses into a system annual loadshape. The

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annual sales and hourly demand profiles for each sales category or end-use are key inputs to this model.

Q. How was the peak system demand forecast made?

A. HELM was used to forecast annual peak demand. HELM was also utilized to determine monthly peak demands in the forecast period.

Q. What temperature assumptions were made regarding the peak demand forecast?

A. Normal average temperature on the day of the annual peak is assumed to be 83°F, using an average of 1971 through 2000 mean daily temperatures for Detroit Metropolitan Airport. The peak day is assumed to occur on a weekday in July or August.

Q. What temperature assumptions were made regarding the electric sales forecast?

A. Normal temperature conditions were utilized for the projections of weather-sensitive sales. Normal average temperatures for a calendar year are based on the average of 1971 through 2000 mean daily temperatures for Detroit Metropolitan Airport. Normal cooling degree days and heating degree days are 736 and 6,422, respectively.

Q. Does the peak demand projection include the impact of interruptible loads and other Demand Side Management (DSM) programs?

A. No. Peak demand projections do not reflect reductions due to interruptible

Line
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loads or DSM.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
THE DETROIT EDISON COMPANY	)	
for Authority to Implement a Power	)	Case No. U-16434
Supply Cost Recovery Plan in its	)	
Rate Schedules for 2011 Metered	)	
Jurisdictional Sales of Electricity	)	

EXHIBITS

OF

SHERRIE L. SIEFMAN

Michigan Public Service Commission
The Detroit Edison Company
Summary of Service Area Annual Electric Sales, Output, and Demand
Historical: 2004-2009
Forecast: 2010-2015

Case No.: U-16434
Exhibit: A-8
Witness: Sherrie L. Siefman
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Annual Electric Sales (Million kWh)					**System Output**	**Peak Demand**
Line No.	**Year**	**Residential**	**Commercial**	**Industrial**	**Other**	**Total**	**(Million kWh)**	**(MW)**
1	2004	15,083	20,452	14,088	2,598	52,222	55,656	11,357
2	2005	16,813	20,812	13,885	2,720	54,229	58,117	12,341
3	2006	15,769	20,497	14,033	3,228	53,528	57,348	12,901
4	2007	16,147	20,914	13,993	3,301	54,355	58,128	12,229
5	2008	15,493	20,114	13,349	3,217	52,174	55,703	11,251
6	2009	14,625	19,750	9,849	3,229	47,453	50,852	10,627
7								
8	2010	15,475	19,577	11,766	3,307	50,126	53,720	11,605
9	2011	14,621	19,119	12,570	3,207	49,517	52,880	11,477
10	2012	14,239	19,011	13,162	1,101	47,513	50,854	11,174
11	2013	13,854	18,906	13,606	1,096	47,462	50,775	11,085
12	2014	13,517	18,856	13,831	1,094	47,297	50,582	10,991
13	2015	13,258	18,713	13,801	1,102	46,874	50,122	10,851

Michigan Public Service Commission
The Detroit Edison Company
Monthly Distribution of Service Area Electric Sales and Output
Forecast: 2010-2015

Case No.: U-16434
Exhibit: A-9
Witness: Sherrie L. Siefman

Electric Sales (Million kWh)

Line No.	(a) Year	(b) Jan	(c) Feb	(d) Mar	(e) Apr	(f) May	(g) Jun	(h) Jul	(i) Aug	(j) Sep	(k) Oct	(l) Nov	(m) Dec
1	2010	4,239	3,804	3,945	3,653	4,042	4,581	5,210	4,699	3,980	3,947	3,831	4,195
2	2011	4,098	3,770	4,060	3,741	3,961	4,335	4,765	4,694	4,037	3,986	3,860	4,210
3	2012	3,927	3,623	3,894	3,581	3,792	4,165	4,586	4,521	3,876	3,820	3,695	4,032
4	2013	3,920	3,622	3,893	3,583	3,794	4,165	4,571	4,512	3,873	3,819	3,689	4,021
5	2014	3,903	3,610	3,880	3,573	3,784	4,151	4,550	4,494	3,861	3,809	3,677	4,005
6	2015	3,868	3,579	3,847	3,542	3,751	4,113	4,504	4,451	3,827	3,776	3,645	3,971
7													
8													
9						Net System Output (Million kWh)							
10													
11		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
12													
13	2010	4,531	4,043	4,195	3,885	4,310	4,920	5,640	5,088	4,310	4,214	4,092	4,490
14	2011	4,363	4,009	4,320	3,973	4,226	4,632	5,131	5,056	4,349	4,234	4,103	4,484
15	2012	4,190	3,861	4,152	3,812	4,055	4,460	4,949	4,881	4,187	4,067	3,936	4,304
16	2013	4,181	3,858	4,149	3,812	4,055	4,457	4,931	4,868	4,182	4,063	3,928	4,290
17	2014	4,162	3,844	4,134	3,800	4,043	4,441	4,907	4,847	4,168	4,051	3,914	4,271
18	2015	4,123	3,810	4,098	3,767	4,008	4,399	4,857	4,801	4,130	4,016	3,880	4,235

Michigan Public Service Commission
The Detroit Edison Company
Summary of Detroit Edison Annual Electric Sales, Output, and Demand
Historical: 2004-2009
Forecast: 2010-2015

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
		Annual Electric Sales (Million kWh)						**Coincident**
							System	**Peak**
Line							**Output**	**Demand ***
No.	**Year**	**Residential**	**Commercial**	**Industrial**	**Other**	**Total**	**(Million kWh)**	**(MW)**
1	2004	15,082	13,425	11,472	2,598	42,576	46,024	9,667
2	2005	16,812	15,619	12,316	2,720	47,467	50,688	11,070
3	2006	15,769	17,947	13,234	3,228	50,178	53,783	12,364
4	2007	16,147	19,330	13,340	3,301	52,117	55,600	11,869
5	2008	15,493	18,920	13,086	3,217	50,716	54,178	11,026
6	2009	14,625	18,200	9,922	3,229	45,977	49,174	10,347
7								
8	2010	15,474	16,237	10,081	3,307	45,099	48,364	10,737
9	2011	14,621	15,816	10,887	3,207	44,531	47,595	10,558
10	2012	14,239	15,708	11,478	1,101	42,526	45,568	10,255
11	2013	13,854	15,603	11,922	1,096	42,476	45,489	10,167
12	2014	13,517	15,553	12,147	1,094	42,310	45,296	10,072
13	2015	13,258	15,410	12,117	1,102	41,887	44,836	9,932

* Coincident to the Service Area Peak Demand.

Michigan Public Service Commission
The Detroit Edison Company
Summary of Electric Choice Annual Sales
Historical: 2004-2009
Forecast: 2010-2015

Case No.: U-16434
Exhibit: A-11
Witness: Sherrie L. Siefman
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)
		Annual Electric Sales (Million kWh)				
Line No.	Year	Residential	Commercial	Industrial	Other	Total
1	2004	1	7,028	2,617	0	9,646
2	2005	1	5,193	1,568	0	6,763
3	2006	1	2,550	799	0	3,350
4	2007	0	1,584	653	0	2,238
5	2008	0	1,194	263	0	1,458
6	2009	0	1,550	-73	0	1,477
7						
8	2010	1	3,341	1,685	0	5,027
9	2011	0	3,303	1,684	0	4,987
10	2012	0	3,303	1,684	0	4,987
11	2013	0	3,303	1,684	0	4,987
12	2014	0	3,303	1,684	0	4,987
13	2015	0	3,303	1,684	0	4,987

* 2009 Electric Choice Industrial sales were negative due to prior period billing adjustments.

Michigan Public Service Commission
The Detroit Edison Company
Summary of Economic Outlook
Historical: 2004-2009
Forecast: 2010-2015

Case No.: U-16434
Exhibit: A-12
Witness: Sherrie L. Siefman

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
Line No.	Year	Change In Real GDP (Percent)	Change in U.S. CPI-U (Percent)	Index of Industrial Production (2007=100)	U.S. Car & Truck Production (Millions)	Detroit Area Car & Truck Production (Millions)	Detroit Area Steel Production (MM Tons)	Detroit Area Total Employment (Thousands)	Detroit Area Res. Permits (Thousands)
1	2004	3.6	2.7	92.3	11.6	2.0	5.7	2,295.1	24.9
2	2005	3.1	3.4	95.3	11.5	2.1	5.8	2,293.2	18.1
3	2006	2.7	3.2	97.4	10.8	1.9	5.9	2,248.4	10.2
4	2007	2.1	2.8	100.0	10.5	1.8	6.1	2,207.4	5.3
5	2008	0.4	3.8	96.7	8.5	1.5	4.8	2,139.1	2.9
6	2009	-2.4	-0.4	87.7	5.6	0.9	2.6	1,969.3	1.7
7									
8	2010	3.1	1.5	92.8	7.5	1.0	5.2	1,922.5	2.3
9	2011	2.7	1.4	97.0	8.4	1.2	5.7	1,961.8	2.3
10	2012	3.0	2.0	100.0	9.0	1.4	5.7	1,986.8	2.8
11	2013	2.7	2.1	103.6	9.7	1.4	5.8	1,996.5	3.2
12	2014	3.0	2.1	107.1	10.3	1.5	6.0	2,005.6	3.2
13	2015	2.8	2.1	110.5	10.3	1.5	6.1	2,007.2	3.3

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
THE DETROIT EDISON COMPANY	)	
for Authority to Implement a Power	)	Case No. U-16434
Supply Cost Recovery Plan in its	)	
Rate Schedules for 2011 Metered	)	
Jurisdictional Sales of Electricity	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ANGELA P. WOJTOWICZ

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF ANGELA P. WOJTOWICZ

Line No.

Q. What is your name, business address and by whom are you employed?

A. My name is Angela P. Wojtowicz. My business address is 414 S. Main Street, Suite 300, Ann Arbor, Michigan 48104. I am employed by The Detroit Edison Company (Detroit Edison or the Company).

Q. What is your current position with the Company?

A. I am the Supervisor of the Midterm Optimization group in the Generation Optimization department of the Regulated Marketing Organization.

Q. What is your educational background?

A. I received a Bachelor of Science Degree in Nuclear Engineering from The University of Michigan in 1991. I later received a Master of Science Degree in Nuclear Engineering from The University of Michigan in 1992.

Q. Do you hold any certifications?

A. Yes. I am certified as a North American Electric Reliability Council (NERC) Certified System Operator for balancing and interchange.

Q. What is your work experience?

A. After obtaining my Bachelor's degree from The University of Michigan in the spring of 1991, I was employed by Advent Engineering Services. During my employment at Advent, I worked as an engineering consultant performing mechanical and nuclear engineering design calculations and analyses for various electric utility company power plants, both nuclear and fossil.

I began my employment with The Detroit Edison Company in 1995 as a System Engineer at the Fermi 2 Nuclear Power Plant. As a System Engineer, I was responsible for performing system monitoring and inspections, establishing predictive and preventive maintenance, identifying and implementing system modifications and enhancements, performing system testing, writing maintenance and operations procedures, and troubleshooting system problems. In 2000, I began a developmental assignment at Fermi 2 as the Balance of Plant, System Engineering Lead – Engineer, an assignment which was later made permanent. As the Lead Engineer, I was responsible for oversight of all of the Fermi 2 Balance of Plant systems and the direct supervision of several system engineers.

In 2004, I transferred to the Generation Optimization group. My areas of responsibility included analyzing 1-month or longer power purchases and sales, including summer capacity purchases, managing Detroit Edison's financial transmission rights (FTR) portfolio, assisting with the preparation of the Transmission and Midwest Independent Transmission System Operator (MISO) Energy Market Expense exhibits for Detroit Edison's Power Supply Cost Recovery (PSCR) cases in 2005, 2006, 2007, and 2008 and the 2006 Show Cause Case and the 2007 Detroit Edison general electric rate case, supporting the relevant witnesses in those Michigan Public Service Commission (Commission or MPSC) cases, managing Detroit Edison's resource adequacy requirements with the MISO, and preparing registration submittals for Detroit Edison's generation assets with the MISO. In 2007 I

Line No.

was promoted to Supervisor, Midterm Optimization.

Q. What are your duties and responsibilities in your current position?

A. My current responsibilities include development of the generation resource plan and procurement of capacity to meet reliability requirements, oversight of Detroit Edison's FTR portfolio, management of the Renewable Energy Certificate (REC) portfolio for the Company's voluntary GreenCurrents program, administration of the REC portfolio to address Public Act 295 of 2008 (the "clean, renewable, and efficient energy act"), management of emission allowance procurement, oversight of Detroit Edison's generation asset registration with the MISO, participation on MISO Subcommittees, as well as review and advocacy of Company recommendations regarding proposed MISO rules, regulations, and business practices.

Q. Have you previously provided testimony to the Commission?

A. Yes. I sponsored testimony in the following cases:

U-15002-R	2007 Power Supply Cost Recovery Plan Reconciliation
U-15417-R	2008 Power Supply Cost Recovery Plan Reconciliation
U-15677	2009 Power Supply Cost Recovery Plan
U-15677-R	2009 Power Supply Cost Recovery Plan Reconciliation
U-16047	2010 Power Supply Cost Recovery Plan
U-16356	2009 Renewable Cost Reconciliation

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to present the projections of Detroit Edison generation, emissions and associated emission allowance expense, and purchase power requirements and associated expense to be used to develop the Company's Power Supply Cost Recovery (PSCR) factor for 2011. In addition, I am supporting the 2012 through 2015 projection of the system generation, emissions and associated emission allowance expense, and purchased power requirements and associated expense required to serve Detroit Edison's anticipated full service load requirements. The system generation and purchase power projections I am presenting are for the electric requirements only, and do not include fuel for industrial send-out steam.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits:

Exhibit	Description
A-13	Projected Fuel, Net Purchased Power, and PSCR Expense, Years 2011-2015
A-14	Forecast of Plant Generation, Years 2011-2015
A-15	Summer Resource Plan, Years 2011-2015
A-16	Purchased Power, Sales, and Expense, Years 2011-2015
A-17	NO_x Ozone Season Emission Allowance Projections, Years 2011-2015
A-18	NO_x Annual Emission Allowance Projections, Years 2011-2015
A-19	SO_2 Emission Allowance Projections, Years 2011-2015

A-20 Urea and PAC Expense Projections, Years 2011-2015

Q. Were these exhibits prepared by you or under your direction?

A. Yes, they were.

Q. What expenses is the Company proposing to include in the PSCR factor?

A. As approved by the Commission in its January 11, 2010 Order in the Company's General Electric Rate Case No. U-15768, the PSCR expense forecast includes the fuel expense for electric generation, purchased and renewable power expense, revenue from wholesale power sales to third parties, NO_x emission allowance expense associated with generation, SO_2 emission allowance expense associated with generation, bundled transmission expenses, MISO energy market and ancillary services market (ASM) related costs, and urea expense. The bundled transmission expenses are those expenses forecasted to be incurred to serve Detroit Edison's full service load customers and do not include any transmission expenses incurred by alternative electric suppliers (AESs) to serve Electric Choice customers.

Q. Can you describe Exhibit A-13?

A. Exhibit A-13 is the Projected Fuel, Net Purchased Power, and PSCR expense forecast for the years 2011 - 2015. Shown on this Exhibit are the annual summaries of:

- Forecast generation as shown on Exhibit A-14 and the fuel (electric

Line No.

only) expense as shown on Exhibit A-2 and supported by Mr. Hoffman and Mr. Gailliez. Also shown are the forecasted Ludington Losses associated with the Ludington generation.

- The Net Purchased Power and Expense forecast from Exhibit A-16.
- The emission allowance expense projections for seasonal NO_X allowances for the years 2011 – 2015 from Exhibit A-17.
- The emission allowance expense projections for annual NO_X allowances for the years 2011 – 2015 from Exhibit A-18
- The emission allowance expense projections for SO_2 allowances for the years 2011 – 2015 from Exhibit A-19.
- The urea and powdered activated carbon expense projections from Exhibit A-20.
- The bundled transmission expense from Exhibit A-5.
- An expense adjustment for Federal Energy Regulatory Commission (FERC) wholesale firm sales.
- An expense adjustment for interruptible sales.
- A transmission expense adjustment for customers whose rates do not include the PSCR factor.
- The PSCR Fuel and Purchased Power Expense.

Q. What is the bundled transmission expense?

A. The bundled transmission expense is the projected transmission expenses to serve Detroit Edison's full service customer requirements as charged by MISO. Mr. Shields describes this expense and supports the expense projections.

Line No.

Q. What is the FERC Wholesale Firm Adjustment?

A. The Company has made long-term FERC jurisdictional wholesale for resale power sales to the Wolverine Power Supply Cooperative, Thumb Electric Cooperative, and the City of Detroit Public Lighting Department. The costs incurred to make these sales are excluded from the PSCR cost calculation. The cost for the firm portion of these sales is reflected in the FERC Wholesale Firm Adjustment.

Q. What is the Interruptible Adjustment?

A. The Interruptible Adjustment relates to the R-10 interruptible and D8/LCC8 interruptible in buy-out mode and the interruptible component of other tariffs such as Large Customer Contract (LCC) and FERC load. The resources allocated to serve this interruptible load are the higher cost resources from the system after the full service and FERC firm wholesale-for-resale load is supplied. These interruptible sales are not PSCR sales and are not included in determining recoverable PSCR expense. The Interruptible Adjustment is a credit of incremental expense to serve these interruptible sales. The price of the Interruptible Adjustment is estimated by multiplying the actual average interruptible price for 2009 by the ratio of the current on-peak market price projection for 2011 to the actual average on-peak market price in 2009.

Q. What is the Transmission Adjustment?

The Transmission Adjustment is a credit for transmission expenses the Company incurs by obtaining transmission service on behalf of the following customers whose rates do not include the PSCR factor; R-10, D8/LCC8 in buy-out mode, and LCC10 interruptible.

Q. Can you describe Exhibit A-14?

A. Exhibit A-14 is the forecast of the Company's plant generation for the years 2011 – 2015. I am supporting the annual generation forecast for all of the plants except Fermi 2. Witness Gailliez is supporting the Fermi 2 generation forecast.

Q. How were the annual projections of generation for each of the Company's power plants determined?

A. The projections for generation were developed utilizing PROMOD IV, which is a production cost simulation computer program. The program simulates the economic dispatch of the resources available to develop the generation projections, fuel consumption requirements and tons of emissions (which impacts emissions allowance expense). The heat requirements associated with the fuel consumption are then utilized by Mr. Hoffman to develop unit fuel cost and fuel expense.

The projections are for the Company's generating resources and do not include Michigan Public Power Agency's (MPPA) generation from the Belle River Power Plant.

Line
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Q. Does the Company anticipate any outages in excess of 90 days during 2011?

A. No. The Company does not have any scheduled outages that exceed 90 days during 2011.

Q. Can you describe Exhibit A-15?

A. Exhibit A-15 is the Company's summer resource plan to supply its adjusted peak demand including a planning reserve margin for the years 2011 through 2015. This resource plan is based on the Company's load forecast as presented in the testimony of Witness Ms. Siefman, the Company's owned generation resources, demand resources, and purchased capacity under contract to the Company.

Q. What is the Adjusted Peak Demand?

A. The Adjusted Peak Demand is the forecasted Detroit Edison full service customers' peak demand adjusted for the forecasted demand of the customers electing interruptible service under special contracts; R-10, D-8, LCC, interruptible tariff rates for air conditioners (IAC), interruptible tariff rates for water heaters, and D3.3, and further adjusted for long term wholesale sales that are included in the forecast.

Q. What is a Planning Reserve Margin?

A. A Planning Reserve Margin (PRM) is defined as the difference between available resources and peak demand, divided by the peak demand and expressed as a percentage. The Reliability*First* Corporation (RFC), of

Line No.

which Detroit Edison is a member, requires the Planning Coordinator to calculate a PRM for each planning year. As the responsible Planning Coordinator MISO established a minimum level of planning reserve requirements based on reliability principles and standards set forth by applicable Reliability Entities. These reliability principles and standards include performing a Loss of Load Expectation (LOLE) study that includes factors such as generator forced outage rates, generator planned outages, expected performance of load modifying resources, and load forecasting uncertainty. Load serving entities in MISO must have sufficient planning resources to meet their anticipated peak load requirements plus the PRM. The PRM established by MISO for the planning period June 2010 through May 2011 was 11.94%. The Company is assuming the same PRM of 11.94% for 2011 planning purposes because the PRM for the 2011 planning year will not be finalized until after the time of this filing.

Q. What is MISO's unforced capacity methodology?

A. MISO's unforced capacity methodology addresses the fact that not all generation resources contribute equally to resource adequacy. The unforced capacity (UCAP) value of a generation resource is determined by reducing its installed capacity (ICAP) by its equivalent forced outage rate demand (XEFORd) which is a measure of the probability that a generating unit will not be available due to forced outages or forced de-ratings when there is a demand on the unit to generate. The UCAP provides a means to recognize the relative contribution that each generation resource makes towards resource adequacy. MISO credits generating resources at their

Line No.

unforced capacity value for the purpose of meeting resource adequacy requirements.

Q. What are the total resources required by Detroit Edison to meet the resource adequacy requirement established by MISO?

A. The total resources required by the Company are the sum of the adjusted peak demand and the planning reserve margin. This is the amount of resources, installed available generation and purchased power, required to ensure adequate supply to serve the forecasted Detroit Edison peak demand requirement.

Q. What planning resources can the Company claim towards the resource adequacy requirement established by MISO?

A. The Company can claim its own generation resources at their UCAP value towards the resource adequacy requirement established by MISO. The Company expects that its generation resources will be credited with a UCAP value of 9,773 MW. This does not include the Marysville and Conners Creek power plants which are currently in suspended shutdown.

In addition to its own generation, the Company expects to have capacity rights from both PURPA/P.A.2 and Renewable Energy Contracts as shown on Exhibit A-15.

The Company expects to have a total of 9,860 MW of planning resources in

2011. Of these planning resources, 240 MW will be used to fulfill a long term wholesale sale, leaving 9,620 MW available to meet the Company's resource adequacy requirements.

Q. What are the changes in capacity of Company Owned Generation Resources shown on Line 21 of Exhibit A-15 in years 2014 and 2015?

A. Included in the Plan in years 2014 and 2015, are capacity increases associated with proposed efficiency upgrades to the Company's ownership portion of the Ludington Pumped Storage Station (one pump upgrade is shown in each year). Also, included in the Plan starting in year 2014, is a capacity reduction associated with auxiliary power usage from flue gas desulfurization units (a/k/a scrubbers) proposed for installation in late 2013 and early 2014 on Monroe Units 1 and 2. In addition, the Company is currently evaluating the retirement of some of its coal-fired generation units. The evaluations are in the early stages, so no plants that are assumed to supply energy in this case are anticipated to be retired during this PSCR Plan year.

Q. What are the Required Capacity Purchases shown on Exhibit A-15?

A. The Required Capacity Purchases are the forecasted amount of additional capacity needed to be acquired in order to achieve the amount of total resources required to serve Detroit Edison's forecasted adjusted full service customer peak demand including a planning reserve margin. The Company currently anticipates purchasing this capacity seasonally from the wholesale electric power market. The Company expects to purchase 520 MW of capacity for the summer of 2011.

At this time, forecasting to seasonally purchase capacity from the wholesale power market is the economic, reasonable and prudent decision given the uncertainties regarding the amount of Electric Choice load and market prices.

Q. Has the Company entered into capacity transaction purchases exceeding six months?

A. Yes. The Company has entered into capacity purchases exceeding six months from qualified small power producers as specified by PURPA, and from resource recovery facilities under existing contracts specified in 1989 P.A.2. The MPSC has approved the contracts for purchases from the following waste to energy facilities covered by P.A.2:

Facility	Case	Approved
Greater Detroit Resource Recovery	U-10066	8/14/92
Riverview Energy Systems	U-10068	8/14/92
Amended	U-10879	9/21/95
Sumpter Energy Associates (Station #1)	U-10069	8/14/92
Amended	U-10879	9/21/95
Wayne Energy Recovery	U-10070	8/14/92
Lyon Electric Generating	U-10232	2/23/93
Amended	U-10879	9/21/95
Turbine Power Limited Partnership - Arbor Hills	U-10594	8/03/94

Line No.

Amended	U-10879	9/21/95
Ann Arbor	U-10879	9/21/95

The Company has a contract for the purchase of capacity and energy from the Stoney Corners wind generation project first set forth in the Company's 2010 PSCR Plan which exceeds six months. The Company has also entered into renewable energy contracts exceeding six months for the purchase of capacity, energy, and renewable energy credits to comply with the Public Act 295 of 2008, all of which have been approved by the MPSC.

Q. Can you describe Exhibit A-16?

A. Exhibit A-16 provides the net purchased and renewable power and expense projections for the years 2011 through 2015.

Q. Can you describe the various types of purchases and sales shown on Exhibit A-16?

A. The types of purchases and sales shown on Exhibit A-16 are Wholesale energy purchases, summer capacity purchases, capacity and energy purchases from PURPA/P.A.2 Qualifying Facilities, renewable energy purchases (both Edison-generated renewable energy treated as purchased power from the Company's renewable energy plan, and renewable energy from Commission-approved renewable energy contracts), MISO Energy Market expenses, and wholesale energy sales.

Line No.

Q. What are wholesale power purchases and sales?

A. Wholesale power purchases are a projection of the weekly, daily and hourly purchases from wholesale market suppliers. Wholesale market suppliers include the MISO energy market, traditional utilities such as Consumers Energy, and Independent Power Producers.

Wholesale power sales are sales made by the Company to other utilities and wholesale power marketers under FERC-approved tariffs. The MISO began operation of its energy market on April 1, 2005, and the wholesale sales projections include sales by the Company into the energy market in excess of its native load (i.e. Detroit Edison's full service customers) and contract requirements. These wholesale sales do not include the Company's jurisdictionalized FERC wholesale-for-resale customers (Thumb Electric Cooperative, City of Detroit Public Lighting Department, and Wolverine Power Supply Cooperative).

Q. How were energy amounts and expenses for the economy purchases and sales from "Wholesale Market" developed?

A. The economy purchases and sales from the Wholesale Market were modeled in PROMOD based on projections of the wholesale electric market. The forward market curve for the Michigan Hub as of the close of business on July 30, 2010 was used as our estimate of forward market prices.

Q. Is the methodology used to develop the information for the projections of power generation and purchases and sales of power similar to that

used in previous filings with the MPSC?

A. Yes. The methodology is largely the same as that used in General Electric Rate Cases U-13808, U-15244, and U-15768, the Show Cause Case U-14838, and in the 2005, 2006, 2007, 2008, 2009, and 2010 Power Supply Cost Recovery Plan Cases U-14275, U-14702, U-15002, U-15417, U-15677, and U-16047. In this modeling, the wholesale hourly power market is developed from the wholesale forward power market prices. This modeling accommodates both purchasing and selling to the market on an hourly basis and provides a better reflection of the wholesale power market. The modeling also includes the regulated emissions projection from the Company's power plants.

Q. Are there any purchases included in the "MISO & Other" Wholesale Purchases on Exhibit A-16 that did not result from PROMOD modeling?

A. Yes. Included in the "MISO & Other" Wholesale Purchases is the purchase of energy and capacity from two 2.5 MW wind turbines at Stoney Corners Wind Farm (Stoney Corners) first set forth in the Company's 2010 PSCR Plan. Detroit Edison is purchasing Renewable Energy Credits (RECs) from Heritage Sustainable Energy (Heritage) for Detroit Edison's GreenCurrents program which supports Michigan-based renewable energy. The projected energy from Stoney Corners in 2011 is 13,578 MWh with an associated energy expense of about $937,000.

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Q. What are the Summer Capacity purchases and expenses?

A. The Required Capacity Purchases shown on Exhibit A-15 is the amount of capacity that the Company plans to purchase to ensure system reliability. For 2011, summer capacity purchases of 520 MW are projected to be required at an average cost of $1.69/kW-year.

Q. What are the PURPA/P.A.2 purchases shown on Exhibit A-16?

A. PURPA/P.A.2 purchases are the projections of energy that the Company purchases based on Commission approved contracts under sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 and 1989 P.A.2.

Q. What are the Renewable Energy purchases shown on Exhibit A-16?

A. The renewable energy purchases shown on Exhibit A-16 are the projections of renewable power purchases. This includes power from third party renewable energy generating sources and from Edison-owned renewable energy generating sources which are treated as purchased power from the Company's Renewable Energy Plan. The expense associated with each type of renewable energy purchase is based on the transfer price recommended in the Company's Renewable Energy Plan for the specific technology (MPSC Case No. U-15806-RPS; Exhibit A-8 (JHB-4) and 6T 1091-1103). It is important to note that renewable energy projects which are projected to come on line during 2013 and beyond will likely be subject to different transfer prices pursuant to the Company's to be filed 2011 renewable energy plan update.

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Q. What are the MISO Energy Market costs?

A. The MISO Energy Market costs are expenses the Company incurs as a MISO market participant. The costs associated with the MISO Energy Market as shown in Exhibit A-16 are those costs related to buying and selling energy in the MISO market, including the costs related to congestion and losses, Financial Transmission Rights, MISO market administrative fees, and other MISO charges and credits related to participating in the MISO energy market and ancillary services market. Witness Mr. Shields describes these expenses and supports the expense projections.

Q. What is the Company's environmental compliance strategy?

A. The Company has chosen to employ a strategy which is a combination of the installation of technology-based equipment and the purchase of emission allowances from the market.

Q. What is the Company's emission allowance purchase strategy?

A. Prior to 2009, the Company was procuring emission allowances sufficiently ahead of the expected need date so that adequate lead time existed to adjust the control technology construction schedule in the event of significant changes in the availability and/or the market prices of emission allowances. In July 2008, the D.C. Circuit Court vacated the Clean Air Interstate Rule (CAIR), but in December 2008 the court reversed itself and allowed the rule to remain in effect while the U.S. Environmental Protection Agency (EPA) attempts to fix the rule. Based on the uncertain status of CAIR, the Company has temporarily (and reasonably) suspended its prepurchase strategy. Emission allowances will be purchased for the current year need only, and purchase quantities will be spread over a number of months through the use of a “quantity/dollar cost averaging” concept to mitigate the potential cost impacts of price volatility in the emission allowance markets.

Q. What does Exhibit A-17 contain?

A. Exhibit A-17 displays the Company’s projection of NO_x “ozone season” (May – September) emission allowance expense for the years 2011 through 2015. Shown on Exhibit A-17 is the following information for the NO_x “ozone season” emission allowances: (1) the projected beginning balance of the Company’s emission allowances, (2) the emission allowances projected to be allocated to the Company, (3) the projection of emission allowance purchases by the Company, (4) the projected emission allowances to be consumed by the Company, (5) the projected ending balance of emission allowances and (6) the net expense of the projected emission allowance consumption for the relevant years.

The forecast shown on Exhibit A-17 indicates an additional purchase need of 3,548 “ozone season” NO_x emission allowances in 2011 with associated expense of $80,444. Total “ozone season” NOx emission allowances projected to be consumed in 2011 are 18,439 with an associated expense of $447,934.

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Q. What does Exhibit A-18 contain?

A. Exhibit A-18 displays the Company's projection of NO_x "annual" emission allowance expense for the years 2011 through 2015. Shown on Exhibit A-18 is the following information for the annual NO_x emission allowances: (1) the projected beginning balance of the Company's emission allowances, (2) the emission allowances projected to be allocated to the Company, (3) the projection of emission allowance purchases by the Company, (4) the projected emission allowances to be consumed by the Company, (5) the projected ending balance of emission allowances and (6) the net expense of the projected emission allowance consumption for the relevant years.

The forecast shown on Exhibit A-18 indicates a purchase need of 8,622 annual NO_x emission allowances in 2011 with associated expense of approximately $2.1 million. Total annual NO_x emission allowances projected to be consumed in 2011 are 42,205 with an associated expense of approximately $5.4 million.

Q. What does Exhibit A-19 contain?

A. Exhibit A-19 displays the Company's projection of SO_2 emission allowance expense for the years 2011 - 2015. Shown on Exhibit A-19 is the following information for the SO_2 emission allowances: (1) the projected beginning balance of the Company's emission allowances, (2) the emission allowances projected to be allocated to the Company, (3) the projection of emission allowance purchases by the Company, (4) the projected emission allowances to be consumed by the Company, (5) the projected ending balance of emission allowances and (6) the net expense of the projected emission allowance consumption for the relevant years.

SO_2 emission allowances of vintage years 2010-2014 will be surrendered at a 2 to 1 ratio of the actual SO_2 emissions. The SO_2 emission allowances of pre-2010 vintage will be surrendered 1 for 1. For emission allowances of vintage 2015 and beyond, SO_2 emission allowances will be surrendered at a ratio of 2.86 to 1. For the period after 2014, the pre-2010 vintage SO_2 emission allowances will continue to be surrendered at 1 for 1 and the 2010-2014 vintage SO_2 emission allowances will continue to be surrendered at 2 for 1.

The forecast shown on Exhibit A-19 indicates that there is no purchase need for SO_2 emission allowances in 2011. Total annual SO_2 emission allowances projected to be consumed in 2011 are 271,349 with an associated expense of $944,532 million.

Q. What does Exhibit A-20 contain?

A. Exhibit A-20 displays the Company's projection of incremental urea expense associated with operation of the Selective Catalytic Reduction ("SCR") units at the Monroe Power Plant. SCRs are currently installed at Monroe Units 1, 3, and 4. Monroe Unit 2 is projected to have a SCR installed in early 2014.

Exhibit A-20 also displays the Company's projection of activated carbon expense associated with mercury emissions reduction. The Company plans to use activated carbon to reduce mercury emissions for compliance with Michigan Rule 1503 (R 336.2503 Mercury emission standards for electric generating units).

Q. How is the Reduced Emissions Fuel (REF) Project, described by Witnesses Hoffman and Johnston, projected to effect emission expenses?

A. The REF Project will apply chemical additives to the coal burned at the Belle River and St. Clair Power Plants. Use of REF will result in reduced SO_2 emissions and reduced mercury emissions.

The SO_2 emissions are projected to be 3509 tons less in 2011 from the use of REF with an associated reduction in SO_2 allowance expense of $52,528 as shown on Exhibit A-19.

Starting in 2015, the Company plans to use both Standard Powdered Activated Carbon (PAC) and Brominated Activated Carbon (BrPAC) sorbents to reduced mercury emissions. BrPAC is projected to be substantially more expensive than PAC. The use of REF enables PAC to be substituted for BrPAC which reduces the overall mercury sorbent expense. In 2015, the reduction in mercury sorbent expense is projected to be $9.9 million with the use of REF as shown on Exhibit A-20.

The Company's additional expense associated with the use of REF will never exceed the financial benefits of reduced SO_2 and mercury emissions

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as described above, so there will never be a cost impact to PSCR customers.

Q. Does the use of Reduced Emissions Fuel at the Belle River Power Plant have an impact on any other expenses projected in your testimony or exhibits?

A. Yes. Since the fuel expense at the Belle River Power Plant is used in determining the following year's purchase power prices for the P.A.2. contracts, the increase in fuel expense due to the use of Reduced Emissions Fuel will result in a higher purchase power price. The REF price will be adjusted to ensure that this increased expense does not result in increased PSCR expense, all else being equal.

Q. Are the projections of Detroit Edison's emission allowances (NO_X and SO_2) and associated expenses reasonable?

A. Yes, the Company's emission reduction strategy and the projections of emission allowance expenses are reasonable and prudent. As shown on Exhibits Nos. A-17, A-18, and A-19, to supply the emission allowances consumed, the Company will utilize EPA-allocated emission allowances, emission allowances in inventory and emission allowances purchased from the market. Loans and swaps of emission allowances to third parties may continue to be utilized as a way to increase the value of Detroit Edison's emission allowance bank (by receiving additional allowances as interest for the loan/swap).

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Q. Is the projection of Detroit Edison's generation, purchased power, emissions and associated expenses reasonable?

A. Yes, the projection and expenses are reasonable and prudent. As has been previously described, the projection of Detroit Edison's generation and purchased power were developed from an economic dispatch forecast designed to reliably and economically serve the energy and demand requirements of the Company's customers based on fuel cost, electricity market costs, and emission allowance costs. The forecast was evaluated based on historical operation and expected changes due to maintenance schedules, fuel costs, market-based electricity prices and changes in Net System Output. The emissions were projected from the economic dispatch taking into account the market price of emission allowances required for generation. All relevant power supply elements were evaluated and reasonable and prudent projections were utilized to arrive at a reasonable and prudent power supply plan for Detroit Edison for 2011 and for the "out years" of 2012-2015.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
THE DETROIT EDISON COMPANY	)	
for Authority to Implement a Power	)	Case No. U-16434
Supply Cost Recovery Plan in its	)	
Rate Schedules for 2011 Metered	)	
Jurisdictional Sales of Electricity	)	

EXHIBITS

OF

ANGELA P. WOJTOWICZ

Michigan Public Service Commission
The Detroit Edison Company
Projected Fuel, Net Purchased Power, and PSCR Expense
Years 2011 - 2015

Case No.: U-16434
Exhibit: A-13
Witness: A. P. Wojtowicz
Page: 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Description**	**2011**	**2012**	**2013**	**2014**	**2015**
1						
2	Generation & Fuel					
3	- GWh	46,472	45,736	46,321	47,625	48,352
4	- $1,000	$ 986,250	$ 1,139,619	$ 1,261,964	$ 1,337,683	$ 1,434,687
5						
6	Ludington Losses					
7	- GWh	(598)	(551)	(513)	(492)	(478)
8						
9	Net Purchased & Renewable Power					
10	- GWh	1,721	383	(320)	(1,837)	(3,038)
11	- $1,000	$ 54,503	$ 22,002	$ 10,166	$ (45,463)	$ (114,356)
12						
13	Emission Allowances					
14	NOx Seasonal - $1,000	$ 448	$ 88	$ 103	$ 95	$ 88
15	NOx Annual - $1000	$ 5,388	$ 495	$ 321	$ 212	$ 250
16	SO2 - $1,000	$ 915	$ 3,501	$ 4,421	$ 937	$ 359
17						
18	Incremental Urea					
19	- $1,000	$ (25)	$ 655	$ 1,474	$ 3,249	$ 8,467
20						
21	Powdered Activated Carbon					
22	- $1,000					$ 23,908
23						
24	Net System Output					
25	- GWh	47,595	45,568	45,489	45,296	44,836
26	- $1,000	$ 1,047,478	$ 1,166,359	$ 1,278,450	$ 1,296,713	$ 1,353,403
27	- $/MWh	$22.01	$25.60	$28.10	$28.63	$30.19
28						
29	Bundled Transmission					
30	- $1,000	$264,779	$280,436	$278,819	$277,928	$271,429
31						
32	FERC Wholesale Firm Adjustment					
33	- GWh	3,046	676	669	662	667
34	- $1,000	$ 67,029	$ 17,311	$ 18,805	$ 18,955	$ 20,132
35						
36	Interruptible Adjustment					
37	Energy - GWh	880	842	841	837	829
38	- $1,000	$ 32,042	$ 31,958	$ 33,235	$ 34,476	$ 35,551
39						
40	Transmission Adjustment					
41	Energy - GWh	1,057	760	758	755	748
42	Transmission - $1,000	$ 6,260	$ 4,755	$ 4,724	$ 4,707	$ 4,603
43						
44	PSCR Fuel & Purchased Power					
45	- GWh	43,669	44,049	43,979	43,797	43,340
46	- $1,000	$1,206,927	$1,392,771	$1,500,505	$1,516,502	$1,564,545
47	- $/MWh	$27.64	$31.62	$34.12	$34.63	$36.10

Michigan Public Service Commission
The Detroit Edison Company
Forecast of Plant Generation
Years 2011 - 2015

Case No.: U-16434
Exhibit: A-14
Witness: A. P. Wojtowicz

	(a)		(b)	(c)	(d)	(e)	(f)
Line No.	**Plant**		**2011**	**2012**	**2013**	**2014**	**2015**
1							
2	Belle River[(1)]	GWh	6,827	6,589	6,802	7,166	7,211
3							
4	Fermi 2	GWh	9,579	8,913	8,931	9,732	8,927
5							
6	Greenwood	GWh	246	238	238	275	277
7							
8	Harbor Beach	GWh	27	23	23	27	26
9							
10	Monroe	GWh	16,417	16,463	16,877	17,247	18,197
11							
12	River Rouge	GWh	3,030	3,164	3,298	3,431	3,121
13							
14	St. Clair	GWh	6,993	7,184	6,896	6,890	7,269
15							
16	Trenton Channel	GWh	3,190	3,043	3,139	2,726	3,201
17							
20	Peakers	GWh	162	120	118	131	123
21							
22	Conners Creek	GWh	0	0	0	0	0
23							
24	Total System	GWh	46,472	45,736	46,321	47,625	48,352
25							
26	Ludington Generation	GWh	1,509	1,389	1,288	1,271	1,299
27	Ludington Pumping	GWh	2,107	1,940	1,801	1,763	1,777
28	Ludington Losses	GWh	(598)	(551)	(513)	(492)	(478)
29							
30	(1) DECo Ownership Share.						

Michigan Public Service Commission
The Detroit Edison Company
Summer Resource Plan
Years 2011 - 2015

Case No.: U-16434
Exhibit: A-15
Witness: A. P. Wojtowicz
Page: 1 of 1

Line No.	(a) Desription		(b) 2011	(c) 2012	(d) 2013	(e) 2014	(f) 2015
1	**Resource Plan Requirement**						
2							
3	Service Area Peak Demand	MW	11,477	11,174	11,085	10,991	10,851
4							
5	Electric Choice Load	MW	(919)	(919)	(919)	(919)	(919)
6							
7	Bundled Peak Demand	MW	10,558	10,255	10,167	10,072	9,932
8							
9	Demand Resources (Interruptible Load)	MW	(614)	(614)	(614)	(614)	(614)
10							
11	Long Term Wholesale Sale in Forecast	MW	(240)	-	-	-	-
12							
13	Adjusted Peak Demand	MW	9,704	9,641	9,553	9,458	9,318
14							
15	Planning Reserve Margin (UCAP Basis)	MW	437	434	430	426	420
16							
17	Total Required Resources	MW	10,141	10,075	9,983	9,884	9,738
18							
19	**Planning Resources**						
20							
21	Owned Generation Resources (UCAP)	MW	9,773	9,773	9,773	9,780	9,805
22							
23	Owned Renewable Generation Resources (UCAP)						
24	Wind	MW	-	7.2	7.2	14.7	14.7
25	Solar	MW	1.4	3.5	5.6	7.7	10.5
26							
27	Capacity Purchases (UCAP)						
28	PURPA	MW	70.9	70.9	70.9	70.9	70.9
29	Wind	MW	2.5	11.3	19.3	19.3	28.9
30	Landfill Gas & Biomass	MW	12.3	17.6	34.4	34.4	34.4
31							
32	**Total Planning Resources (UCAP)**	MW	9,860	9,884	9,911	9,927	9,964
33							
34	Long Term Wholesale Sale	MW	(240)	-	-	-	-
35							
36	**Available Planning Resources (UCAP)**	MW	**9,620**	**9,884**	**9,911**	**9,927**	**9,964**
37							
38							
39	**Required Capacity Purchases**	MW	**520**	**191**	**72**	**(42)**	**(226)**

Michigan Public Service Commission
The Detroit Edison Company
Purchased Power, Sales, and Expense
Years 2011 - 2015

Case No.: U-16434
Exhibit: A-16
Witness: A. P. Wojtowicz

	(a)	(b)	(c)	(d)	(e)	(f)
Line No.	**Description**	**2011**	**2012**	**2013**	**2014**	**2015**
1	**PURCHASES**					
2	**Wholesale Purchases**					
3	**MISO & Other**					
4	GWh	3,198	2,457	1,927	1,402	1,205
5	- $1,000	100,546	77,593	62,961	51,290	45,159
6	$/MWh	31.44	31.58	32.68	36.58	37.46
7						
8	**Seasonal Capacity**					
9	Capacity MW	520	191	72	0	0
10	- $1,000	$877	$819	$453	$0	$0
11	Premium $/kW-Yr	$1.69	$4.28	$6.28	$8.28	$8.28
12						
13	**PURPA/PA2**					
14	GWh	590	590	590	590	590
15	- $1,000	$31,969	$32,265	$32,568	$32,879	$33,198
16	$/MWh	$54	$55	$55	$56	$56
17						
18	**Renewable Energy Build**					
19	**Wind**					
20	MW	0.0	89.6	89.6	183.6	183.6
21	GWh	0.00	243.32	243.32	498.58	498.58
22	- $1,000	$0	$18,122	$18,604	$39,288	$41,482
23	$/MWh	$58.16	$74.48	$76.46	$78.80	$83.20
24						
25	**Solar**					
26	MW	2.0	5.0	8.0	11.0	15.0
27	GWh	2.28	5.69	9.11	12.53	17.08
28	- $1,000	$208	$708	$1,379	$2,290	$3,641
29	$/MWh	$91.44	$124.27	$151.35	$182.81	$213.13
30						
31	**Renewable Energy PPA**					
32	**Wind**					
33	MW	26.0	136.0	236.0	236.0	361.0
34	GWh	71	369	641	641	980
35	- $1,000	$4,106	$27,507	$49,002	$50,501	$81,564
36	$/MWh	$58.16	$74.48	$76.46	$78.80	$83.20
37						
38	**Landfill Gas / Biomass**					
39	MW	14.7	21.1	41.1	41.1	41.1
40	GWh	109.46	157.11	306.03	306.03	306.03
41	- $1,000	$6,720	$12,462	$25,627	$27,206	$29,324
42	$/MWh	$61.39	$79.32	$83.74	$88.90	$95.82
43						
44	**MISO Market Expenses**					
45	- $1,000	$7,422	$5,943	$4,771	$4,361	$2,990
46						
47	**TOTAL PURCHASES**					
48	**GWh**	**3970**	**3823**	**3716**	**3451**	**3598**
49	**- $1,000**	**$151,848**	**$175,418**	**$195,366**	**$207,817**	**$237,357**
50	**$/MWh**	**$38**	**$46**	**$53**	**$60**	**$66**
51						
52						
53						
54	**SALES**					
55	**Wholesale Spot Sales**					
56	GWh	2,250	3,440	4,036	5,288	6,636
57	- $1,000	$97,345	$153,416	$185,200	$253,279	$351,713
58	$/MWh	$43.27	$44.60	$45.89	$47.90	$53.00
59						
60	**TOTAL SALES**					
61	**GWh**	**2,250**	**3,440**	**4,036**	**5,288**	**6,636**
62	**- $1,000**	**$97,345**	**$153,416**	**$185,200**	**$253,279**	**$351,713**
63	**$/MWh**	**$43**	**$45**	**$46**	**$48**	**$53**
64						
65						
66						
67	**NET PURCHASES & SALES**					
68	**GWh**	**1,721**	**383**	**(320)**	**(1,837)**	**(3,038)**
69	**- $1,000**	**$54,503**	**$22,002**	**$10,166**	**-$45,463**	**-$114,356**
70	**$/MWh**	**$32**	**$57**	**-$32**	**$25**	**$38**

Michigan Public Service Commission
The Detroit Edison Company
NOx Ozone Season Emission Allowance Projections
Years 2011 - 2015

Case No.: U-16434
Exhibit: A-17
Witness: A. P. Wojtowicz

	(a)		(b)	(c)	(d)	(e)	(f)
Line No.	**Description**		**2011**	**2012**	**2013**	**2014**	**2015**
1							
2	Beginning Balance of Allowances	**Tons**	0	0	0	0	0
3							
4	DECo Annual Allocation From EPA (Excluding MPPA)	**Tons**	14,391	13,992	13,992	13,992	11,165
5							
6	Allowances Purchased Before Respective Vintage Year	**Tons**	500	-	-	-	-
7							
8	Purchase of Allowances	**Tons**	3,548	3,831	4,449	3,971	3,554
9							
10	Total Allowances Available	**Tons**	18,439	17,823	18,441	17,963	14,719
11							
12	Expected Allowances to be Consumed	**Tons**	**(18,439)**	**(17,823)**	**(18,441)**	**(17,963)**	**(14,719)**
13							
14	Ending Balance	**Tons**	0	0	0	0	0
15							
16							
17	Beginning Balance of Allowances	**$**	$ 20	$ 30	$ 2	$ 0	$ 0
18							
19	DECo Annual Allocation From EPA (Excluding MPPA)	**$**	$ -	$ -	$ -	$ -	$ -
20							
21	Allowances Purchased Before Respective Vintage Year	**$**	$ 367,500	$ -	$ -	$ -	$ -
22							
23	Purchase of Allowances	**$**	$ 80,444	$ 87,587	$ 103,404	$ 94,634	$ 87,985
24							
25	Total Allowances Available	**$**	$ 447,964	$ 87,617	$ 103,406	$ 94,634	$ 87,986
26							
27	Expected Allowances to be Consumed	**$**	**$ (447,934)**	**$ (87,615)**	**$ (103,406)**	**$ (94,634)**	**$ (87,983)**
28							
29	Ending Balance NOx Allowances Asset Account	**$**	$ 30	$ 2	$ 0	$ 0	$ 3
30							
31							
32	Average Cost of Consumed Allowances	**$/Ton**	**$ 24.29**	**$ 4.92**	**$ 5.61**	**$ 5.27**	**$ 5.98**

Michigan Public Service Commission
The Detroit Edison Company
NOx Annual Emission Allowance Projections
Years 2011 - 2015

Case No.: U-16434
Exhibit: A-18
Witness: A. P. Wojtowicz
Page: 1 of 1

Line No.	(a) Description		(b) 2011	(c) 2012	(d) 2013	(e) 2014	(f) 2015
1							
2	Beginning Balance of Allowances	**Tons**	0	0	1	0	0
3							
4	DECo Annual Allocation From EPA (Excluding MPPA)	**Tons**	32,292	32,292	31,291	31,281	25,571
5							
6	Allowances committed to before respective vintage year	**Tons**	1,250	-	-	-	-
7							
8	Purchase of Allowances	**Tons**	8,662	9,745	11,299	7,283	8,248
9							
10	Total Allowances Available	**Tons**	42,205	42,037	42,591	38,564	33,819
11							
12	Expected Allowances to be Consumed	**Tons**	**(42,204)**	**(42,037)**	**(42,590)**	**(38,564)**	**(33,818)**
13							
14	Ending Balance	**Tons**	0	1	0	0	1
15							
16							
17	Beginning Balance of Allowances	**$**	$ 420	$ 223	$ 8	$ 3	$ 2
18							
19	DECo Annual Allocation From EPA (Excluding MPPA)	**$**	$ -	$ -	$ -	$ -	$ -
20							
21	Allowance Purchases Committed to before Respective Vintage Year	**$**	$ 3,268,750	$ -	$ -	$ -	$ -
22							
23	Purchase of Allowances	**$**	$ 2,118,895	$ 495,102	$ 320,971	$ 212,145	$ 249,555
24							
25	Total Allowances Available	**$**	$ 5,388,065	$ 495,325	$ 320,979	$ 212,148	$ 249,557
26							
27	Expected Allowances to be Consumed	**$**	**$ (5,387,842)**	**$ (495,317)**	**$ (320,977)**	**$ (212,146)**	**$ (249,552)**
28							
29	Ending Balance NOx Allowances Asset Account	**$**	$ 223.31	$ 8.14	$ 2.98	$ 1.97	$ 4.97
30							
31							
32	Average Cost of Consumed Allowances	**$/Ton**	**$ 127.66**	**$ 11.78**	**$ 7.54**	**$ 5.50**	**$ 7.38**

Michigan Public Service Commission
The Detroit Edison Company
SO2 Emission Allowance Projections
Years 2011 - 2015

Case No.: U-16434
Exhibit: A-19
Witness: A. P. Wojtowicz

(a) Description		(b) 2011	(c) 2012	(d) 2013	(e) 2014	(f) 2015
Beginning Balance of Allowances	**Tons**	279,881	206,469	149,324	86,977	91,790
DECo Annual Allocation From EPA (Excluding MPPA)	**Tons**	204,445	204,445	204,445	204,445	204,445
Allowances Purchased before respective vintage year	**Tons**	-	17,000	12,500	-	-
Purchase of Allowances	**Tons**	-	-	-	-	-
Sale of Allowances	**Tons**	(6,509)	(6,598)	(6,591)	(6,940)	(18,650)
Swaps / Loans	**Tons**	-	131	-	-	-
Total Available Allowances	**Tons**	477,817	421,446	359,678	284,482	317,054
Expected Allowances to be Consumed	**Tons**	**(271,349)**	**(272,123)**	**(272,701)**	**(192,693)**	**(278,113)**
Ending Balance	**Tons**	206,469	149,324	86,977	91,790	38,941
Beginning Balance of Allowances	**$**	$ 1,685,880	$ 718,697	$ 1,886,208	$ 1,381,131	$ 435,016
DECo Annual Allocation From EPA (Excluding MPPA)	**$**	$ -	$ -	$ -	$ -	$ -
Allowances Purchased before respective vintage year	**$**	$ -	$ 4,688,210	$ 3,929,875	$ -	$ -
Purchase of Allowances	**$**	$ -	$ -	$ -	$ -	$ -
Sale of Allowances	**$**	$ (22,652)	$ (83,335)	$ (104,663)	$ (32,894)	$ (24,245)
Swaps / Loans	**$**	$ -	$ -	$ -	$ -	$ -
Total Available Allowance	**$**	$ 1,663,229	$ 5,323,572	$ 5,711,420	$ 1,348,237	$ 410,771
Expected Allowances to be Consumed	**$**	**$ (944,532)**	**$ (3,437,364)**	**$ (4,330,289)**	**$ (913,221)**	**$ (360,320)**
PSCR Credit From Sale of Allowances	**$**	$ 29,877	$ (63,211)	$ (91,020)	$ (23,734)	$ 1,492
Total PSCR Expense	**$**	$ (914,655)	$ (3,500,575)	$ (4,421,309)	$ (936,955)	$ (358,828)
Ending Balance SO2 Allowances Asset Account	**$**	$ 718,697	$ 1,886,208	$ 1,381,131	$ 435,016	$ 50,452
Average Cost of Consumed Allowances	**$/Ton**	**$ 3.48**	**$ 12.63**	**$ 15.88**	**$ 4.74**	**$ 1.30**
Emission Reduction from Reduced Emissions Fuel (REF)	**Tons**	3,255	3,299	3,295	3,470	6,521
Avoided Allowance Consumption from REF	**Tons**	6,509	6,598	6,591	6,940	18,650
Reduced Emissions Fuel SO2 Benefit	**$**	$ 52,528	$ 20,125	$ 13,643	$ 9,160	$ 25,737

Michigan Public Service Commission
The Detroit Edison Company
Urea and PAC Expense Projections
Years 2011 - 2015

Case No.: U-16434
Exhibit: A-20
Witness: A. P. Wojtowicz

Line No.	Description (a)		2011 (b)	2012 (c)	2013 (d)	2014 (e)	2015 (f)
1	**Urea**						
2	Cost of Delivered Liquid Urea (70% concentrate)	**$/Ton**	191	203	220	237	262
3	Cost of Urea per ton of NO_x removal	**$/Ton**	178	189	205	221	244
4	NO_x Removal at Monroe Units 1, 3, & 4 SCRs	**Tons**	42,166	43,339	43,928	48,714	65,625
5	Urea Expense	**$**	$ 7,503,301	$ 8,182,659	$ 9,002,573	$ 10,776,719	$ 15,994,635
6	Urea Expense in Base Rates	**$**	$ 7,528,120	$ 7,528,120	$ 7,528,120	$ 7,528,120	$ 7,528,120
7	Incremental PSCR Urea Expense	**$**	$ (24,819)	$ 654,539	$ 1,474,453	$ 3,248,599	$ 8,466,515
8							
9							
10	**Sorbent Expense for 90% or greater Mercury Reduction**						
11	Cost of Powdered Activated Carbon (PAC) per pound	**$/lb**					$ 0.60
12	Cost of Brominated Powdered Activated Carbon (BrPAC) per pound	**$/lb**					$ 1.20
13							
14	Sorbent Use for Mercury Reduction without Reduced Emissions Fuel (REF)						
15	Pounds of PAC to Achieve 90% or greater Mercury Capture Across Fleet	**lb**					19,339,439
16	Pounds of BrPAC to Achieve 90% or greater Mercury Capture Across Fleet	**lb**					18,514,140
17	Total Sorbent Expense	**$**					$ 33,820,632
18							
19	Sorbent Use for Mercury Reduction with Reduced Emissions Fuel (REF)						
20	Pounds of PAC to Achieve 90% or greater Mercury Capture Across Fleet	**lb**					39,847,410
21	Pounds of BrPAC to Achieve 90% or greater Mercury Capture Across Fleet						-
22	Total Sorbent Expense	**$**					$ 23,908,446
23							
24	Reduced Emissions Fuel Mercury Benefit	**$**					$ 9,912,186

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
THE DETROIT EDISON COMPANY	)	
for Authority to Implement a Power	)	Case No. U- 16434
Supply Cost Recovery Plan in its	)	
Rate Schedules for 2011 Metered	)	
Jurisdictional Sales of Electricity	)	

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

JAMES J. MUSIAL

Line No.

Q. What is your name, business address and by whom are you employed?

A. My name is James J. Musial. My business address is: One Energy Plaza, Detroit, Michigan 48226. I am employed by DTE Energy Corporate Services, LLC within Regulatory Affairs as Manager of Federal Regulatory Affairs

Q. On whose behalf are you testifying?

A. I am testifying on behalf of The Detroit Edison Company (Detroit Edison, Edison or Company).

Q. What is your educational background?

A. I graduated from Michigan Technological University in 1976 with an Associate Degree in Civil Engineering. In 1984, I received a Bachelor of Science Degree in Construction Engineering from Lawrence Institute of Technology. In January 2005, I received a Master of Arts Degree in Economics from Walsh College.

Q. What is your DTE Energy work experience?

A. I began work with the Company in 1977 as a cartographer in the Architectural/Civil group. In 1978, I took a position as Assistant Engineering Technician in System Construction. In late 1979, I was promoted to Associate Engineering Technician in the Regulatory Affairs organization and have since held positions of increasing responsibility within that organization.

Q. What is your current position with the Company?

A. My current position is Manager – Federal Regulatory Affairs. In this position, I have the overall responsibility of managing the activities and resources pertaining to regulatory filings and proceedings before the Federal Energy Regulatory Commission (FERC), as well as regulatory developments related to the operation and initiatives of the Midwest Independent Transmission System Operator, Inc. (Midwest ISO or MISO). I have held this position since June 2004.

Q. Have you completed other courses of study or attended any professional seminars?

A. Yes, I have attended short courses on power systems engineering, as well as utility accounting and ratemaking.

Q. Have you previously sponsored testimony before the Michigan Public Service Commission?

A. Yes, I presented testimony before this Commission in the following dockets:

Case No. U-10176	Experimental Retail Wheeling
Case No. U-11452	Retail Access Service
Case No. U-12980	Ford Motor and Rouge Steel Complaint
Case No. U-13286	Electric Rate Unbundling
Case No. U-14702	2006 PSCR Plan

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Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide an overview of certain issues that are being addressed by FERC or that are jurisdictional to FERC that may impact the cost of services provided by the Midwest ISO to Detroit Edison and its customers whose bills include a Power Supply Cost Recovery charge. I will address Detroit Edison's activities directed to those issues.

Q. What Federal Energy Regulatory Commission related activity do you address in your testimony?

A. There are four issues that I will discuss in my testimony that have the potential to substantively affect the cost of services provided by the Midwest ISO to Detroit Edison and its customers during the 2011 through 2015 PSCR forecast period. They are:

- The Midwest ISO's proposal to establish a new MVP transmission planning and cost allocation category
- The Midwest ISO's review of qualifying criteria associated with transmission projects that provide economic value (RECB III Phase 3)
- MISO's Transmission Expansion Plan (MTEP 10)
- The Midwest ISO's stakeholder process addressing generation resource adequacy requirements

MVP Transmission Planning and Cost Allocation

Q. What developments have there been, if any, with respect to the Midwest ISO's tariff addressing how the cost of transmission projects will be recovered from transmission customers within its footprint?

A. The Company has been concerned about how the need for transmission development to support potential wind generation sited remotely from load would ultimately be resolved by the Midwest ISO and FERC. Detroit Edison believes that the latest proposals developed by MISO will lead to unacceptable results as compared to the current FERC-approved cost allocation methodologies as detailed in Attachment FF to the Midwest ISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (ASM Tariff).

Concerns about dealing with potential wind interconnections led MISO to reconvene the RECB[1] Task Force to develop proposed amendments to the MISO's FERC-approved tariff as necessary. The RECB III Task Force efforts were separated into three phases with the goal of submitting a proposal to FERC seeking to modify, or replace as appropriate, portions of Attachment FF of MISO's tariff at the end of each phase of the process. Phase 1 and 2 are complete and Phase 3 began in late September, 2010.

Q. What was the focus of Phase 1 of the RECB III Task Force review process?

A. Phase 1 focused on near-term solutions to the Generator Interconnection Project (GIP) cost allocation methodology under Attachment FF, which

[1] (Regional Expansion and Criteria Benefits) RECB I was convened to address cost allocation issues associated with transmission projects to address NERC reliability requirements. RECB II was convened to address cost allocation issues associated with transmission projects designed to deliver economic benefits. RECB III was convened to address three separate issues which are discussed later in my testimony as RECB III Phase 1, 2 and 3.

allocated transmission network upgrade costs to generators and load on a 50/50 basis. There was a concern that this allocation methodology disproportionately burdened the customers in the transmission pricing zones where large amounts of wind generation may seek interconnection, particularly in view of the fact that these resources were often being developed to serve load in the distant major MISO load centers and not to serve the local customers. This was particularly true in the case of generation intending to connect to the transmission system of Otter Tail Power where the amount of generation seeking interconnection exceeded the existing load on the Otter Tail system. Otter Tail argued that the 50/50 sharing of transmission network upgrade costs was unreasonable, particularly in view of the fact that its customers were not getting any direct benefits from the generation seeking to locate in their pricing zone.

MISO made a filing to FERC on July 9, 2009 proposing to allocate 90% of 345kV network upgrade costs to the interconnecting generator with the remaining 10% to be shared across the entire MISO region. Costs associated with projects less than 345kV were to be recovered 100% from the interconnecting generator. On October 23, 2009, FERC issued an order accepting this solution on an interim basis and ordered MISO to work with stakeholders to develop and propose a permanent solution by July 15, 2010.

Q. What was to be included in Phase 2 of the RECB III Task Force review process?

A. The RECB Task Force started Phase 2 discussions in late September

Line No.

2009 to develop a permanent solution to the issue addressed in the tariff revisions coming out of Phase 1 and to develop a transmission cost allocation methodology that would address the integration of large quantities of generation located remotely from load proposed to be developed to address existing and emerging renewable energy legislation. In addition to the efforts underway by the RECB Task Force, the state regulators who make up the Organization of MISO States (OMS) indicated that they wanted to take a lead role in these discussions and formed the Cost Allocation Regional Planning (CARP) workgroup within their ranks for that purpose.

Q. Did Detroit Edison participate in the RECB III Task Force discussions?

A. Yes. The Company was represented throughout the process.

Q. What cost allocation proposals did MISO initially promote during the RECB III Task Force discussions?

A. MISO Planning Staff initially proposed that any new cost allocation methodology would:

- Be applied to all future projects: reliability and economic projects as well as forward-looking projects intended to accommodate existing and future renewable energy legislation.
- Allocate costs to both new and existing generators (based on their *injections* into the grid) and also to load serving entities (based on

Line No.

their *withdrawals* from the grid – referred to as the Injection/Withdrawal concept).

- Under the initial Injection/Withdrawal concept cost allocations would be handled differently among three defined “pricing layers” (Regional, Subregional, and Local) to more closely reflect that the assumption that benefits of building lower voltage transmission lines would be seen more at a “local” level than across the entire MISO footprint.

Q. Did Detroit Edison fully support MISO’s initial proposal?

A. No. Detroit Edison initially proposed that any transmission cost allocation associated with transmission projects intended to address legislated Renewable Portfolio Standards (RPS) requirements be funded solely by the renewable-sourced generation utilizing those projects. The generators in turn would recover their transmission costs via Purchase Power Agreements from the load purchasing the renewable power and “benefitting” from the expansion. Detroit Edison also supported the position that minimally, any cost allocation formula should contain an allocation defined by the regional, subregional and local layers.

Q. What cost allocation proposal did the MISO Transmission Owners promote?

A. A group of “Supporting Transmission Owners” (excluding the ITC companies) proposed:

- That the costs for Unique Purpose Projects (UPP) be assigned 100% to load on a regional level under a “postage stamp” allocation methodology.

- UPP projects were defined as those designed to accommodate Federal or State renewable energy legislation.
- The current RECB I and II approaches for handling reliability and economic projects, respectively, would continue.

Detroit Edison did not support this proposal because in its view the broad allocation of transmission development cost provides no assurance that the load or entities causing the cost to be incurred and benefitting from the development would be apportioned a share of the cost commensurate with the benefits it would expect to receive. It is Detroit Edison's view that for any new transmission project the assigned costs should be roughly commensurate with benefits realized.

Q. What cost allocation proposal did the ITC companies promote during the RECB process?

A. The ITC companies and the Midwest ISO Independent Power Producer/Power Marketer Sectors supported a Highway/Byway Proposal similar to that recently approved by FERC for application in the Southwest Power Pool (SPP). Under the Highway/Byway approach transmission costs are allocated differently based on the transmission voltage level, with the larger voltage projects (i. e., 765 kV) allocated regionally, and the smaller projects (i.e, 120 kV) allocated locally

Like the Transmission Owner's proposal, Detroit Edison did not support this proposal because in its view the broad allocation of transmission development cost provides no assurance that the “right” load would be charged for the system and that assigned costs would be commensurate with benefits realized.

Q. What cost allocation proposal was put forth by the Organization of MISO States CARP group?

A. The CARP group developed a proposal that was similar to the Transmission Owners’ proposal described earlier that would socialize costs associated with UPP. Under the CARP proposal:

- Transmission projects developed to garner economic benefits were to be cost shared in the same manner as UPPs.
- Cost allocation approach for reliability projects would remain unchanged from the current tariff.
- Generators would pay 20% of costs associated with UPPs. (The main difference between the CARP proposal and the Transmission Owners’ proposal is that CARP proposed to assess a charge to generators.)

The CARP proposal evolved over the discussion period in response to input from MISO’s western states from a proposal containing a “layered” cost allocation approach to one where all costs would be allocated broadly across the region. Detroit Edison favored the CARP proposal when it included an allocation of some portion of transmission cost to the local and sub-regional layers, and did not simply postage stamp all costs across the

Line
No.

MISO footprint on a regional level.

Q. What cost allocation methodology did the Midwest ISO ultimately submit to FERC on July 15, 2010 in compliance with FERC's October 23, 2009 order?

A. The Midwest ISO submitted a proposal addressing the cost allocation for a new category of transmission projects referred to as "Multi Value Projects" or MVPs. MVPs are defined as having the following characteristics:

- Support delivery of energy from future generation resources addressing state and federal renewable energy legislation,
- Resolve multiple Transmission Value Issues (e.g. reduced production cost, locational marginal prices) within multiple pricing zones,
- Resolve at least one unique Transmission Value Issue and Transmission Compliance Issue.

With regard to cost allocation associated with MVP projects MISO proposed:

- To socialize on a "postage stamp" basis 100% of the revenue requirement of an MVP to load and exports on an energy (MWh) basis
- That the generation interconnection project cost sharing methodology would remain unchanged from the current tariff:
- The ITC companies and ATC continue to fully fund network upgrades resulting from generator interconnection requests. These costs are then rolled into their zonal transmission rates.
- In other transmission pricing zones: 10% of 345kV and above

facilities allocated to load with 90% allocated to the interconnecting generator. Costs for network upgrades necessitated by generator interconnections at voltages less than 345kV are to be allocated totally to the generator.

The Midwest ISO proposal continues the existing cost allocation for RECB I Baseline Reliability and for RECB II Economic projects. The benefit metrics to be considered when evaluating Economic projects will be reviewed during Phase 3 of the RECB III stakeholder process which began in late September 2010. The Midwest ISO has requested that FERC act on its application by mid-December 2010.

Q. Did Detroit Edison respond to the Midwest ISO's July 15, 2010 FERC filing made under Docket ER10-1791?

A. Yes. On September 10, the Detroit Edison Company, Michigan Attorney General Michael A. Cox, ABATE, Consumers Energy, the Michigan Municipal Electric Association and the Michigan Public Power Agency (jointly, the "MISO Northeast Transmission Customers"), submitted their Protest and Request for Hearing in response to MISO's July 15th FERC filing.

As previously discussed, the Midwest ISO has proposed to allocate 100% of the costs of "multi-value" transmission projects to load and exports on a "postage-stamp" basis. Multi-value projects (MVPs) have been defined by the Midwest ISO as those that integrate renewable energy resources or other generating resources driven by state or federal energy legislation. The Midwest ISO has also defined MVPs as projects that can provide economic efficiencies by reducing congestion or reserve margins across the region while at the same time improving regional reliability.

The MISO Northeast parties have protested that those portions of the Lower Peninsula of Michigan located within the Midwest ISO footprint (*i.e.,* “MISO Northeast”)[2] are unique within the Midwest ISO, and as such, should be designated by FERC as a separate area for transmission planning and cost allocation purposes. In particular, the protest is based on the fact that Michigan has enacted legislation[3] establishing a Renewable Portfolio Standard of 10% by the year 2015, which includes a transmission certification process that is unique in the Midwest ISO footprint. With minor exception, renewable generation projects constructed pursuant to PA295 must be sited within Michigan. MVP projects developed outside of the MISO Northeast zone will be of little benefit in enabling the MISO Northeast Transmission Customers to address with this Michigan energy legislation. As a result, the Midwest ISO proposal would impose significant costs on the MISO Northeast Transmission Customers, who will receive little, if any, corresponding benefit.

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[2] MISO Northeast is defined as the Midwest ISO transmission systems that are essentially islanded from the other Midwest ISO regions after the withdrawal of American Transmission Systems, Inc (“ATSI”) from the Midwest ISO in 2011. MISO Northeast encompasses the transmission facilities of: ITC*Transmission*; Michigan Electric Transmission Company. LLC (“METC”); Wolverine Power Supply Cooperative, Inc. (“Wolverine”); Michigan Public Power Agency (“MPPA”); Traverse City Power and Light (“Traverse City”); Zeeland Board of Public Works (“Zeeland”); Grand Haven Board of Light and Power (“Grand Haven”) and the Michigan South Central Power Agency. (see Protest and Request for Hearing of MISO Northeast Transmission Customers under ER10-1791)

[3] The “Clean, Renewable, and Efficient Energy Act”, Act 295 of 2008

Line No.

In addition to the issue that Michigan will not be able to utilize MVP projects developed outside of Michigan to address Act 295's renewable energy, capacity and credit standards, the MISO Northeast parties argue that there are a number of flaws in the proposal that are more global in nature including the fact that the Midwest ISO proposal would allocate costs regionally for projects that have previously been designated as serving only a local purpose. The Midwest ISO proposal further violates FERC cost-causation principles and court precedents by assigning costs that will not be "roughly commensurate" with the benefits that Michigan transmission customers will realize from the proposed MVP projects. Finally, the Midwest ISO's MVP proposal would result in Michigan's electric customers subsidizing the development of out-of-state renewable projects that will not only fail to provide Michigan's customers with any substantive level of benefit, but will also compete with the development of a wind generation development industry in Michigan.

Q. What are the potential cost impacts to the Company's customers that may result from the Midwest ISO MVP cost allocation proposal?

A. On August 19, 2010, the Midwest ISO Board of Directors authorized the development of ITC Transmission's proposed 345 kV Thumb Loop project. ITC has estimated that the project will cost $510 million. MISO has included this project in its MTEP10 report indicating an in-service date of 2015 and reflecting an expected impact on transmission rates beginning in 2015. Mr. Shields has reflected this cost impact in his estimate of 2015 transmission

Line
No.

expenses. (See Exhibit A-5). This project is the subject of MPSC Case No. U-16200.

Q. Are there additional MVP projects that may potentially result in cost impacts to the Company's customers if the Midwest ISO MVP cost allocation proposal is approved by FERC?

A. Yes. In 2008, the MISO initiated a targeted transmission study, called the Regional Generation Outlet Study (RGOS), to address transmission that might be needed to support potential state and federal renewable energy legislation. The RGOS study seeks to address the integration between longer term (MTEP) and shorter term (generator interconnection queue) planning processes. Results of the RGOS study have been incorporated into the MTEP10 analysis and results. As described in the MTEP10 report, the RGOS planning team narrowed their focus to the development of three (3) transmission expansion scenarios to integrate wind in designated zones within the MISO footprint: (1) a Native Voltage overlay that does *not* introduce new technology or voltages in the area; (2) a 765 kV overlay allowing the introduction of 765 kV transmission throughout the study footprint; and (3) Native Voltage with DC transmission that allows for the expansion of DC technology within the study footprint.

The three transmission overlay plans represent potential expenditures of $16 Billion to $22 Billion in 2010 dollars and $21 Billion to $27 Billion in 2019 dollars for transmission over the next 20 years and would add between 6,400 miles to 8,000 miles of new transmission infrastructure. A sub-set of these projects have been identified as MVP "starter" projects in the Midwest ISO's July 15, 2010 filing in docket ER10-1791. As explained in MTEP10, it is the through the RGOS process that Midwest ISO has identified a set of "starter" projects that meet standards established by current renewable energy legislation. Viable for near-term development, these starter projects represent $5.8 Billion (2010 dollars) of capital expenditures, approximately $4.4 Billion in the Midwest ISO footprint with the remainder in PJM. The Thumb Loop project was identified as one of the initial "starter" projects and is the only project reflected in MISO's projection of future transmission rates. The evaluation of **candidate MVP projects to be considered within the MTEP11 planning cycle began with a MVP Portfolio Technical Studies Task Force Kickoff Meeting held on September 23, 2010. Because the Midwest ISO has proposed to broadly allocate the costs of MVP projects across load in its footprint, Detroit Edison will actively participate in these stakeholder discussions.**

RECB III Phase 3

Q. What was the focus of Phase 3 of the RECB III Task Force review process?

A. The Phase 3 evaluation began on September 21, 2010 and will address the quantification of benefits associated with projects that are not necessarily required reliability projects but may provide broad economic benefits. This is an important discussion because projects that are deemed to provide "economic value across multiple pricing zones with a

Line No.

total benefit-to-cost ratio of 1.0 or higher" meet the criterion proposed for being designated an MVP subject to regional cost sharing under the Midwest ISO's July 15, 2010, tariff proposal. The current benefit-to-cost ratio to enable cost sharing of an "economic" project is up to 3.0 with a limited set of benefit metrics to be considered. If the set of benefit metrics is expanded with the lower benefit-to-cost hurdle, then many more of these projects will potentially be designated as MVPs eligible for cost sharing across the Midwest ISO footprint. Detroit Edison will be represented during these stakeholder proceedings.

MISO's Transmission Expansion Plan (MTEP10)

Q. What is the framework under which MISO examines the need for transmission system expansions?

A. MISO initiates an annual study, referred to as the MISO Transmission Expansion Plan ("MTEP"), examining projected constraints and other issues related to the transmission system, particularly those that might lead to violations of NERC transmission reliability criteria, and evaluates possible solutions. The 2010 development of the transmission expansion plan, referred to as MTEP10, began the stakeholder review process in December 2009. The MTEP stakeholder review process is divided into sub-regions, with the Company's service territory being located in the Eastern Sub-Region. Company personnel participated in all three of the Eastern Sub-Regional Planning Meetings ("SPMs"), which were held on December 8, 2009, March 31, 2010, and June 21, 2010. In addition to these planning meetings, Company personnel also participated in the three Michigan Technical Study Task Force Meetings, which were arranged to augment the SPMs and to address the issues related to Michigan-specific MTEP projects. These meetings were held on May 20, 2010, June 11, 2010 and July 9, 2010.

Q. Why is the stakeholder review process important?

A. While not perfect, the stakeholder review process is important because it facilitates the information exchange amongst the affected parties, which contributes to the goal of optimizing any proposed transmission expansion plans. The recent economic slowdown has led to a decline in load which has resulted in some expansion projects being postponed or cancelled. Because of the collaborative nature of the SPMs and the Michigan Technical Study Task Force, the scope of the proposed MTEP10 for the Company's electric service area was able to be updated to reflect these changed circumstances. The change of scope in the MTEP10 for the Company's electric service area resulted in a deferment or cancellation of some projects that were included in the first draft of the plan.

<u>Generation Resource Adequacy</u>

Q. Are there on-going Midwest ISO stakeholder initiatives that may result in modification to the Midwest ISO's current Resource Adequacy construct?

A. Efforts to develop an RTO-driven resource adequacy plan began in 2004 when FERC directed the Midwest ISO to develop such a plan for ensuring

Line
No.

resource adequacy. The first resource adequacy construct was put in place in late 2006. In compliance with several FERC directives issued since that time, the Midwest ISO has made several amendments to its tariff, the most recent being to incorporate a provision that, subject to state regulatory review and acceptance, would enable demand response resources to participate in the monthly auction of capacity available to load serving entities to ensure that they have adequate resources to cover designated reserve margins. Resource Adequacy provisions are contained in Module E of the Midwest ISO's ASM Tariff. Currently under Module E, the Midwest ISO conducts a voluntary auction at the end of each month allowing generators with excess uncommitted capacity to sell, and allowing load serving entities to buy capacity to enable the load serving entities to meet a reserve requirement that is common across the Midwest ISO footprint. If load serving entities are found to be capacity deficient, the Midwest ISO assigns a capacity deficiency charge (Financial Settlement Charge to Capacity Deficient LSEs) that is derived from a seasonally adjusted, $95,000 per MW capacity price which approximates what the Midwest ISO calculates to be the cost of new generation entry, or CONE.

In a June 2010 order, FERC reiterated a directive contained in a February 2009 rehearing order that it expected the Midwest ISO and its stakeholders to develop a plan for incorporating a locational capacity requirement into the resource adequacy plan. FERC directed that a compliance filing be made on this issue by December 8, 2010. The Midwest ISO and its stakeholders are developing a proposal that would redefine the current reserve requirement that applies equally across the footprint to a set of reserve requirements that will apply on a more localized basis. The new locational capacity requirements are expected to start with the 2012-2013 planning year, which starts in June 2012.

On a parallel and more contentious path, the Midwest ISO and its stakeholders are developing a plan that would alter the current monthly capacity reserve auction to one that appears at this time will require load serving entities to demonstrate either through bilateral purchase or through participation in a forward Midwest ISO capacity auction that they have adequate resources to meet their planning reserve margin requirements for between three and five years in advance. The exact forward time period is still being debated. At this point the Midwest ISO is proposing that this new resource adequacy construct start with the 2012-2013 planning year (starts in June 2012) and is working towards making a tariff application in conjunction with its December 8, 2010 compliance filing addressing the previously discussed locational capacity requirements.

Q. How could either of these resource adequacy filings impact the Company's 2011 PSCR Plan year or future PSCR plan years as detailed in the this 2011 PSCR Plan filing?

A. As previously noted, MISO's proposal to address FERC's directive that its resource adequacy construct address locational capacity requirements is expected to be effective for the 2012-2013 planning year. If approved by FERC, there will be no impact on Detroit Edison's 2011 PSCR Plan.

However, depending on how the locational reserve requirements are established, Detroit Edison may be required to purchase more or less summer capacity to meet its capacity reserve requirements. Because the outcome of this proposal is uncertain, no reflection of it has been made in this PSCR Plan filing.

With regard to the Midwest ISO potentially amending its current monthly capacity auction to a three to five year forward auction, if approved by FERC, there will be no impact on Detroit Edison's 2011 PSCR Plan year but PSCR plan years following 2011 could be affected.

As previously noted, it is expected that the Midwest ISO proposal addressing the forward procurement of capacity will be proposed to start with the 2012-2013 planning year, which starts in June 2012. This may mean that Detroit Edison would need to begin procuring capacity for 2012, 2013 and 2014 as early as October 2011. Because the outcome of this proposal is uncertain, no reflection of it has been made in this 2011 PSCR Plan filing.

Q. Does this complete your direct testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of THE DETROIT EDISON COMPANY for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules For 2011 Metered Jurisdictional Sales Of Electricity	)))))))	Case No. U-16434 (Paperless e-file)

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF WAYNE)

ESTELLA R. BRANSON, being duly sworn, deposes and says that on the 30th day of September, 2010, a copy of The Detroit Edison Company's 2011 PSCR Plan Application, and Testimony and Exhibits of Mses. Sherrie L. Siefman and Angela P. Wojtowicz and Messrs. Robert A. Gailliez, Michael G. Hoffman, Kenneth D. Johnston and Michael W. Shields and Testimony of Mr. James J. Musial in the above captioned matter was served upon the persons on the attached service list via e-mail.

Estella R. Branson

Digitally signed by Estella R. Branson
DN: cn=Estella R. Branson, o=DTE - Regulatory Affairs, ou=DTE - Regulatory Affairs, email=bransone@dteenergy.com, c=US
Date: 2010.09.30 16:52:45 -04'00'

ESTELLA R. BRANSON

Subscribed and sworn to before
me this 30th day of September, 2010

Jennifer Evans

Digitally signed by Jennifer Evans
DN: cn=Jennifer Evans, o, ou=Regulatory Affairs, email=evansj2@dteenergy.com, c=US
Date: 2010.09.30 16:55:30 -04'00'

Notary Public

MPSC Case No. U-16434
September 30, 2010
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