The Detroit Edison Company
2000 2nd Ave., Detroit, MI 48226-1279

Detroit Edison
A DTE Energy Company

Jon P. Christinidis
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September 30, 2008

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

Re: In the matter of the Application of The Detroit Edison Company for Authority to Implement a Power Supply Cost Recovery Plan In Its Rate Schedules for 2009 Metered Jurisdictional Sales of Electricity
MPSC Case No. U-15677 (Paperless e-file)

Dear Ms. Kunkle:

Attached for electronic filing is The Detroit Edison Company's 2009 PSCR Plan Application, proposed Notice of Hearing, and Testimony and Exhibits of Ms. Sherrie L. Siefman and Angela P. Wojtowicz and Messrs. Robert A. Gailliez, James D. Good, Kenneth D. Johnston, and Michael W. Shields and Testimony of James A. Brunell in the above-referenced case. Also attached is a Proof of Service.

Very truly yours,

Jon P. Christinidis

Digitally signed by Jon P. Christinidis
DN: cn=Jon P. Christinidis, o=DTE Energy, ou=Legal-Regulatory Affairs, email=christinidisj@dteenergy.com, c=US
Date: 2008.09.30 16:30:01 -04'00'

Jon P. Christinidis

JPC/kbt
Attachments
cc: Service List

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of THE DETROIT EDISON COMPANY for Authority to Implement a Power Supply Cost Recovery Plan in its Rate Schedules For 2009 Metered Jurisdictional Sales Of Electricity.	)))))))	Case No. U-15677

2009 PSCR PLAN APPLICATION OF THE DETROIT EDISON COMPANY

The Detroit Edison Company ("Applicant," the "Company," or "Detroit Edison"), a corporation organized and existing under and by virtue of the laws of the State of Michigan, with its principal office at 2000 Second Avenue, 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"); R 460.17101 *et seq*.; and relevant Commission orders, a Power Supply Cost Recovery ("PSCR") plan in its rate schedules for 2009 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, and U-15417, spanning the PSCR years 2004, 2005, 2006, 2007, and 2008. *See also,* In *re Application of Detroit Edison Co*, 276 Mich App 216; 740 NW2d 685 (2007); *Attorney General v Public Service Commission*, unpublished opinion per curiam of the Court of Appeals, decided August 2, 2007 (Docket No. 265869) (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 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. Approving the inclusion of the Company's 2008 PSCR underrecovery in Detroit Edison 2009 PSCR Factors is in the public interest because the

sooner this underrecovery is collected, the less interest customers will be required to pay Detroit Edison pursuant to MCL 460.6j(16).

6. Applicant is hereby filing its 2009 PSCR Plan in this docket and is seeking Commission approval to include a PSCR Factor of 17.29 mills per kWh in commercial and industrial customers' bills for the period January 1, 2009 through December 31, 2009 and a PSCR Factor of 17.67 mills per kWh in residential customers' bills during that same period. The levelized PSCR Factors for which Applicant is seeking approval are based upon the Company's 2009 PSCR Plan. These Factors represent the amount by which the Company's projected fuel and purchased power expense, including transmission and MISO costs, are projected to exceed the Company's existing PSCR base of 17.32 mills per kWh during the 2009 PSCR Plan year, as well as amounts reflecting the 2005 PSCR Reconciliation Surcharge Credit and the projected 2008 PSCR Plan year under-collection.[1] These Factors will be applied to all PSCR customers consistent with the customer class distinctions explained supra. A Detroit Edison general rate case is also pending before the Commission (Case No. U-15244), which the Company anticipates will be completed in 2008 or 2009, so the PSCR base and PSCR Factors may be adjusted during the course of this proceeding. A discussion of the Company's PSCR Factors and base is provided in the testimony of Company witness Kenneth D. Johnston.

7. Nitrogen Oxide ("NO_x") and incremental Sulfur Dioxide ("SO_2") emission allowance expenses are also included in the Company's calculation of its 2009 PSCR Factors. NO_x and incremental SO_2 emission allowance expenses have been previously approved by the Commission for recovery through the PSCR process. (See Case No. U-13808 Order dated November 23, 2004, p 112; Case No. U-14702 Order dated September 26, 2006, p 5). Detroit Edison has determined that the best emission reduction strategy to comply with federal and state

[1] The PSCR base is that approved in the November 23, 2004 Order in MPSC Case No. U-13808.

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. Detroit Edison proposes to continue to address all SO_2 emission allowance cost variations above or below the amounts established in base rates through the annual PSCR process consistent with prior Commission orders and pending requests. Because a Detroit Edison general rate case is also pending before the Commission (Case No. U-15244), which the Company anticipates will be completed in 2008 or 2009, the movement of SO_2 emission allowance expense from non-fuel base rates to the PSCR base may occur during the course of this proceeding, changing the incremental nature of the SO_2 emission allowance expense.

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 2009 PSCR Plan proceeding. However, the Company has requested the continuation of the CIM in its pending rate case (Case No. U-15244) and therefore the CIM may be in effect and have impacts in (or in parallel with) Detroit Edison's 2009 PSCR Reconciliation proceedings.

9. Detroit Edison is purchasing from Heritage Sustainable Energy ("Heritage"), a company not affiliated with Detroit Edison, renewable energy credits ("RECs") for Detroit Edison's GreenCurrents renewable energy program (Detroit Edison Rider No. 15). A key element of the GreenCurrents renewable energy program is to encourage the development and operation of new renewable energy projects in Michigan. Heritage has developed the Stoney

Corners Wind Farm project ("Stoney Corners") in Michigan, and to help ensure that the project was developed, Detroit Edison entered into an 18-month power purchase agreement with Heritage for the capacity and energy from Stoney Corners**.** Company witness Wojtowicz, in her pre-filed direct testimony and in a separate line item shown on pre-filed Exhibit No. A-17 (APW-4) accompanying this application, sets forth the material terms of the arrangement. The project went on-line in September 2008. Detroit Edison respectfully requests, pursuant to MCL 460.6j(13), that the Commission deem the capacity charges associated with the power purchased from Stoney Corners to be pre-approved for recovery in Detroit Edison's PSCR Factors for 2009. Of course, Detroit Edison is also requesting that all energy costs be recovered through its 2009 PSCR Factors as well.

10. Applicant is also requesting Commission authority to include the costs of urea for recovery in the 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 Mr. Johnston, 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 therefore should be recovered in Detroit Edison's PSCR process. In fact, 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).

11. Finally, 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.

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

WHEREFORE, Applicant requests that this Commission:

A. Accept for filing this Application for authority to implement a PSCR Plan in its rate schedules for 2009 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. Grant Applicant’s requests, pursuant to MCL 460.6j(13)(b), that the Commission deem the capacity charges associated with the power purchased from Stoney Corners to be pre-approved for recovery in Detroit Edison’s PSCR Factors for 2009, along with the energy generated by Stoney Corners**.**

E. Approve Applicant’s request for recovery of the costs of urea in its PSCR process.

F. Enter its Order approving the implementation of Applicant's proposed PSCR Plan and Factors in Applicant's rates for 2009 metered jurisdictional sales of electricity, and otherwise expedite approval of Applicant’s request for levelized 2009 PSCR Factors of 17.29 mills per kWh in commercial and industrial customers' bills for the period January 1, 2009 through December 31, 2009 and 17.67 mills per kWh in residential customers’ bills during that same period.

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

H. Enter its Order approving, or otherwise making allowance for, adjustment of the 2009 PSCR base and Factors when the pending Detroit Edison general rate case (Case No. U-15244) is completed in 2008 or 2009.

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, 2008

By: Jon P. Christinidis

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Detroit, MI 48226
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STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

NOTICE OF HEARING
FOR THE ELECTRIC CUSTOMERS OF
THE DETROIT EDISON COMPANY
CASE NO. U-15677

- The Detroit Edison Company may implement a power supply cost recovery factor of 17.67 mills per kilowatt-hour (kWh) for residential customers and 17.29 mills per kilowatt-hour (kWh) for commercial and industrial customers, including amounts reflecting a 2005 PSCR Reconciliation Surcharge Credit for commercial and industrial customers and the projected 2008 PSCR Plan year under-collections for all customers in its retail electric customer bills for the 12-month period beginning January 1, 2009 through December 31, 2009, and may receive approval of recovery of urea costs, may receive pre-approval of capacity charges associated with certain power purchases, along with other regulatory approvals if the Michigan Public Service Commission approves its request.

- The information below describes how a person may participate in this case.

- You may call or write The Detroit Edison Company, 2000 Second Avenue, Detroit, Michigan 48226-1279, (313) 235-7706, for a free copy of its application. Any person may review the application at the offices of The Detroit Edison Company.

- The first public hearing in this matter will be held:

DATE:	October XX, 2008 This hearing will be a prehearing conference to set future hearing dates and decide other procedural matters.
TIME:	9:00 a.m.
PRESIDING OFFICER:	Administrative Law Judge Barbara A. Stump
LOCATION:	Michigan Public Service Commission 6545 Mercantile Way, Suite 7 Lansing, Michigan
PARTICIPATION:	Any interested person may attend and participate. The hearing site is accessible, including handicapped parking.

Persons needing any accommodation to participate should contact the Commission's Executive Secretary at (517) 241-6160 a week in advance to request mobility, visual, hearing or other assistance.

The Michigan Public Service Commission (Commission) will hold a public hearing to consider the September 30, 2008 2009 PSCR Plan Application of The Detroit Edison Company (Detroit Edison) which seeks approval of a power supply cost recovery (PSCR) plan for the 12 month period January 1, 2009 through December 31, 2009, a 5-year forecast of power supply, a PSCR factor of 17.67 mills per kWh on residential retail electric customers' bills in 2009, a PSCR factor of 17.29 mills per kWh on commercial and industrial retail electric customers' bills in 2009, including amounts reflecting a 2005 PSCR Reconciliation Surcharge Credit for commercial and industrial customers and the projected 2008 PSCR Plan year under-collections for all customers and seeks approval of urea as an integral part of PSCR expense, renews its request for pre-approval of capacity charges associated with certain power purchases, and seeks approval of other regulatory requests.

The Commission has selected this case for participation in its Paperless Electronic Filings Program. The Commission recognizes that filers may not have the computer equipment or access to the Internet necessary to submit documents electronically. Therefore, filers may submit an original and one paper copy to the: Executive Secretary, Michigan Public Service Commission, 6545 Mercantile Way, P.O. Box 30221, Lansing, Michigan 48909. Otherwise, no paper documents will be required to be filed in this case. Requirements and instructions for filing electronic documents can be found in the Electronic Filings Users Manual at: http://efile.mpsc.cis.state.mi.us/efile/usersmanual.pdf. The application for account and letter of assurance are located at http://efile.mpsc.cis.state.mi.us/efile/help. You may contact Commission staff at

517.241.6170 or by e-mail at mpscefilecases@michigan.gov with questions and to obtain access privileges prior to filing.

Any person wishing to intervene and become a party to the case shall electronically file a petition to intervene with this Commission by October XX, 2008. (Residential customers may file petitions to intervene using the traditional paper format.) The proof of service shall indicate service upon Detroit Edison's attorney, Jon P. Christinidis, 2000 Second Avenue, Detroit, MI 48226-1279.

Any person wishing to make a statement of position without becoming a party to the case may participate by filing an appearance. To file an appearance, the individual must attend the hearing and advise the presiding administrative law judge of his/her wish to make a statement of position.

A copy of Detroit Edison's request may be reviewed on the Commission's Web site at **http://efile.mpsc.cis.state.mi.us/efile** and at the office of The Detroit Edison Company, 2000 Second Avenue, Detroit, MI. For more information on how to participate in a case, you may contact the Commission at the above address or by telephone at (517) 241-6170.

A Utility Consumer Representative Fund has been created for the purpose of aiding the representation of residential utility customers in energy proceedings. Further information may be obtained from the Chairperson, Utility Consumer Participation Board, Department of Labor & Economic Growth, P.O. Box 30004, Lansing, Michigan 48909.

Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1982 PA 304, as amended, MCL 460.6j et seq.; 1969 PA 306, as amended, MCL 24.201 et seq.; and the Commission's Rules of Practice and Procedure, as amended, 1999 AC, R 460.17101 et seq.

THE DETROIT EDISON COMPANY HAS REQUESTED THE POWER SUPPLY COST RECOVERY FACTOR DESCRIBED IN THIS NOTICE. THE MICHIGAN PUBLIC SERVICE COMMISSION MAY APPROVE, REJECT OR AMEND THE FACTOR.

October XX, 2008
Lansing, Michigan

October XX, 2008

Case No. U-15677

Mr. Jon P. Christinidis
The Detroit Edison Company
2000 Second Avenue
Detroit, MI 48226-1279

Dear Mr. Christinidis:

The Detroit Edison Company shall mail, by October XX, 2008, a copy of the enclosed notice of hearing to all cities, incorporated villages, townships and counties in its electric service area, and to intervenors in Case No. U-15417, its 2008 PSCR plan case. Proof of service shall be filed by the prehearing conference on October XX, 2008.

The Detroit Edison Company shall cause the enclosed notice of hearing to be published, by October XX, 2008 in daily newspapers of general circulation in its electric service area. Publishing requirements and a copy of the publishing format are enclosed. Affidavits of publication shall be filed by the prehearing conference on October XX, 2008.

The Detroit Edison Company shall, by October XX, 2008, serve upon each person who has petitioned to intervene a copy of the written direct testimony of its proposed witnesses and the proposed exhibits as filed with the Commission. Proof of service shall be filed with the Commission by October XX, 2008**.**

Sincerely,

Mary Jo Kunkle
Executive Secretary

Enclosures

S T A T E O F M I C H I G A N

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 2009 Metered Jurisdictional Sales of Electricity	))))))	Case No. U-15677

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ROBERT A. GAILLIEZ

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF ROBERT A. GAILLIEZ

Line No.

Q. Please State your name and business address.

A. My name is Robert A. Gailliez and my business address is 2000 Second Avenue, Detroit, Michigan 48226.

Q. What is your present position with the Detroit Edison 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

Line No.

Nuclear Power Plant. I have been with The Detroit Edison Company (Detroit 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. What has been your involvement in rate case activities?

A. I sponsored testimony regarding the Company's nuclear fuel expense in the Company's 2008 PSCR Plan Case No. U-15417.

Line No.

Q. What is the purpose of your testimony?

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 No. A-1 (RAG-1)

Q. Which Exhibits are you supporting?

A. Exhibit No. A-1 (RAG-1) Year 2009 Power Supply Cost Recovery Plan
Exhibit No. A-2 (JDG-1) Fuel Expense Forecast–Nuclear Section only

Q. Were these Exhibits 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 (0.4 to 11 %).

Line No.

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 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.

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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 fuel must be designed and licensed to operate in a specific core. The fuel fabrication vendors are required to assure 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

Line No.

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-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

Line No.

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 that is planned for construction.

Q. Which areas within Detroit Edison have the responsibility for 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.

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

A. Detroit Edison has variable commitments which cover 100% of our uranium ore and conversion requirements through Cycle 20. The plant was refueled in October 2007 and we are currently in Cycle 13.

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

A. The original nuclear fuel contract with General Electric was negotiated in 1971,

Line No.

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 fabrication contract will continue as long as both parties agree to do so.

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 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 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.

Line No.

Regulatory costs are fees paid to governmental agencies relative to nuclear fuel. The current regulatory cost is the SNF disposal costs 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/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. Does the payment to the federal government for fuel disposal of $1.00/net MWh sold constitute all 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. 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

Line No.

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. Consequently, the current fee of $1.00/net MWh sold may not represent full measure for all expenses for disposal of SNF.

Q. Does Detroit Edison expect that the federal government may increase its fee collections for SNF storage or disposal programs?

A. In July of 2008, the U.S. Department of Energy's Office of Civilian Radioactive Waste Management released a report entitled "Fiscal Year 2007 Civilian Radioactive Waste Management Fee Adequacy Assessment Report." In that report, the U.S. Department of Energy finds that the current 1.0 mill per kilowatt-hour sold fee charged on generators of spent nuclear fuel is adequate for current needs. No recommendation is made for increasing the fee.

NUCLEAR FUEL EXPENSES

Q. What nuclear fuel expense is projected for the years 2009 through 2013?

A. Exhibit No. A-1 (RAG-1) provides the projection of Fermi 2 net electric generation and nuclear fuel expense for the specified years.

Line No.

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

A. Yes. Detroit Edison's Uranium supplier is anticipating moving to reduce its UF6 output slightly in 2010. In response, Detroit Edison made a UF6 spot purchase in 2007 to assist in covering a small projected UF6 shortfall. No immediate change in nuclear fuel costs resulted from this purchase. The use of this spot UF6 is factored into the projected fuel costs for 2010 and beyond when it will likely be used in the new fuel loaded into the Cycle 15 core. This small shortfall and spot purchase, in and of itself, will have only a small impact on fuel costs and was made to ensure continuity of UF6 supply.

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 actions are taken if it is discovered that a forecasted fuel cost is going to exceed budgeted costs?

A. 18 CFR 518 requires fuel amortization over the life of the fuel by heat generated. The fuel lifetime heat generation must be projected based on assumed plant operation. At the beginning of each operating cycle, the fuel cost budget is created based on a set of operating assumptions. If the

Line No.

operating assumptions differ from actual operation, then the fuel amortization plan can be adjusted to meet the regulatory intent for fuel amortization.

Q. Mr. Gailliez, can you explain nuclear fuel expenses as shown on Exhibit No. A-1 (RAG-1)?

A. These are fuel expenses directly tied to projected generation from Fermi 2. Exhibit No. A-1 (RAG-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 2013 are depicted on Exhibit No. A-1 (RAG-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 No. A-1 (RAG-1). The generation targets are used to determine the expected energy requirement for the fuel cycle.

Line No.

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 approximately three-quarters of the noted fuel expenses. The remaining portion of fuel expense includes disposal fees paid to the DOE pursuant to Title 10, Part 961, Appendix G of the Code of Federal Regulations. Exhibit No. A-1 (RAG-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. Mr. Gailliez, what are your thoughts 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 spot market. Fermi ore and enrichment services prices have been below the spot market for many cycles and based on our fuel contracts, the trend should continue. The projected unit prices for ore and enrichment services assume the price will be less than the spot market price. Fabrication pricing does not have an equivalent benchmark. Fermi controls fabrication costs with engineering time which maintains reload batch sizes small. Thus the number of fuel bundles remains optimum which lowers fabrication costs and reduces the required amount of ore and enrichment services. Future prices are reflected in Exhibit No. A-1 (RAG-1) and the total unit price is expected to remain below the sum of the component spot

Line No.

market prices, all of which have experienced significant increases.[1] 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.

Q. Mr. Gailliez, what is the basis for your belief that projected fuel costs for Fermi 2 are reasonable?

A. A number of concerted efforts contributed to this assessment. First, contracts associated with fuel assembly fabrication as well as contracts to supply uranium ore and provide enrichment services were re-negotiated. Prior to 1999, contractual agreements precluded Detroit Edison the ability to re-negotiate these services. Consequently, when the opportunity became available to negotiate more favorable pricing, Detroit Edison acted in an appropriate and timely fashion. I would like to stress that a majority of the fuel cost reduction was made possible by the initiative of the Fermi 2 staff to actively pursue and obtain more favorable fuel pricing. Also contributing to this reduction in fuel expenses as reported by Fermi 2, was the termination of a contractual agreement with Renaissance Energy Company. Renaissance provided leasing services associated with the nuclear fuel. In 2001, the remaining principal on the lease with Renaissance was paid. Improved core design by the Fermi 2 staff working with the fuel fabrication vendor has

[1] For example, the publicly available market price for uranium ore of $64.50 in September 2008 represents a market price increase of more than 550% since September 2002. Similarly, the price for conversion services has more than doubled over that same period.

Line No.

resulted in fewer fuel bundles required during core reloads. Lastly, the Fermi 2 Staff has maintained reasonable nuclear fuel expenses even during recent price increases. Again, 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 conclude your direct testimony?

A. Yes.

S T A T E O F M I C H I G A N

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 2009 Metered Jurisdictional Sales of Electricity	))))))	Case No. U-15677

EXHIBIT

OF

ROBERT A. GAILLIEZ

Case No.: U-15677
Exhibit No.: A-1 (RAG-1)
Witness: R. A. Gailliez
Page No.: 1 of 1

Year 2009 Power Supply Cost Recovery Plan

DETROIT EDISON PROJECTED NUCLEAR FUEL EXPENSE 2009 – 2013

($ 000)

(A) Year	(B) GWHr	(C) Fuel Amort	(D) In-core Interest	(E) Regulatory Cost	(F) Nuclear Fuel Exp	(G) $/MWHr	(H) Cents/ MBTU
2009	8,843	33,985	0	8,136	42,121	4.76	46.3
2010	8,838	39,054	0	8,131	47,185	5.34	51.9
2011	9,675	52,200	0	8,901	61,101	6.32	61.4
2012	8,867	53,064	0	8,158	61,222	6.90	67.1
2013	9,154	57,125	0	8,422	65,547	7.16	69.7

S T A T E O F M I C H I G A N

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 2009 Metered Jurisdictional Sales of Electricity	))))))	Case No. U-15677

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

JAMES D. GOOD

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF JAMES D. GOOD

Q. Please state your name and position.

A. My name is James D. Good. My position is that of Supervisor, Business Development and Administration, Fuel Supply.

Q. What is your business address?

A. My business address is 2000 Second Avenue, Detroit, Michigan 48226.

Q. Please state your educational background.

A. My formal education consists of a Bachelor of Chemical Engineering degree from the University of Detroit in 1978. I have also completed several Company sponsored courses and have attended various conferences and seminars to further my professional development.

Q. Please summarize your professional experience.

A. In 1978 I joined Detroit Edison and was assigned to the Chemical Engineering group in the Engineering Research Organization as an assistant engineer at the Conners Creek Power Plant. In this position I was responsible for providing technical support to the Plant in the areas of water treatment and wastewater treatment. My responsibilities included the check-out and initial operation of the various wastewater treatment systems, as well as supporting the Plant in the operation and maintenance of boiler water, feedwater, and make-up water treatment systems.

In 1980, I was assigned to the River Rouge Power Plant where again I was responsible for providing technical support to the Plant in the areas of water treatment and wastewater treatment.

In 1987, I transferred to the Air Quality and Biology group in the Engineering Research Organization as a senior engineer. In this position I was responsible for power plant stack emission testing, as well as projects relating to air pollution control equipment.

Later in 1987, I transferred to the Chemical Engineering group in the Engineering Research Organization. My responsibilities included providing support for the chemical engineering functions for all of the Detroit Edison power plants, along with conducting various research projects related to water treatment in the power plants.

In 1989, I was reassigned to the River Rouge Power Plant with the responsibility of providing technical support to the Plant in water and wastewater treatment.

In 1993, I was reassigned to the Trenton Channel Power Plant with the responsibility of providing technical support in the areas of water and wastewater treatment.

In 1996, I was reassigned to the Lubrication group in the Technical Engineering Services Organization (which had absorbed the Engineering Research Organization). My responsibilities included providing support to the various Detroit Edison power plants for lubrication related issues.

In 2000, I was promoted to the position of lubrication engineer in the Technical Engineering Services Organization. In this position, I was responsible for directing the lubrication programs at the various Detroit Edison power plants and for directing the laboratory personnel at the Warren Service Center Lubrication Laboratory.

In 2001, I transferred to the Fuel Supply Organization as Supervisor – Fuel Quality in the Operations and Logistics group. My responsibilities included managing the personnel responsible for obtaining and recording the quality data on all of the Detroit Edison coal shipments, tracking the performance of the coal suppliers in relation to the contractual quality obligations, managing the chemical treatment of the coal and coal trains in the winter to minimize frozen coal problems, and for conducting periodic surveys of the Detroit Edison coal piles for the purpose of adjusting the physical inventory records to actual. In addition, I was responsible for providing technical support to the Detroit Edison power plants in the area of fuel quality.

Line No.

In 2007, I was assigned to the position of Supervisor – Fuel Resources in the Business Development and Administration group within the Fuel Supply Organization. In this position, my responsibilities include assisting in the generation of short and long-term fuel plans, the analysis of fuel budget variances and monitoring progress toward meeting the organization's key performance drivers.

Q. To what extent have you participated in rate cases and other proceedings before regulatory commissions?

A. I have provided support for the fossil fuel expense witness in Power Supply Cost Recovery Case No. U-15417. I was the fossil fuel expense witness in the Detroit Edison Company's 2007 PSCR Reconciliation Case No. U-15002-R.

Line No.

Q. Mr. Good, what is the purpose of your testimony in this case?

A. The purpose of my testimony is to support the fossil fuel expense shown in Exhibit No. A-2 (JDG-1).

Q. Please describe Exhibit No. A-2 (JDG-1).

A. Exhibit No. A-2 (JDG-1) is the five-year forecast (2009 through 2013) 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 2009?

A. The 8 month actual, 4 month forecast "8&4 Outlook" for 2008 is the basis for the 2009 forecast. The 8&4 Outlook uses actual September 1, 2008 inventory quantities and costs and forecasts the remaining four months of 2008. The forecasted December 31, 2008 inventory quantities and costs are inputs to the 2009 forecast.

The forecasted delivered coal costs for the last four months in 2008 and for 2009 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 were based upon information obtained

from market sources such as forward prices obtained from an over-the-counter (OTC) coal broker. 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) model for the balance of 2008 and 2009. The FPE applies existing and forecasted coal prices and transportation rates to the monthly delivery requirements. 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 Ms. Wojtowicz. Delivery requirements for oil and gas are determined in a similar manner. The FPE output and delivered oil and gas delivery requirements and costs are used as inputs to Corporate Accounting's Forecasting Information and Budgeting System (FIBS) model. Fossil fuel expense was calculated in FIBS by multiplying the average cost of inventory by fuel consumed.

Q. What was the method used to develop the forecast for years 2010 and

Line No.

beyond?

A. Existing and forecasted coal prices and transportation rates were applied to the monthly delivery requirements in individual FPE model runs for 2010-2013, similar to the methodology used for 2009. 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 percentage change from the 2009 to the 2010 plant unit cost of coal delivered was applied to the 2009 plant unit cost of coal expense determined in FIBS to forecast the 2010 plant unit cost of coal expense. Similarly, the percentage change from the 2009 to the 2011 Detroit Edison generation plant unit cost of coal delivered was applied to the 2009 plant unit cost of coal expense to forecast the 2011 plant unit cost of coal expense. The same methodology was used to forecast the 2012 and 2013 plant unit cost of coal expense. Each year's unit cost of coal expense so determined was applied to the coal consumption requirements calculated in PROMOD to develop the coal expense forecast.

The forecasted spot market coal prices for 2010 and 2011 were determined in the same manner as the 2009 forecast. In 2012 and 2013 western and eastern coal prices were estimated to remain constant with 2011, with the exception of changes in the value of the coal due to the variability of the SO_2 emissions cost/ton SO_2.

The forecasted delivered gas and oil costs for 2010-2013 were determined in

Line No.

the same manner as the 2009 forecast. The delivered oil and gas costs were applied to the oil and gas consumption requirements calculated in PROMOD to develop the oil and gas expense forecast.

Q. What is your opinion regarding this method of forecasting?

A. When preparing long-term fuel forecasts, it is reasonable to assume delivery requirements equal consumption. Only minor differences in total annual fuel expense would be expected if monthly inventory changes were considered. This method of forecasting is reasonable, prudent and consistent with the methodology used in previous PCSR plan cases.

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

Line No.

2009, the F.O.B. mine price (¢/MBtu), the term of the contract and the type of coal.

Supplier	Tonnage	¢/Mbtu	Term	Coal Type
#1	1,500,000	82	1/09-12/10	LSW
#2	4,500,000	66	1/07-12/10	LSW
#3	1,000,000	82	1/09-12/10	LSW
#4	522,000	71	1/09-12/10	LSW
#5	2,000,000	61	7/04-12/09	LSW
#6	500,000	108	1/09-12/10	LSW
#7	478,500	88	8/08-12/09	LSW
#8	1,000,000	105	8/08-12/09	LSW
#9	100,000	224	7/08-11/09	LSS
#10	750,000	193	1/08-12/10	MSE
#11	1,368,000	196	1/07-12/09	MSE
#12	750,000	191	1/07-12/09	MSE
#13	500,000	210	1/08-12/09	MSE
#14	100,000	312	1/09-12/11	MSE
#15	468,000	184	6/07-12/09	MSE
#16	351,000	178	8/07-12/09	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 one year in duration.

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 through both MPSC approved tariffs with the local distribution companies (LDC) and spot market purchases.

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 PSCR plan and five-year forecast include projections for the continued use of coke oven gas at Detroit Edison's River Rouge Power Plant. Coke oven gas is supplied by an affiliated company of Detroit Edison under an agreement that began in June, 2006. Coke oven gas consumption displaces 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. What are some of the major assumptions supporting the coal forecast presented on Exhibit No. A-2 (JDG-1)?

A. The long-term forecast of coal prices assumes the Company's continued reliance on low sulfur western (LSW) coal. For 2009, over 70% 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

Line No.

from Central and Northern Appalachia. Coals from this region include low sulfur eastern (LSS), mid sulfur eastern (MSE) and high sulfur eastern (HSE).

Q. What is your opinion as to how the increasing coal and oil prices have affected Detroit Edison's overall fossil fuel expense?

A. The market prices for coal and oil have increased considerably in the last year (>50%). This has affected Detroit Edison's fossil fuel expense in 3 ways. First, the FOB mine spot price of Eastern coal purchased under new contracts will be significantly higher than in previous years' contracts. Second, the transportation rates for both rail and vessel shipments of coal have increased due to supplier pass-through of their increased fuel costs. Third, the cost of oil purchased has increased over previous years.

Detroit Edison has mitigated these costs by continuing to rely on LSW coal, which has not seen the large increases in FOB mine price. As previously described, LSW coal is projected to be over 70% of the coal consumed. In addition, about 65% of the eastern coal needed in 2009 was procured at below current market rates. As these contracts expire, it is projected that Detroit Edison's fossil fuel expense will increase due to the higher priced eastern coal contracts. Detroit Edison will continue to work with available coal suppliers to obtain coal under long term contracts at a favorable rate compared to the current projected spot price.

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

A. I believe that we have developed a fuel supply plan that meets Detroit Edison's requirements, is consistent with both the Company's policies and objectives, provides for the delivery of electric generation to customers at a reasonable price 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 moves in private equipment.

The Company continues to aggressively market coal and transshipment services to third parties through its subsidiary, MERC. Third party revenues

Line No.

and the equity received from MERC's joint venture contribute to a significant reduction in Detroit Edison fuel expense and thus, ultimately, the electric rates for Detroit Edison electric customers.

The Company is also determined to pursue all reasonable avenues to resolve disputes with its suppliers, including negotiation, arbitration and litigation, if 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 and I recommend that the Commission so find.

Q. Does this conclude your testimony?

A. Yes.

S T A T E O F M I C H I G A N

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 2009 Metered Jurisdictional Sales of Electricity	))))))	Case No. U-15677

EXHIBIT

OF

JAMES D. GOOD

The Detroit Edison Company
Fuel Expense Forecast
Years 2009 - 2013

Case No. U-15677
Exhibit No. A-2 (JDG-1)
Page 1 of 1
Witness: J. D. Good/R. A. Gailliez

	(a)	(b)	(c)	(d)	(e)	(f)
		2009	2010	2011	2012	2013
1	Coal**					
2	MBtu (000)	410,588	413,969	413,687	390,812	394,560
3	¢/MBtu	219.2	272.3	341.9	340.1	343.1
4	$ (000)	900,075	1,127,182	1,414,291	1,329,333	1,353,836
5						
6	No.2 Oil*					
7	MBtu (000)	521	507	519	474	474
8	¢/MBtu	2,573.2	2,543.0	2,471.4	2,395.5	2,395.8
9	$ (000)	13,403	12,905	12,827	11,364	11,348
10						
11	No.6 Oil					
12	MBtu (000)	846	867	796	689	549
13	¢/MBtu	1191.0	1825.0	1770.1	1709.9	1709.1
14	$ (000)	10,072	15,831	14,092	11,780	9,375
15						
16	Natural Gas**					
17	MBtu (000)	4,088	3,857	3,650	3,157	2,618
18	¢/MBtu	893.1	1024.0	987.9	976.1	970.1
19	$ (000)	36,507	39,491	36,059	30,815	25,398
20						
21	Coke Oven Gas					
22	MBtu (000)	721	730	605	694	681
23	¢/MBtu	255	264	283	283	284
24	$ (000)	1,839	1,926	1,712	1,966	1,935
25						
26	Total Fossil					
27	MBtu (000)	416,763	419,931	419,257	395,826	398,881
28	¢/MBtu	230.8	285.1	352.8	350.0	351.5
29	$ (000)	961,896	1,197,336	1,478,980	1,385,258	1,401,892
30						
31	Nuclear Fuel					
32	MBtu (000)	90,964	90,915	99,518	91,211	93,986
33	¢/MBtu	46.3	51.9	61.4	67.1	69.7
34	$ (000)	42,121	47,185	61,101	61,222	65,547
35						
36	All Fuels					
37	MBtu (000)	507,727	519,449	513,243	395,826	398,881
38	¢/MBtu	197.7	242.3	300.9	350.0	351.5
39	$ (000)	1,004,017	1,258,437	1,544,527	1,385,258	1,401,892
40						
41	* Excludes MPPA's portion of Belle River					
42	** Includes Industrial Steam					

S T A T E O F M I C H I G A N

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 2009 Metered Jurisdictional Sales of Electricity	))))))	Case No. U-15677

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

KENNETH D. JOHNSTON

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF KENNETH D. JOHNSTON

Line No.

Q. Please state your name and business address.

A. My name is Kenneth D. Johnston. My business address is The Detroit Edison Company, 2000 Second Avenue, Detroit, Michigan 48226.

Q. What is your present position?

A. I am a Regulatory Consultant in Regulatory Affairs.

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 on Retail Open Access offered by the Michigan Electric Power Coordination Center, attended the Lighting

Line No.

Upgrade Workshop offered by the US Environmental Protection Agency, and completed the Nuclear Utility Procurement Training sponsored by 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 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 The Detroit Edison Company (Detroit Edison or 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 scheduling engineer at the Fermi 2 Nuclear Power Plant. In this capacity I developed, programmed, and directed the production of plant outage

Line No.

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.

I was promoted to materials engineer, Nuclear Materials Management, in January of 1990. In this capacity, I performed independent engineering evaluations of mechanical and electrical equipment and parts.

In March 1991, I was promoted to senior materials engineer, Nuclear Materials Management and had the lead responsibility for the parts planning, receipt inspection, and material testing for the entire plant. In this capacity I provided work direction to five engineers and technicians and represented Detroit Edison as a member of the EPRI Obsolete Items Database Technical Working Group and the General Electric Boiling Water Reactor Pooled Inventory Management Equipment Committees.

I was promoted to principal (lead) engineer in March 1993 and was responsible for the work direction of 13 engineers and technicians in the performance of material engineering, parts planning, and receipt inspection activities. I continued to represent the Company as a member of the EPRI Obsolete Items

Line No.

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, performed troubleshooting and root cause analysis of equipment failures, including identification of corrective action to prevent failure recurrence, and prepared engineering design documents for the use of alternate replacement equipment. In addition, I prepared component operability evaluations for degraded equipment and performed technical reviews of procedures and field work packages.

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.

Line No.

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. I managed and supported the development and implementation of, and/or enhancements to, various program features including customer enrollment, customer billing, electronic business transactions (conversion from EDI to XML), creation and provision of billing determinants, and data presentment.

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). Subject matter includes Electric Choice (implementation cost recovery, rates, tariff administration, transition charges, energy efficiency, code of conduct, market priced power, and program participation), transmission & ancillary services (rates, billing, energy scheduling, energy imbalance service), rates for industrial send-out steam, and wholesale-for-resale rates. I prepare monthly fuel adjustment factors for industrial steam rates and wholesale for resale rates,

Line No.

prepare the Power Supply Cost Recovery (PSCR) 45-day report, and have prepared 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 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

Line No.		
1	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
4	U-15223	In the matter of the complaint of Commerce Energy Inc. against The Detroit Edison Company

6 I was the case manager and sponsored testimony in the following cases:

7	U-14025	In the matter of the complaint of Strategic Energy LLC against The Detroit Edison Company
9	U-14054	In the matter of the complaint of Quest Energy against The Detroit Edison Company
11	U-14070	In the matter of the complaint of Constellation NewEnergy, Inc. against The Detroit Edison Company.
13	U-14275	2005 Power Supply Cost Recovery Plan
14	U-14275-R	2005 Power Supply Cost Recovery Reconciliation
15	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.
18	U-14817	2005 Pension Equalization Mechanism Reconciliation
19	U-14702	2006 Power Supply Cost Recovery Plan

Line No.		
1	U-14702-R	2006 Power Supply Cost Recovery Reconciliation
2	U-15259	2006 Pension Equalization Mechanism Reconciliation
3	U-15002	2007 Power Supply Cost Recovery Plan
4	U-15081	In the matter of the complaint of FirstEnergy Solutions Corp. against The Detroit Edison Company for violation of the Code of Conduct
7	U-15417	2008 Power Supply Cost Recovery Plan

In addition, I was the case manager and also submitted several affidavits regarding energy imbalance service and the recalculation of energy imbalance service costs in FERC Docket EL04-31-000, and was the case manager in FERC Docket EL04-119-000.

Line No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the calculation of the PSCR billing factors to be utilized for each month of 2009. I have also calculated projected average annual PSCR billing factors for the years 2010 through 2013.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring exhibits which show the calculation of PSCR billing factors. The 2009 PSCR factor for residential customers is 17.67 mills/kilowatt-hour and the 2009 PSCR factor for commercial and industrial customers (C&I) is 17.29 mills/kilowatt-hour. These are levelized monthly billing factors. They are developed on Exhibit No. A-3 (KDJ-1). PSCR billing factors for the years 2010 through 2013 appear on Exhibit No. A-4 (KDJ-2).

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 17.32 mills per kWh. The average unit cost is determined on a net system requirement basis, exclusive of the MWh and dollars associated with R-10 and similar interruptible loads. This methodology is consistent with prior years' calculations, prior Commission orders including

Line No.

the November 23, 2004 Order in MPSC Case No. U-13808, and Section C8.1 of the Detroit Edison Company Rate Book for Electric Service.

Q. Is the Company requesting approval of any new cost elements in the 2009 PSCR Plan?

A. Yes. The Company is requesting that the Commission recognize the cost of urea as an integral part of the cost of power supply and includible in PSCR expenses. A more detailed discussion of urea is presented in the testimony of Edison witness Ms. Angela Wojtowicz.

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

A. As explained in greater detail 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.

Q. Has the Commission previously approved the recovery of chemicals

used to reduce emissions as power supply costs in the PSCR?

A. Yes. The Commission has approved a rate case settlement agreement[1] that included a provision that permitted the utility to recover chemical additives that assist in reducing the utility's emissions at its generating plants.

Q. Is the accounting afforded urea determinative of its rate treatment?

A. No, not necessarily. While accounting and ratemaking can be congruous this does not mean that an element of cost cannot be recovered through the PSCR clause purely because of the account in which it is booked. In its June 30, 2005 Opinion and Order in Case No. U-14274, Consumers Energy Company's 2005 PSCR Plan, the Commission stated "Nowhere in MCL 460.6j(a) and (b) is there any reference to the USOA or any indication that recovery of such costs is entirely dependent upon the account into which the costs are booked." (June 30, 2005 Order in MPSC Case No. U-14274 at p. 6)

The Commission has properly focused on the nature of the expense for ratemaking purposes on prior occasions. Most recently, in Detroit Edison's 2006 PSCR Plan Case No. U-14702, the Commission approved the inclusion of SO_2 emission allowance expense in its September 26, 2006 Order stating:

> "The Commission agrees with the ALJ and the Staff. The use of SO2 allowances is part of the decision-making required in determining what blend of coals to use, and how much power to purchase. SO2 allowances are volatile in much the same way that fuel is volatile, because the price of the two is inextricably linked. The Attorney General argues that SO2 allowance costs are not booked costs for

[1] Opinion and Order, Case No. U-15352, December 4, 2007, Exhibit A, Settlement Agreement, Paragraph 8.g., page 3.

> fuel burned. However, SO2 allowance costs are linked to the availability of generation, and their volatile nature makes them more appropriate for PSCR plan and reconciliation consideration than for rate case consideration. The Commission notes that its previous determination finding emissions fees to be appropriate for PSCR treatment applied to fees for oxides of nitrogen (NOx), particulates, volatile organic compounds, and SO2." (September 26, 2006 Order in MPSC Case No. U-14702, p. 5)

Clearly, urea is a cost of fuel burned for electric generation. As described in more detail by Ms. Wojtowicz, urea is an integral part of prudent fuel procurement and utilization. Consequently, the Company is requesting Commission approval for this change in ratemaking expense treatment in the PSCR.

Q. Has the Company included any adjustments to its projected expense in the 2009 PSCR Plan?

A. Yes. The Company has reduced its projected 2009 SO_2 emission allowance expense by $0.716 million (see Exhibit No. A-20 (APW-7). The Commission approved the recovery of SO_2 emission allowance expense in the PSCR its September 26, 2006 Order in the Company's 2006 PSCR Plan Case No. U-14702. However, the Commission had previously included a total of $0.716 million of SO_2 emission allowance expense in the Company's non-fuel base rates in the November 23, 2004 Order in MPSC Case No. U-13808. Therefore, the Company's 2009 PSCR expense only reflects the SO_2 emission allowance expense in excess of $0.716 million. This net credit is based upon a

Line No.

projected SO_2 emission allowance expense of $1.45 million[2] and a revenue credit of $733,742[3] from the proceeds of the Environmental Protection Agency ("EPA") auction of SO_2 emission allowances, each of which were reflected in the November 23, 2004 Order in MPSC Case No. U-13808. This adjustment effectively reduces the Company's 2009 projected SO_2 emission allowance expense from $3.29 million to $2.57 million.

Q. Has the Company included any provision for an over/(under) recovery from the 2008 PSCR period included in the 2009 PSCR Plan?

A. Yes. At the time of this filing, Detroit Edison projects that it will incur a PSCR under-recovery of $68.7 million for all customers subject to the PSCR for the 12 month period January 2008 through December 2008. Although the Company has not received a final order in its 2007 PSCR Reconciliation Case No. U-15002-R, it has based its 2008 PSCR under-recovery position on a January 1, 2008 PSCR beginning under-recovery balance of $43.626 million supported in that filing. The Commission granted the Company continuing authority to roll prior year under and over-recoveries into its future powersupply cost recovery plans in its December 21, 2006 Order Approving Temporary Factors in the Company's 2007 PSCR Plan Case No. U-15002.

[2] Case No. U-13808, Exhibit A-16, Schedule F8-8, Line 24, Column (d) and Exhibit S-123 Revised, Line 4, per the November 23, 2004 Order in MPSC Case No. U-13808, p. 112.

[3] Case No. U-13808, Exhibit A-3, Schedule C-1, line 2, Column (d) and 2002 MPSC Form P-521, Pg. 115, Col (e), Line 21, included Gains from Disposition of Allowances (EPA auction proceeds) which were not adjusted in the determination of the Company's revenue deficiency.

Line No.

Q. Has the Company included any other provisions for an over/(under) recovery from prior PSCR periods in the 2009 PSCR Plan?

A. Yes. At the time of this filing, Detroit Edison projects that it will incur a PSCR over-recovery of $12.2 million for the 2005 PSCR Reconciliation surcharge which was applicable to C&I customers only. This 12-month reconciliation surcharge was implemented beginning in June of 2007 in accordance with the Commission's May 22, 2007 order in MPSC Case No. U-14275-R. This overcollection amount will be returned to C&I customers only, resulting in the one-time need for two different PSCR factors in 2009.

Q. Has the Company included any other adjustments in the Company's 2009 PSCR plan?

A. Yes. As detailed in the testimony of witness Siefman, the Company has included adjustments to its service area sales to reflect the implementation of an energy optimization plan. Legislation that is expected to become law in 2008 will drive incremental sales reduction targets for Detroit Edison of 0.3% of 2007 sales in 2008-2009, 0.5% of 2009 sales in 2010, 0.75% of 2010 sales in 2011, 1.0% of 2011 sales in 2012 and 1.0% of 2012 sales in 2013.

Q. Edison Witness Ms. Wojtowicz reflects power purchases under a renewable energy portfolio standard, can you explain these projections?

A. Yes. In addition to energy optimization, the legislation also creates a renewable energy portfolio standard which drives the Company to attain a

Line No.

renewable energy portfolio of 10% by 2015, and includes interim targets for 2012, 2013 and 2014. Ms. Wojtowicz's purchased power reflects renewable energy utilization directed towards attainment of those goals.

Q. Has the Company entered into any specific purchase power agreements or started construction on any renewable energy projects towards attainment of the interim renewable energy portfolio goals?

A. No. These renewable energy purchases are simply a placeholder at this point in time. The Company expects to file renewable energy plans pursuant to the legislation that will contain more detailed discussions regarding attainment of the renewable portfolio standard and specific renewable energy generation projects and renewable energy credit purchases.[4]

Q. Can you explain how the pricing was developed for the renewable energy reflected in Ms. Wojtowicz's purchased power portfolio?

A. Yes. The legislation requires the Commission to annually establish a price per megawatt hour at which price the energy will be furnished to retail customers through the PSCR mechanism. The legislation provides for consideration of projected capacity, energy, maintenance, and operating costs in determiningThis price. At this juncture, the Company's has forecast a price that is based upon a combination of forward market and capacity prices.

[4] As described by Edison witness Ms. Wojtowicz, the Company has previously entered into a 18-month agreement with Heritage Sustainable Energy, the energy from which may support attainment of the interim renewable energy targets contained in legislation.

Line No.

Ultimately, the Commission will set the price at which the energy will be provided to retail customers through the PSCR.

Q. What factors would the Company self-implement on January 1, 2009?

A. The Company intends to self-implement a maximum PSCR billing factor of 17.54 mills/kWh on January 1, 2009 for residential customers and a maximum PSCR billing factor of 17.16 mills/kWh on January 1, 2009 for C&I customers.[5] These PSCR factors represent the Company's projected 2009 PSCR costs excluding the projected urea expense in accordance with MCL 460.6j(13)(a), which requires the Commission to disallow cost increases resulting from changes in accounting or rate-making expense treatment. The Company will increase this maximum factor should it receive Commission approval to do so. In addition, should the Commission rule on the Company's 2007 PSCR Reconciliation Case No. U-15002-R prior to that time, the Company will adjust its maximum PSCR billing factors accordingly.

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

A. No. The Company has not included any contingency adjustments to power supply expense as was proposed in its 2006 PSCR Plan. The Company's

[5] The Company's proposed maximum PSCR factors to be self-implemented on January 1, 2009 do not reflect the expense associated with urea.

power supply expense has been determined in accordance with an Electric Choice sales forecast level of 1,366 GWh as discussed in the testimony of Edison witness Sherrie 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 2009 PSCR Plan year as late as December 1, 2008, 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, 2008, which can result in unexpected increases in PSCR expense.

Q. What happens if an existing Electric Choice customer doesn't provide return to service notification by December 1, 2008 but ultimately returns to full requirements service in 2009?

Line No.

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 2009 without providing proper notification will be subject to Market Priced Power (MPP) charges. These charges are designed to offset the incremental cost of serving those customers and will effectively maintain the previously projected average PSCR expense.

During the PSCR plan years of 2006 through 2008, the Company has imposed total MPP charges of more than $6.5 million in the bills of customers that have failed to meet the return to service notification deadlines, meet the minimum stay requirements on Electric Choice service or 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 2009 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 2009 PSCR Plan year. In addition, the MPP charges imposed on customers that didn't provide proper notice, meet the minimum stay on Electric Choice or commit to the minimum stay on Detroit Edison full electric service will serve 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

Line No.

incurs due to their actions.

Q. Can you describe the development of the PSCR Factors on Exhibit No. A-10 (KDJ-1) and Exhibit No. A-11 (KDJ-2)?

A. Yes. The Power Supply Costs (adjusted for R-10, other interruptible sales, and third party wholesale sales) shown on Line 1 were obtained from Edison Witness Ms. Angela P. Wojtowicz's Exhibit No. A-14 (APW-1), page 1 of 1, Line 43. 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 Ms. Angela P. Wojtowicz's Exhibit No. A-14 (APW-1), page 1 of 1, Line 42. This Net System Requirement value reflects an Electric Choice forecast for 2008 of 1,366 GWh based upon Edison witness Sherrie Siefman's Exhibit No. A-12 (SLS-5).

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

Line No.

are those approved by the Commission in the November 23, 2004 Order in MPSC Case No. U-13808.

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 17.67 mills/kWh is the product of the Unit Cost Above (Below) Base and the Loss Multiplier shown on Line 8 and will be used for residential customers during 2009.

The 2005 PSCR Reconciliation Credit (C&I) shown on Line 10 is the Company's current projection of its recovery of its 2005 PSCR Reconciliation surcharge which was applicable to C&I customers only. [6]

The 2009 C&I PSCR Sales shown on Line 11 is the Company's forecasted sales for its metered commercial and industrial sales subject to the PSCR clause.

[6] The Commission issued an order in the Company's 2005 PSCR Reconciliation Case No. U-14275-R on May 22, 2007 allowing the Company to surcharge commercial and industrial customers for a 12-month period beginning June 2007.

The PSCR Factor shown on Line 12 of 17.29 mills/kWh is the product of the Unit Cost Above (Below) Base and the Loss Multiplier shown on Line 8 and will be used for commercial and industrial customers during 2009.

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%.

Line No.

Q. Do you have any clarifications to make with respect to the Base Unit Cost, the Loss Multiplier, and the PSCR Factor that are presented?

A. Yes. In the Company's current general electric rate Case No. U-15244, the Company has requested a new base unit cost and loss multiplier.[7] To the extent that the Company receives a final order in MPSC Case No. U-15244 which sets a different base unit cost and/or loss multiplier from the existing 17.32 mills/kWh and 7.2%, Detroit Edison will adjust the PSCR factor to be consistent with the final order in that proceeding.

Q. Are there any other changes that could take place as a result of the issuance of a final order in the Company's general electric rate case No. U-15244?

A. Yes. The Company's requested PSCR base of 31.26 mills/kWh reflects SO_2 emission allowance expense of $13.682 million[8] versus the $0.716 million amount currently reflected in base rates. If a final order in MPSC Case No. U-15244 moves SO_2 emission allowance expense out of non-fuel base rates into the PSCR base, the credit currently being provided for the non-fuel base rate amount would no longer be applicable.

[7] The Company has requested a new PSCR base of 31.26 mills/kWh and loss factor of 6.8%. (MPSC Case No. U-15244, Updated Direct Testimony of Timothy A. Bloch, pages 12-13 and Exhibit No. AU-13, Schedule E6-1 page 1 of 1).

[8] MPSC Case No. U-15244, Exhibit No. A-16 Schedule F11.

Line No.

Also, as discussed more fully by Edison witness Mr. Shields, the Company has proposed in MPSC Case No. U-15244 that the revenues and expenses associated with ancillary service tariff schedules 2, 3, 5 & 6 be reconciled within the PSCR mechanism in anticipation of the start of the MISO ancillary services market. Currently, a portion (Schedule 2) or all (Schedules 3, 5, & 6) of the revenues and expenses from these ancillary service tariff schedules are reflected in base rates. If a final order in MPSC Case No. U-15244 moves ancillary service tariff revenues out of non-fuel base rates into the PSCR base, all of the net revenues from the provision of ancillary services would be reconciled within the PSCR.

Q. How will the Company ultimately reconcile the amounts collected to recover the projected 2008 PSCR underrecovery?

A. Detroit Edison will reconcile the amounts collected with the actual under-recovery amount within the applicable annual PSCR Reconciliation filing. For instance, if Detroit Edison applied a positive surcharge to its PSCR customers' bills for its projected 2008 PSCR under-collection during 2009, Detroit Edison would reconcile the actual amounts collected during 2009 with the actual 2008 reconciliation amount ordered in the 2008 PSCR reconciliation in its 2009 PSCR Reconciliation proceeding. The Company would amortize the 2008 PSCR under-collection amount throughout 2009, 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

Line No.

reasonably and prudently incurred in its 2008 PSCR Reconciliation proceeding.

Q. Does this complete your testimony?

A. Yes, it does.

S T A T E O F M I C H I G A N

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 2009 Metered Jurisdictional Sales of Electricity	))))))	Case No. U-15677

EXHIBITS

OF

KENNETH D. JOHNSTON

Case No.	**U-15677**
Exhibit No.	**A-3 (KDJ-1)**
Witness	**K. D. Johnston**
Page No.	**1 of 1**

Detroit Edison Company
Power Supply Cost Recovery Factor
Forecast Period January 2009 through December 2009

Line No.		(a) 2009	
1	2009 Power Supply Costs (adjusted for R10, other interruptible & third party sales)	$1,659,972	
2	Projected Prior Year PSCR (over)/undercollection	$68,737	
3	Total Power Supply Costs	$1,728,709	
4	Net System Requirement (adjusted for R10, other interruptible & third party sales)	51,143	GWh
5	Unit Cost of Power Supply	33.80	Mills/kWh
6	Base Unit Cost	17.32	Mills/kWh
7	Unit Cost Above (Below) Base	16.48	Mills/kWh
8	Loss Multiplier	1.072	
9	PSCR Factor (Residential)	17.67	Mills/kWh
10	2005 PSCR Undercollection Reconciliation Credit (C&I)	-$12,184	
11	2009 C&I PSCR Sales	32,410	GWh
11	PSCR Factor (C&I)	17.29	Mills/kWh

('$000' omitted)

Case No.	**U-15677**
Exhibit No.	**A-4 (KDJ-2)**
Witness	**K. D. Johnston**
Page No.	**1 of 1**

Detroit Edison Company
Power Supply Cost Recovery Factor
Forecast 2010 through 2013

Line No.		2010	2011	2012	2013	
1	Forecast Year Power Supply Costs (adjusted for R-10, other interruptible & third party sales)	$1,845,994	$2,012,078	$2,084,183	$2,029,383	
2	Projected Prior Year PSCR (over)/undercollection	$0	$0	$0	$0	
3	Total Power Supply Costs	$1,845,994	$2,012,078	$2,084,183	$2,029,383	
4	Net System Requirement (adjusted for R-10, other interruptible & third party sales)	50,848	50,154	49,947	49,513	GWh
5	Unit Cost of Power Supply	36.30	40.12	41.73	40.99	Mills/kWh
6	Base Unit Cost	17.32	17.32	17.32	17.32	Mills/kWh
7	Unit Cost Above (Below) Base	18.98	22.80	24.41	23.67	Mills/kWh
8	Loss Multiplier	1.072	1.072	1.072	1.072	
9	PSCR Factor	20.35	24.44	26.17	25.37	Mills/kWh

('$000' omitted)

S T A T E O F M I C H I G A N

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 2009 Metered Jurisdictional Sales of Electricity	))))))	Case No. U-15677

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

MICHAEL W. SHIELDS

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF MICHAEL W. SHIELDS

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

A. My name is Michael W. Shields. My business address is 2000 Second Avenue, Detroit, Michigan 48226. I am testifying on behalf of The Detroit Edison Company ("Company" or Detroit Edison").

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. What is your current position at Detroit Edison?

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

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. Following the completion of the startup testing programs, I served as a plant reactor engineer, responsible for providing technical support to the operations staff for reactor startups and nuclear core testing and operations.

Line No.

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. My primary responsibility was to develop the Reactor Engineering and Power Ascension testing programs for Fermi 2. In this role, I was also responsible for the overall coordination of the initial fuel delivery at Fermi 2 as well as the coordination of the initial fuel loading.

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.

In 1999 the Customer Energy Solutions – Sourcing function became part of the Generation Optimization group. In addition to the other responsibilities referenced above, I 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 Market. This includes: coordinating any updates needed to register Detroit Edison assets as part of the MISO Asset registration process; and coordinating the Financial Transmission Rights (FTR) registration and management processes necessary for Detroit Edison to obtain FTRs to protect against high congestion costs in the MISO markets. I also work

Line No.

with other groups in the Company in developing bidding strategies for the MISO market, 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 Energy Market. In May 2007 I was elected by MISO stakeholders to serve as the Chair of the MISO Market Subcommittee, which is one of the major stakeholder committees dealing with MISO market-related issues.

Q. Have you been involved in prior proceedings before the Commission?

A. Yes. I have sponsored testimony in the Company's most recent general electric rate Case No. U-15244. I also sponsored testimony in the Commission's Detroit Edison show cause Case No. U-14838.

In addition I have sponsored testimony in the following Detroit Edison PSCR cases:

- 2008 PSCR Plan Case No. U-15417
- 2007 PSCR Reconciliation Case No. U-15002-R
- 2007 PSCR Plan Case No. U-15002
- 2006 PSCR Reconciliation Case No. U-14702-R
- 2006 PSCR Plan Case No. U-14702

Line No.

1 - 2005 PSCR Reconciliation Case No. U-14275-R

2 - 2005 PSCR Plan Case No. U-14275

3 - 2000 PSCR Plan Case No. U-12121

4 - 1997 PSCR Plan Case No. U-11175

Line No.

Q. What is the purpose of your testimony?

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). Many of the MISO charges I will discuss began with the start of the MISO Energy Market on April 1, 2005.

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. My testimony will address the projected expenses for the period 2009 through 2013. 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 Market.

Q. Are you supporting any Exhibits?

A. I am supporting the following Exhibits:

Exhibit No. A-5 (MWS-1)	Transmission and MISO Energy Market Expense for Years 2009-2013
Exhibit No. A-6 (MWS-2)	MISO Settlement Statement Charges/Credits

Line No.		
1	Exhibit No. A-7 (MWS-3)	MISO Settlement Statement Charges/
2		Credits Projections for Years 2009-2013
3		

4 **Q. Mr. Shields, has the Commission previously approved the recovery of**
5 **transmission expenses as part of the recovery of power supply**
6 **expenses?**

7 A. Yes. Detroit Edison properly includes transmission expense in the PSCR process
8 pursuant to the Commission's November 23, 2004 Order in Case No. U-13808[1]
9 and as subsequently reconciled in Case No. U-13808-R. The Commission also
10 approved the inclusion of transmission and MISO-related costs in Detroit Edison's
11 PSCR process in its September 20, 2005 order in Case No. U-14275 (Detroit
12 Edison's 2005 PSCR Plan case)[2] in the September 26, 2006 order in Case No. U-
13 14702 (Detroit Edison's 2006 PSCR Plan case), in the August 21, 2007 order in
14 Case No. U-15002 (Detroit Edison's 2007 PSCR Plan case) and in the July 29,
15 2008 temporary order in Case No. U-15417 (Detroit Edison's 2008 PSCR Plan
16 case).

17

18 **Q. What is the purpose of Exhibit No. A-5 (MWS-1)?**

19 A. Exhibit No. A-5 (MWS-1) presents the Company's projected 2009 through
20 2013 network transmission expense items and MISO Energy Market Cost
21 items. Schedules 1, 2, 3, 5, 6, 9, 10, 10-FERC, 16, 17, 24, and 26 are

[1] This decision was affirmed by the Michigan Court of Appeals in its July 3, 2007 Opinion, COA No. 264191.
[2] This decision was affirmed by the Michigan Court of Appeals in its August 2, 2007 Opinion, COA No. 265869.

transmission and ancillary service schedules for transmission service under the MISO Transmission and Energy Market Tariff (TEMT) as filed with the Federal Energy Regulatory Commission (FERC). For Schedule 2 (Reactive Power) only the additional cost impacts of this schedule associated with the Independent Power Producers (IPPs) providing this service are included in my exhibit. Later in my testimony I will discuss these schedules and the other MISO Energy Market Cost items in greater detail.

Q. What is the purpose of Exhibit No. A-6 (MWS-2)?

A. The line items on this Exhibit reflect the actual line items included on a typical MISO Settlement Statement associated with the MISO Energy Market charge types. 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 Market.

Q. What is the purpose of Exhibit No. A-7 (MWS-3)?

A. Exhibit No. A-7 (MWS-3) reflects the Company's projections of the more significant MISO Energy Market related charges/credits that are expected to apply for the years 2009-2013. 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.

Line No.

SECTION 1 – BASE TRANSMISSION COSTS

Q. What is the network transmission Schedule 1 expense shown on line 3 of Exhibit No. A-5 (MWS-1)?

A. Schedule 1 is the MISO ancillary service 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, currently $59.4376/MW-Month. I am assuming the current rate will continue through 2009 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 $6.1 million for 2009.

Q. What is the network transmission Schedule 9 expense shown on line 4 of Exhibit No. A-5 (MWS-1)?

A. Schedule 9 describes the MISO network integration transmission service. Each transmission customer taking network service will pay the firm monthly zonal rate defined in the MISO tariff for the zone based upon where the load is physically located, which in Detroit Edison's case is the *ITCTransmission* pricing zone. The Schedule 9 ITC zonal rates are determined annually based on a calculation made using projected ITC costs and certain capital expenditures for the following year, using a process defined by Attachment O

of the MISO tariff. It should be noted that a small portion (approximately $21/MW-month) of the Schedule 9 rate paid by Detroit Edison goes to The Michigan Public Power Agency (MPPA), as a result of their 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, 2009 through December 31, 2009 is $2,541/MW-month. The majority of this rate ($2,520/MW-month, an increase of 7% over the $2,350/MW-month ITC portion of the rate in effect for 2007) is based upon ITC's 2009 forecast expenses in accordance with its FERC-authorized forward-looking Attachment O rate formula. The remainder is that related to the MPPA charge as described above.

For the years after 2009 the Company has made an estimate of what the future rates will be based upon an analysis of ITC's future Operating & Maintenance (O&M) costs and a portion of ITC's capital costs intended for equipment replacement and modifications. It should be noted that the cost impacts of the ITC planned and proposed future transmission projects will be primarily recovered under the Schedule 26 rate, 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.

Line No.

The total Schedule 9 rate applied to the forecasted monthly peak demands is projected to result in approximately $260.7 million of Schedule 9 expense to Detroit Edison to serve its bundled retail customers in 2009.

Q. What is the MISO Schedule 10 expense shown on line 7 of Exhibit No. A-5 (MWS-1)?

A. MISO Schedule 10 expense is the cost recovery adder under which MISO recovers its cost of operation 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, which represents about 40% of the total charge, and the other component is tied to monthly energy usage which represents about 60% of the total charge.

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. Because the 40%/60% split is determined based on the MISO total footprint, the actual cost split for Detroit Edison may vary from 40% demand and 60% energy if the average Detroit Edison load factor differs from the MISO load factor.

Line No.

MISO has projected that the overall Schedule 10 rate for 2009 will be approximately $0.112/MWh, which was calculated based on the total MISO monthly demand and energy split. 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 will be approximately $6.7 million in 2009.

Q. What is the MISO Schedule 10-FERC expense shown on line 10 of Exhibit No. A-5 (MWS-1)?

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 MISO, for 2009 this assessment is estimated to be $0.050 per MWh. For 2009, this charge represents a Detroit Edison expense of $3.7 million.

Line No.

Q. What is meant by the MISO Schedule 2 Adder Expense shown on line 13 of Exhibit No. A-5 (MWS-1)?

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 IPPs that are capable of providing these ancillary services within each transmission pricing zone.

A portion of the Schedule 2 adder rate is based on the FERC-approved revenue requirements to compensate the First Energy Solutions peakers located in Sumpter Township, the CMS Dearborn Industrial Generation plant, and the DTE Energy Services' East China generating units. For 2009 the projected cost associated with the Schedule 2 adder for reactive supply and voltage control services for Detroit Edison retail customers is about $3.8 million.

Q. What are the MISO Schedule 26 Network Upgrade charges involving Transmission cost adders shown on line 16 of Exhibit No. A-5 (MWS-1)?

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, the cost of a new transmission project 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. This proposal (commonly referred to as RECB I) was approved by FERC in an interim order in Docket Number ER06-18 issued on February 3, 2006. The RECB I methodology was reaffirmed by FERC in its Order on Rehearing and Clarification issued on November 29, 2006. Under the RECB I proceedings, 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 would be 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 will be 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 will use 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 Transmission and Energy Market Tariff (TEMT). 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 where *ITC Transmission* serves as the Transmission Owner, 50% of the cost is borne by the Transmission Owner, and the remainder is borne by the Generation Project developer. The 50% cost allocation borne by the Transmission Owner will be allocated regionally in the same manner as discussed above for use with Baseline Reliability Projects.

FERC recently approved a request (Docket No. ER07-1141, dated September 7, 2007) made by ITC and METC to charge its customers for the 50% of the costs that would have otherwise been charged to the Generation Project developer under Attachment FF of the MISO TEMT, with all of the other provisions of Attachment FF remaining the same. At this time the Company is unable to estimate the future cost impacts of this decision on Detroit Edison retail customers.

I have included a projection of the costs associated with Schedule 26 on line 16 of Exhibit No. A-5 (MWS-1). The cost for 2009 is projected to be $22.4 million. The Company's estimates for 2009 and beyond are based on the list of "planned" projects either already approved by the MISO Board of Directors and or are projects that are expected to be approved by the MISO Board of Directors in October 2008 that are associated with the 2008 Midwest ISO Transmission Expansion Plan (MTEP08). The cost sharing allocation developed by MISO for

each project was used in developing the Schedule 26 values.

It should be noted that the Schedule 26 projections not only include the costs to be allocated to Detroit Edison retail customers in the ITC transmission pricing zone related to projects being developed outside of the ITC zone, but also include the cost allocation of ITC projects to ITC customers for those projects that qualify for regional cost sharing as defined above. This will ultimately result in increasing rate levels for Schedule 26 over time as new transmission projects are built.

It should also be noted that Detroit Edison's Schedule 26 cost estimates do NOT include the impacts of the recently proposed American Electric Power (AEP) & ITC *$2.6 billion* 765kV project that proposes to add a 765kV transmission loop to be located primarily across Lower Michigan. This project is still under review by MISO and has not been submitted for approval to the MISO Board.

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 No. A-5 (MWS-1)?

A. Yes. There is another category of transmission projects under the Attachment FF of the MISO TEMT referred to as Regionally Beneficial Projects, which are those projects which are determined by MISO to have significant regional

Line No.

economic benefits that cannot be justified solely as being necessary to meet regional reliability requirements. A filing was made by MISO on November 1, 2006 in Docket Nos. ER06-18-004 and ER06-18-005 reflecting the outcome of the efforts of RECB Task Force in making recommendations on the cost sharing allocation for these types of projects (commonly referred to as RECB II projects). FERC issued an order on March 15, 2007 essentially adopting the cost allocation proposal recommended by MISO. The costs of these projects will eventually be recovered under Schedule 26 of the MISO TEMT, although there is very little information available at this time with regard to any projects that are being justified based on the RECB II criteria.

Although I have not included a cost projection in this filing, MISO has also defined Schedule 25 for use in uplifting transmission costs for large transmission projects built in another RTO region (in particular, the PJM RTO) that are determined to have benefits for load in MISO. The allocation of the benefits of such a project must be mutually agreed upon by the regional transmission planning organizations for the respective RTOs. There is a great deal of uncertainty as to when the details of any cost allocation methodology will be agreed upon between the applicable RTO regions and approved by FERC, so at this time I am unable to include any projections for Schedule 25 charges.

Additional discussion involving a number of transmission pricing issues is being provided in the testimony of Edison witness Mr. Brunell.

Line No.

Q. What are the MISO Schedule 2, 3, 5, and 6 revenues shown on line 19 of Exhibit No. A-5 (MWS-1)?

A. Detroit Edison currently receives certain ancillary services tariff expenses and revenues from MISO associated with Schedule 2 (Reactive Supply and Voltage Control from Generation Sources); Schedule 3 (Regulation and Frequency Response); Schedule 5 (Operating Reserve – Spinning Reserve) and Schedule 6 (Operating Reserve – Supplemental Reserve). The Company's base rates set in the November 23, 2004 final order in MPSC Case No. U-13808 reflected the ancillary service (Schedules 2, 3, 4, 5, & 6) revenues of $10.6 million (2002 MPSC Form P-521 page 331B, line 29 and page 310.1 line 5). The Company has proposed in its main electric rate case, Case No. U-15244, that the revenues and expenses associated with these ancillary services be reconciled in the PSCR process. With the startup of a MISO Ancillary Services market projected to possibly occur as soon as January 2009, it will be more appropriate to include these revenues as part of the PSCR process. The fuel and purchased power expense associated with providing these ancillary services are already included within the PSCR.

In effect, with the advent of the MISO Ancillary Services market, Detroit Edison will be buying Ancillary Services from the MISO market to serve its bundled load and will also be selling Ancillary Services to the MISO Ancillary Services market; with both the buying and selling decisions to be based on market economics. The Company is not including an estimate for this item in this proceeding as the

timing and results of the Company's request to reconcile these ancillary services expenses and revenues as set forth in Case No. U-15244 is uncertain as is the net dollar impacts of the Company's actual participation in the MISO Ancillary Services market.

While the MISO Ancillary Services market proposed for implementation in January 2009 will not directly include the "Reactive Supply and Voltage Control from Generation Sources" ancillary services covered under Schedule 2, it is still appropriate to have these revenues also handled through the PSCR process. Currently, Schedule 2 charges from IPPs located within the ITC transmission pricing zone are included in the PSCR, and, to be consistent, it makes sense to reconcile all Schedule 2 revenues and expenses in the same manner. All Ancillary Services and the related expenses are heavily influenced by the booked cost of fuel; are an integral part of Detroit Edison's power supply requirements; and are therefore also an integral part of the Company's purchased and net interchange power transactions.

Q. What is the Total Base Transmission Cost shown on line 22 of Exhibit No. A-5 (MWS-1)?

A. The Total Base Transmission Cost is the sum of Schedules 1, 2, 3, 5, 6, 9, 10, 10-FERC, the Schedule 2 Adder and the Schedule 26 charges. For 2009 I estimate this cost to be approximately $303.5 million, which is necessary to serve Detroit Edison's full service retail customers. The bulk of this amount

($260.7 million) represents the ITC charges associated with network service.

SECTION 2 - MISO ENERGY MARKET CHARGES & CREDITS

Q. Can you explain how Detroit Edison was 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, 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 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 that generator.

Line No.

Q. What is an FTR?

A. An FTR is a Financial Transmission Right. In the MISO Energy Market one component of the LMP calculation is the cost of relieving any transmission congestion. FTRs are financial instruments that give 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 an 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.

Line No.

As explained later in my testimony, the Company believes that it may need to occasionally purchase additional FTRs to mitigate congestion costs and to support power deliveries made from sources outside of the Detroit Edison service territory. Such FTR purchases are a necessary cost incurred in order for the Company to continue to provide economical full service retail electric power to its customers in the MISO Energy Market environment, and the cost of such purchases should be included in PSCR costs. MISO will conduct annual and monthly FTR auctions to facilitate the purchase of FTRs.

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. Expenses for FTRs are booked in Account 555, Purchased Power.

Q. What is the MISO Schedule 16 expense shown on line 26 of Exhibit No. A-5 (MWS-1)?

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 2009 is projected to be $0.014/FTR-MWh, which is multiplied by the number of hours in each month to obtain the monthly cost.

Line No.

Assuming that the Company is able to obtain its full entitlement in the 2009 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, Detroit Edison will incur approximately $1.3 million of Schedule 16 expense in 2009.

Q. What is MISO Schedule 17 expense shown on line 29 of Exhibit No. A-5 (MWS-1)?

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 2009 will be $0.068/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

Line No.

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 $7.4 million for 2009.

Q. What is the MISO Schedule 24 Balancing Authority Charge shown on line 32 of Exhibit No. A-5 (MWS-1)?

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. This tariff was first put in place in the summer of 2006. MISO is taking all the expense associated with LBA operations across the MISO footprint and uplifting them 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 2009, I am estimating the Schedule 24 rate to be about $0.0119/MWh, which was calculated based on the average of the historical monthly rates from September 2007 through August of 2008. I am projecting

Line No.

the total Schedule 24 expense to Detroit Edison for 2009 to be about $1.3 million.

Q. What are some of the other costs and/or credits that will be experienced when Detroit Edison is operating within the MISO Energy Market?

A. Other costs that will be incurred by Detroit Edison include: 1) FTR procurement costs, 2) 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, 3) Costs (and credits) associated with Congestion costs for LSEs, and 4) Miscellaneous uplift/participant charges and credits that MISO will be imposed on all Market Participants under defined circumstances.

Q. What is the logic for procuring FTRs beyond those provided to Detroit Edison as part of the initial FTR allocation process?

A. The design of any LMP market is intended to directly reflect in the prices charged to LSEs (in this case Detroit Edison) the cost of any transmission congestion. The LMP at each customer load node consists of three components: 1) the energy market clearing price component, 2) the congestion component, and 3) a marginal losses component.

The FTR mechanism was established to help protect LSEs against their exposure to the congestion cost component of LMP, thus lowering their overall costs in the MISO Energy Market. Some FTRs are allocated to MISO LSEs as

Line No.

part of an annual FTR allocation process. MISO Market Participants can also procure FTRs during the MISO FTR auctions.

Based on the information available at this time, the Company is not projecting that additional FTR purchases will be made in FTR auctions for 2009 and beyond. However, as more information becomes available, this position could change should there be a belief in the future that purchases in the FTR auction would serve to provide additional protection against some of the Company's exposure to congestion costs. For this reason, although I am retaining line 35 of Exhibit No. A-5 (MWS-1) as a placeholder, I am not showing any expense for this item.

Q. Can you explain what is meant by MISO uplift/participant charges and how they could 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. 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 uplifted 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 No. A-6 (MWS-2) and Exhibit No. A-7 (MWS-3) I show all the various charges/credits that are calculated by MISO. I will explain some of the more significant charges/credits that are likely to be experienced in 2009 based on current MISO Energy Market information.

Q. Can you explain Exhibit No. A-6 (MWS-2)?

A. Exhibit No. A-6 (MWS-2) 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 Market. 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 past operating days subsequent to the start of the MISO market.

Line No.

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 four categories of charge types and fifty-seven 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 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. There are also several additional charge types related to the Ancillary Services Market that do not specifically fit in the other three categories.

Q. Can you explain Exhibit No. A-7 (MWS-3)?

A. Exhibit No. A-7 (MWS-3) includes certain charge type items that represent some of the more significant MISO Energy market charges that have not been accounted for elsewhere in other cost/credit estimates. In most cases 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, 2007 – August 31, 2008) of the MISO Energy Market.

Line No.

On Exhibit No. A-7 (MWS-3) I am combining some of the related charge types that I have determined to be similar in nature from Exhibit No. A-6 (MWS-2) to develop cost/credit projections for 2009 and beyond. In reviewing Exhibit No. A-7 (MWS-3) 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 No. A-5 (MWS-1), line 38?

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 represents 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

Line No.

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 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 four charge types for the most recent 12 months (September 1, 2007 to August 31, 2008) of the MISO market is a credit to Detroit Edison of about $15.6 million as shown on line 10 of Exhibit No. A-7 (MWS-3) and on line 38 of Exhibit No. A-5 (MWS-1). This credit is largely due to higher RT Revenue Sufficiency Guarantee Make Whole Payments over the last several months as compared to what the Company has received in the past. The Company is assuming this net credit will continue in our projection for the years 2009 and beyond.

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 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 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. Even then, as discussed previously, there is 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 congestion.

Second, 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 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 an FTR that Detroit Edison will typically obtain during the annual allocation process.

Line No.

However, because each FTR is directional, should the opposite congestion situation occur and the LMP value at the source location is higher than the LMP value at the sink location due to congestion, even if only for a short period of time, the FTR holder will have to pay the LMP congestion component between the defined FTR sink and source. 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.

Q. How was the Net Congestion Cost value included on Exhibit No. A-5 (MWS-1), line 41 derived?

A. As can be seen under the heading "Congestion Calculation" in Exhibit No. A-7 (MWS-3), the Company is using the most recent 12 months (September 1, 2007 to August 31, 2008) of historical MISO Energy Market information to develop a projection for 2009 and beyond. The first item under this heading, "Congestion Amount between Generation and Load", reflects the net differential congestion costs between Detroit Edison generation and load. For example, in January 2008 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 $0.920/MWh (DECO.NEC is the name of the commercial price or

Line No.

"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 $460,000 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 2009 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 $0.920/MWh value used in the above example for Monroe Unit 1 for January, 2008. 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 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

Line No.

expense of $3.1 million shown on Exhibit No. A-7 (MWS-3), line 14 for 2009.

Also shown on Exhibit No. A-7 (MWS-3) is the actual congestion costs/credits charge types associated with the historical purchases and sales made in the most recent 12 months (September 1, 2007 to August 31, 2008) 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 19 through 21 of Exhibit No. A-7 (MWS-3). The credit to Detroit Edison from the Company's share of the sale of unallocated ARRs in the annual FTR auction is shown on line 22 of Exhibit No. A-7 (MWS-3). I believe that the net value of all these items, a credit to Detroit Edison of $4.0 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 24 of Exhibit No. A-7 (MWS-3) and is included as line item 41 on Exhibit No. A-5 (MWS-1) to reflect this cost estimate for 2009. Much of this credit is due to an allocation of revenues from the annual FTR auction that took place in May 2008, which is the first time an annual auction of this sort took place within the Midwest ISO.

Q. Are there other congestion charges not captured in the above calculation?

A. Yes. Because of a consistent shortfall in the collection of real-time congestion costs, 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. 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 included later in my testimony.

Q. Can you explain Marginal Losses and how their use for dispatch purposes could 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 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, 2007 to August 31, 2008, and multiplying that difference by the projected net generator Megawatt-hour output for each month in 2009, I have estimated the total marginal losses amount between the generators and the load to be $80.6 million for 2009, as shown under the “Losses Calculation” heading in Exhibit No. A-7 (MWS-3), line 28. 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). Next is the category “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 37 of Exhibit No. A-7 (MWS-3) 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 $33.5 million for 2009, as shown on line 37 of Exhibit No. A-7 (MWS-3).

The net cost for losses in 2009, as shown on line 39 of Exhibit No. A-7 (MWS-3) and as carried over to line 44 of Exhibit No. A-5 (MWS-1) is $15.8 million.

Q. Can you explain the Revenue Neutrality Uplift item on Exhibit No. A-5 (MWS-1), line 47?

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 six different charges and credits included in the generic "Revenue Neutrality Uplift" charge type. These are:

1) Uninstructed Deviation Charge Distribution Uplift
2) Revenue Inadequacy Uplift
3) Joint Operating Agreement (JOA) Uplift
4) Option B Grandfathered Agreement Financial Bilateral Transaction Congestion Rebate Distribution Amount Uplift

Line No.

5) Real-Time Revenue Sufficiency Guarantee Make Whole Payments Second Pass Distribution Uplift

6) Carve-Out Grandfathered Agreement Congestion Rebate Distribution Amount Uplift

For the last twelve months of the MISO Energy Market (September 1, 2007 to August 31, 2008) the RT Revenue Neutrality Uplift Charge was approximately $14.9 million. The Company is using that same value in projecting the cost to Detroit Edison for 2009 and beyond, as shown on Exhibit No. A-5 (MWS-1), line 47.

Q. What is the Total Energy Market Cost value shown on Exhibit No. A-5 (MWS-1), line 50?

A. This is the sum of the costs associated with Detroit Edison participating in the MISO Energy Market. During 2009 the cost to Detroit Edison is estimated to be approximately $21.0 million. This is the cost that Detroit Edison incurs as a participant in the regional energy market.

Q. What is the Total Base Transmission and MISO Energy Market Costs shown on Exhibit No. A-5 (MWS-1), line 53?

This is the total cost associated with procuring transmission services from MISO/ITC and participating in the MISO Energy market. As shown on line 53, the total cost is estimated to be approximately $324.6 million for 2009.

Line No.

Q. Have any items on Exhibit No. A-6 (MWS-2) been 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 Edison witness Ms. Wojtowicz's testimony and exhibits.

Q. Which charge type items on Exhibit No. A-6 (MWS-2) have been addressed elsewhere in your testimony?

A. I have previously provided an estimate of the 2009 costs for MISO Schedules 16 and 17. The DA Market Administration Amount and the RT Market Administration Amount have been discussed previously as the charge types associated with MISO Schedule 17. The DA and RT Schedule 24 Allocation Amounts have been discussed previously as the charge types associated with MISO Schedule 24. Likewise, the FTR Market Administration Amount is the charge type discussed for MISO Schedule 16.

Q. What are the charge types on Exhibit No. A-6 (MWS-2), 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

Line No.

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 2009 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 Market Rules, even after the market has been in operation for several years. The TEMT is still evolving and, as a result, there may be additional cost impacts to Detroit Edison in 2009 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 Market.

When these additional MISO and/or ITC-related charges do occur, they should

Line No.

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 market and to provide retail electric service to Detroit Edison's full service customers.

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

A. All of the expense items listed on Exhibit No. A-5 (MWS-1) and Exhibit No. A-6 (MWS-2) 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 grid.

Q. Does this complete your testimony?

A. Yes, it does.

S T A T E O F M I C H I G A N

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 2009 Metered Jurisdictional Sales of Electricity	))))))	Case No. U-15677

EXHIBITS

OF

MICHAEL W. SHIELDS

Michigan Public Service Commision
The Detroit Edison Company
Transmission and MISO Energy Market Expense
Years 2009 - 2013

Case No.: U-15677
Exhibit No.: A-5 (MWS-1)
Witness: M.W. Shields
Page: 1 of 1

	2009	2010	2011	2012	2013
BASE TRANSMISSION COSTS					
MISO Network Transmission					
Schedule 1 x $1000	$6,098	$6,186	$6,213	$6,331	$6,414
Schedule 9 x $1000 (ITC Zone)	$260,697	$244,098	$239,048	$235,203	$229,863
MISO Schedule 10					
x $1000	$6,708	$6,600	$6,471	$6,124	$6,055
MISO Schedule 10 - FERC Transmission					
x $1000	$3,749	$3,717	$3,656	$3,640	$3,585
Schedule 2 Adder					
x $1000	$3,810	$3,786	$3,749	$3,757	$3,734
Schedules 26 - Network Upgrade Charges					
x $1000	$22,441	$23,765	$23,540	$27,209	$27,034
Schedules 2, 3, 5, and 6 Revenues					
x $1000	$0	$0	$0	$0	$0
Total Base Transmission					
x $1000	**$303,503**	**$288,152**	**$282,678**	**$282,264**	**$276,686**
MISO ENERGY MARKET COSTS					
MISO Schedule 16					
x $1000	$1,309	$1,381	$1,257	$975	$952
MISO Schedule 17					
x $1000	$7,375	$7,331	$7,134	$5,940	$5,892
Schedule 24 - Local Balancing Authority Charges					
x $1000	$1,294	$1,286	$1,271	$1,266	$1,256
FTR Purchases					
x $1000	$0	$0	$0	$0	$0
Net Rev. Sufficiency Guar. & Make Whole payments					
x $1000	($15,607)	($15,607)	($15,607)	($15,607)	($15,607)
Net Congestion Cost					
x $1000	($3,972)	($3,972)	($3,972)	($3,972)	($3,972)
Net Losses Cost					
x $1000	$15,794	$16,107	$17,086	$15,011	$15,688
RT Revenue Neutrality Uplift Amount					
x $1000	$14,856	$14,856	$14,856	$14,856	$14,856
Total Energy Market Costs					
x $1000	**$21,049**	**$21,382**	**$22,026**	**$18,470**	**$19,064**
Total Base Transmission & MISO Mkt Costs					
x $1000	**$324,553**	**$309,533**	**$304,704**	**$300,733**	**$295,750**

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

Michigan Public Service Commision
The Detroit Edison Company
MISO Settlement Statement Charges/Credits
Projections for Years 2009 - 2013

Case No. U-15677
Exhibit No.: A-7 (MWS-3)
Witness: M.W. Shields
Page: 1 of 1

Line No.			2009	2010	2011	2012	2013
1							
2			($ x1000)	($ x1000)	($ x1000)	($ x1000)	($ x1000)
3	**Revenue Sufficency Estimate Calculation**						
4							
5	DA Revenue Sufficiency Guarantee Distribution Amount	Sep 07 - Aug 08	1,759	1,759	1,759	1,759	1,759
6	DA Revenue Sufficiency Guarantee Make Whole Payment Amount	Sep 07 - Aug 08	(96)	(96)	(96)	(96)	(96)
7	RT Revenue Sufficiency Guarantee First Pass Dist Amount	Sep 07 - Aug 08	7,239	7,239	7,239	7,239	7,239
8	RT Revenue Sufficiency Guarantee Make Whole Payment Amount	Sep 07 - Aug 08	(24,509)	(24,509)	(24,509)	(24,509)	(24,509)
9							
10		**Total**	**$ (15,607)**	**$ (15,607)**	**$ (15,607)**	**$ (15,607)**	**$ (15,607)**
11							
12	**Congestion Calculation**						
13							
14	Congestion Amount between Generation and Load		3,141	3,190	3,275	3,079	2,742
15	DA Financial Bilateral Transaction Congestion Amount	Sep 07 - Aug 08	2,891	2,891	2,891	2,891	2,891
16	RT Financial Bilateral Transaction Congestion Amount	Sep 07 - Aug 08	682	682	682	682	682
17	DA Congestion Rebate on Carve-out GFA	Sep 07 - Aug 08	(2,752)	(2,752)	(2,752)	(2,752)	(2,752)
18	RT Congestion Rebate on Carve-out GFA	Sep 07 - Aug 08	(682)	(682)	(682)	(682)	(682)
19	FTR Hourly Allocation Amoun	Sep 07 - Aug 08	(3,448)	(3,448)	(3,448)	(3,448)	(3,448)
20	FTR Monthly Allocation Amount	Sep 07 - Aug 08	(781)	(781)	(781)	(781)	(781)
21	FTR Yearly Allocation Amount	Sep 07 - Aug 08	(7)	(7)	(7)	(7)	(7)
22	FTR ARR Stage 2 Distribution	Sep 07 - Aug 08	(3,016)	(3,016)	(3,016)	(3,016)	(3,016)
23							
24		**Total**	**$ (3,972)**	**$ (3,923)**	**$ (3,837)**	**$ (4,034)**	**$ (4,371)**
25							
26	**Losses Calculation**						
27							
28	Marginal Losses Amount between Generation and Load		80,591	81,056	82,535	78,086	79,191
29	DA Financial Bilateral Transaction Loss Amount	Sep 07 - Aug 08	7,606	7,606	7,606	7,606	7,606
30	RT Financial Bilateral Transaction Loss Amount	Sep 07 - Aug 08	883	883	883	883	883
31	DA Loss Rebate on Carve-out GFA	Sep 07 - Aug 08	(7,189)	(7,189)	(7,189)	(7,189)	(7,189)
32	RT Loss Rebate on Carve-out GFA	Sep 07 - Aug 08	(883)	(883)	(883)	(883)	(883)
33	RT Distribution of Losses Amount	Sep 07 - Aug 08	(31,754)	(31,754)	(31,754)	(31,754)	(31,754)
34							
35		Subtotal	$ 49,255	$ 49,720	$ 51,198	$ 46,750	$ 47,855
36							
37	Revenue for Transmission Losses		$ (33,461)	$ (33,613)	$ (34,112)	$ (31,739)	$ (32,167)
38							
39		**Total**	**$ 15,794**	**$ 16,107**	**$ 17,086**	**$ 15,011**	**$ 15,688**
40							
41							
42	**RT Revenue Neutrality Uplift Amount**	Sep 07 - Aug 08	**$ 14,856**	**$ 14,856**	**$ 14,856**	**$ 14,856**	**$ 14,856**

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 2009 Metered Jurisdictional Sales of Electricity	))))))	Case No. U-15677

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

SHERRIE L. SIEFMAN

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF SHERRIE L. SIEFMAN

Line No.

Q. Please state your name and business address.

A. My name is Sherrie L. Siefman. My business address is 2000 Second Avenue, Detroit, Michigan 48226.

Q. By whom are you employed and in what capacity?

A. I am employed by The Detroit Edison Company as 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 in 1981. I received a Master of Business Administration degree with a concentration in Accounting from Wayne State University in 1984. 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. I also performed analyses of system generation, load and costs.

In January 1983, I transferred to the Revenue Requirement Department. I prepared

Line No.

workpapers and exhibits supporting the cost of service study and working capital in General Electric Rate Case No. U-7660 and in a filing with FERC.

In January 1984, I was promoted to Business Analyst. In this position, I performed a depreciation study, compared costs with other utilities, calculated fixed charge rates and analyzed the PSCR over/under recovery position. I coordinated cases before the MPSC, including a depreciation case and a PSCR case. During this time, I had cross-training assignments in the Rate Department and Load Research.

In April 1986, I was promoted to Economic Analyst. I performed asset valuations, (e.g., substations, transformers). 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 a depreciation study and provided support for a depreciation case. I analyzed fixed charge rates and investment for cost sharing with Consumers Energy for the Michigan Electric Power Coordination Center (MEPCC). I continued to coordinate cases before the MPSC, including finance cases and PSCR reconciliation cases. I was the back-up to the rate witness in the 1986 PSCR and SCR reconciliation cases and in the 1988 PSCR and SCR plan cases. I prepared workpapers and exhibits supporting working capital and historical revenue deficiency in General Electric Rate Case No. U-8789. I was a back-up witness in the Michigan Residential Conservation Service reconciliation, Case No. U-6633-R.

In May 1990, I was promoted to Senior Economic Analyst. In October 1993,

Line No.

through a re-organization, I assumed the position of Cost Analyst in Regulatory Compliance. I continued to perform the monthly analysis of PSCR and SCR revenues and costs and fixed charge rates and investment for cost sharing with Consumers Energy for the MEPCC. I was the back-up witness in several Expense Stabilization Procedure cases. I served on a task force which looked at operations and costing of the Michigan Electric Coordinating System. I prepared workpapers and exhibits supporting working capital in General Electric Rate Case No. U-10102 and was a back-up to the rate witness in the 1993 PSCR Plan case. I sponsored direct testimony and exhibits in the 1991 SCR Reconciliation Case No. U-9777-R, the 1992 SCR Reconciliation Case No. U-9981-R, the 1993 SCR Plan Case No. U-10174 and the 1994 SCR Plan Case No. U-10460. I managed several cases including a depreciation case, demand-side management plan and reconciliation cases, and the Intelligent Link Project case.

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 utility costs, sales, revenue and generation; tracked utility mergers and 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

Line No.

sales.

In November 2000, through a re-organization, I was transferred to Market Intelligence. While there, I used the tracking of capacity additions and changes to analyze reserve margins and develop expansion plans for use in PROMOD to forecast electricity market clearing prices. I was responsible for maintaining the MAIN region in the 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

Line No.

knowledgeable load forecasters. I am also a member of the Detroit Association for Business Economics (DABE). DABE discusses economic issues affecting Southeastern Michigan.

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

A. I have assisted in preparing testimony and exhibits and have served as a back-up for the Company witness addressing the electric sales and system output forecast in General Electric Rate Case No. U-13808, the 2005 PSCR Plan Case No. U-14275, the 2006 PSCR Plan Case No. U-14702, the 2006 Show Cause Case No. U-14838 and General Electric Rate Case No. U-15244. I sponsored testimony and exhibits in the 2007 PSCR Plan Case No. U-15002 and the 2008 PSCR Plan Case No. U-15417.

Line No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide Detroit Edison's current electric sales and system output forecast for the period 2008-2013 and to explain the basis for this forecast.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit No. A-8 (SLS-1)	Summary of service area annual electric sales, output, and demand
Exhibit No. A-9 (SLS-2)	Monthly distribution of service area electric sales and output
Exhibit No. A-10 (SLS-3)	Summary of economic outlook
Exhibit No. A-11 (SLS-4)	Summary of Detroit Edison annual electric sales, output, and demand
Exhibit No. A-12 (SLS-5)	Summary of Electric Choice annual sales
Exhibit No. A-13 (SLS-6)	Service area Energy Optimization sales and demand reductions

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

A. Yes, they were.

Q. Can you describe Exhibit No. A-8 (SLS-1)?

A. Yes. Exhibit No. A-8 (SLS-1) shows service area annual electric sales for the four

Line No.

major rate classifications: Residential, Commercial, Industrial, and Other. Total sales, net system output (NSO), and annual peak demand are also shown. The years 1999 through 2007 are historical; 2008 is a combination of seven months historical and five months forecast; and 2009 through 2013 are forecast. All historical sales, NSO and annual peak demands are actual (not temperature-normalized). Sales and NSO for the first seven months of 2008 are actual. 2008 peak demand is actual (not temperature-normalized). All forecasted values assume normal temperatures.

Q. Can you describe Exhibit No. A-9 (SLS-2)?

A. Yes. Exhibit No. A-9 (SLS-2) shows monthly service area electric sales and net system output for each year of the forecast. 2008 is a combination of seven months historical and five months forecast. The monthly sales and net system output are consistent with the annual projections given in Exhibit No. A-8 (SLS-1).

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

A. Yes, it is.

Q. Can you describe Exhibit No. A-10 (SLS-3)?

A. Yes. Exhibit No. A-10 (SLS-3) shows the major economic parameters used in the forecast models. The years 1999 through 2007 are historical. The years 2008 through 2013 are forecast.

Line No.

Q. Can you describe Exhibit No. A-11 (SLS-4)?

A. Yes. Exhibit No. A-11 (SLS-4) shows Detroit Edison annual electric sales for the four major rate classifications, net system output (NSO) and peak demand. These sales are calculated as service area sales less Electric Choice sales. The years 1999 through 2007 are historical; 2008 is a combination of historical and forecast, as described above; and 2009 through 2013 are forecast. All historical sales, NSO and annual peak demands are actual (not temperature-normalized). Sales and NSO for the first seven months of 2008 are actual. 2008 peak demand is actual (not temperature-normalized). All forecasted values assume normal temperatures.

Q. Can you describe Exhibit No. A-12 (SLS-5)?

A. Yes. Exhibit No. A-12 (SLS-5) shows Electric Choice annual sales for the four major rate classifications. 1999 through 2007 are historical; 2008 is a combination of historical and forecast, as described above; and 2009 through 2013 are forecast. All historical sales are actual (not temperature-normalized). Sales for the first seven months of 2008 are actual. All forecasted values assume normal temperatures.

Q. Can you describe Exhibit No. A-13(SLS-6)?

A. Yes. Exhibit No. A-13 (SLS-6) shows service area Energy Optimization sales reductions for the four major rate classifications and service area peak demand reductions.

Line No.

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

A. Electric sales are forecast to decrease from temperature-normalized sales of 53,770 GWh in 2007 to 51,925 GWh in 2013. This represents a 0.6% average annual decrease in sales. Sales in each major rate classification are also expected to decrease on an average annual basis: Residential Class by -0.8%; Commercial Class by -0.4%; Industrial Class by -0.6%; and Other Class by -0.1%.

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. Forecast models are developed employing the appropriate regression equations.

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

The forecast is developed separately for each of four main categories: manufacturing, non-manufacturing, Residential Class, and Other Class. Sales in

Line No.

the manufacturing sector are forecast by developing subcategory models 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 models at the two-digit Standard Industrial Classification (SIC) level for fifteen 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 37 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 forecasting model 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.

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,

Line No.

powertrain/drivetrain plants, research and administrative facilities (auto tech), other parts plants and parts suppliers, foundries, and other transportation plants. Energy sales for the groups identified above were forecast using regression-based models with automotive production, other economic indicators and time as explanatory variables. Additional effects from announced plant closings or expansions, plant specific information and displacement generation were also factored into these models. Other automotive plants' sales were forecasted as a constant 15.6% of Primary Class automotive sales based on the historical pattern. Commercial Class automotive sales were forecast as a constant 2.3% of Primary Class automotive sales based on the historical pattern.

Q. How was the Residential Class forecast developed?

A. Energy sales in the Residential Class were forecast by an end-use method including 37 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 electric use per appliance. For each appliance, the product of these three forecast values yields the annual electric sales. The total for all appliances is the total annual Residential Class electric sales. This end-use approach incorporates projected increases in energy efficiency of the various appliances into the total Residential Class electric sales.

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

A. Once the electric sales forecast equations are established, it is then necessary to

Line No.

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 is growing more slowly after expanding by over 2% in both 2006 and 2007. The rate of growth has slowed because of the well publicized housing market slump and subsequent credit crunch, high energy prices, and subtly increasing core inflation. Core inflation is a particularly useful indicator, since it excludes volatile food and energy prices.

Housing prices continue to fall, thus reducing homeowners' equity and overall wealth. This, in turn, dampens growth of personal consumption expenditures, the largest component of gross domestic product.

Gasoline prices are fluctuating at historically high levels, adding both real and psychological barriers to consumer spending. Expensive gasoline has motivated many vehicle buyers to opt for passenger cars instead of light trucks and has kept some potential buyers out of the new vehicle market altogether. Vehicle sales through the first half of 2008 reached 7.4 million units, as compared to 8.2 million units in the same period of 2007, a 10% reduction.

Gross private domestic investment through the first two quarters of 2008 was $1.73 trillion, compared to $1.81 trillion over the same period in 2007. This decline

Line No.

is attributable to a double-digit percentage drop in residential fixed investment, a reflection of the troubled housing sector's impact on the economy.

The federal government's deficit continues to expand, as expenditures outpace revenues. Springtime tax rebates have compounded the effect by further reducing revenues.

Successive cuts in the federal funds rate have accelerated devaluation of the dollar. Combined with robust global growth, this dollar devaluation has not only stimulated exports but granted a reprieve to some American manufacturers, who now find themselves able to compete with foreign firms located in lower-wage regions.

The overall inflation rate began to pick up around the middle of 2008, largely due to the impact of energy price inflation on other sectors of the economy. The price of a barrel of West Texas Intermediate crude oil rose from $64.96 to $123.96 from the second quarter to 2007 to the second quarter of 2008, an increase of 90%. Faced with burdensome energy and materials costs from the run-up in oil prices, firms eventually have had to pass along these costs to their customers.

Q. What is the outlook for the nation's economy in 2009?

A. The current housing downturn and ensuing financial turmoil are projected to constrain the economy into 2009. Furthermore, as credit conditions further tighten

Line No.

and the lift from spring-summer tax rebates in 2008 dies out, the groundwork is being set for a very weak, possibly negative, first-quarter growth in 2009.

After struggling through the first quarter, the economy is expected to pick up steam at mid-year as housing prices hit bottom and the Fed's string of rate decreases finally loosens up lending practices. Lower oil prices should also support growth. In 2009, these influences are forecasted to propel growth of GDP to 1.0%, disposable personal income to 0.5%, and personal consumption expenditures to 0.4%.

The forecast calls for total U.S. unit output of automobiles to eke out a 1.1% gain in 2009, as foreign transplants continue to take market and production share from the domestic Big Three. Transplant production is forecasted to rise by 3.4% and Big Three production to decline by 0.7%.

Housing remains in the spotlight as a significant drag on growth. As a consequence of the federal government's takeover of Fannie Mae and Freddie Mac, mortgage rates are likely to decline moderately and provide a longer term boost to housing prices. The result will not be instantaneous, though, and housing starts will likely bottom out in the last quarter of 2008 and increase at a crawl throughout 2009.

Thanks to an already weak dollar being further devalued by a rapid fire series of federal funds rate decreases, foreign trade has been able to keep the economy out

Line No.

of a recession. As global growth slows, even to the point where major trading partners Japan and Germany flirt with recession, less can be expected from the export sector in the way of boosting the overall economy. The dollar will likely pull out of its long decline and undergo a run of growth beginning in 2009. Combined with the weakening global economy, this portends stiffer headwinds for export industries and a lower contribution to GDP from net exports.

State and local governments, squeezed between slowing revenue growth and more expensive financing, seem destined for major spending cuts in 2009. This will exert yet another negative impact on overall GDP growth.

The Consumer Price Index (CPI) for All Urban Consumers is forecasted to rise by only 3.0% in 2009, as oil prices retreat from their early and mid-2008 explosion. Looseness in the economy is also expected to contribute to more moderate inflation readings.

A progressively uncertain geopolitical climate raises more than the usual caution about oil prices. After ascending rapidly around the middle of 2008, prices began to fluctuate in late summer. Although some commentators had contended that the price run-up was temporary and that prices would soon decline, doubt exists as to whether the fluctuations signal the expected decline. Add in the specter of further Russian military activity in neighboring states, and considerable upside risk to oil prices still exists.

Line No.

Q. What is the outlook for Southeast Michigan's economy in 2009?

A. Retrenchment by the domestic Big Three automakers continues to depress Southeast Michigan's economy. Prospects for recovery in 2009 are very low, as vehicle sales face another depressed year under the combined weight of high gasoline prices, consumer debt, and interest rates.

Perhaps the most visible impact on the Detroit area of hard times at the Big Three is the continuing run of job losses. In 2009, manufacturing jobs are expected to decline by 3.2%. Just to clarify, those are jobs of actual manufacturing workers and do not include the accountants, engineers, lawyers, and other white collar employees who work in the manufacturing industries and are also expected to be laid off in 2009.

Natural resources, mining, and construction payrolls are expected to decline by 2.8%. Most of the jobs in this category are in construction. The housing industry's struggle, so widely reported in the popular news media, underlies many of these layoffs. Even as the nation's housing industry foresees reason for hope in 2009, the depressed state of Detroit's auto industry will delay local recovery to a later year.

Caught up in the Big Three's troubles, private non-manufacturing employment is headed for a 1.0% decline in 2009. Although it is not unprecedented for these service jobs to make gains while manufacturing contracts, the malaise that has

Line No.

settled upon the overall economy will be so pervasive next year that even resilient service payrolls will shrink.

Spending by state and local government cannot escape these economic strains, and jobs at state and municipal levels are expected to decline by 0.6% in 2009.

The forecasted change in total employment, which includes manufacturing, natural resources, mining, construction, private services, and government, amounts to a loss of 1.2%.

Detroit's car and light truck production, to which so much of the region's economy is linked, appears headed for another decline in 2009. For several years, the Big Three had been losing ground to the foreign competitors. The rate of loss accelerated in 2008 and is likely to continue in 2009 because of the domestics' emphasis on large SUVs. The unanticipated hike in gasoline prices has relegated many of the Big Three's heavyweight products to the bottom of consumers' shopping lists. To make matters worse for Southeast Michigan, the product mix of local assembly plants emphasizes these unpopular SUVs. For this reason, the forecast calls for a 2.4% decline in local unit light vehicle production in 2009.

Much of Detroit's steel production supplies the automobile industry but is not inextricably tied to autos. Given sufficient time to cultivate non-automotive customers in a strong global market, Detroit's mills can bounce back from their lost automotive business. Benefiting from that global demand, Detroit steel output is

projected to expand by 0.8% in 2009. The projected increase would be larger were it not for the loss of a blast furnace in an industrial accident at a major steel plant in January of 2008.

Southeast Michigan's population is expected to decline for a fourth consecutive year in 2009, this time by 0.3%. Much has been made of the exodus of recent college graduates from the state. Although this loss of talent is disconcerting, it must be remembered that college graduates often leave their home state to sample other parts of the country and ultimately return home. Whether the current crop of émigrés will come back to Michigan depends on the jobs that the state can offer them in the coming years.

Q. What is the outlook for Electric Choice sales for 2008?

A. Based on sales reported through July 2008 and on an extrapolation of the trend for the year, Electric Choice sales should reach 1,417 GWh for the year. On a temperature-normalized basis, Electric Choice sales for 2008 should also be 1,417 GWh.

Q. What is the forecast for Electric Choice sales for 2009 through 2013?

A. The forecast for Electric Choice sales by rate classification is shown on Exhibit No. A-12 (SLS-5).

Q. How was the Electric Choice sales forecast developed?

A. The forecast of Electric Choice sales was developed using a headroom analysis

Line No.

model. The model uses market clearing price and bundled rates for Detroit Edison customers as inputs. Due to the fact that customers will not switch instantaneously because of contractual obligations, customer/supplier inertia or other factors, the model uses a one-year lag between headroom and Electric Choice sales.

The determination of Detroit Edison bundled rates considered the latest customer rates and expected changes in PSCR costs. The Electric Choice retail price utilized a round-the-clock (RTC) market clearing price (MCP) of $57.11/MWh for 2008 up to $61.21 for 2012 based on the forward prices at the end of business on July 31, 2008. Also included were price adders for load following, deadband, transmission and ancillary charges, MISO fees, reserve requirements, transmission and distribution losses and a distribution charge. In addition, a 10%, on average, customer savings threshold was assumed to induce switching from Detroit Edison's bundled service to Electric Choice service or vice versa. With these costs and prices, the model predicts Electric Choice sales of 1,366 GWh in 2009 increasing to 2,335 GWh in 2013.

Q. What are the service area sales reductions for an Energy Optimization program?

A. The service area sales reductions for an Energy Optimization program are shown on Exhibit No. A-13 (SLS-6). The Energy Optimization program included in this forecast would produce a reduction in annual peak demand of 57 MW in 2009. Since the Energy Optimization program would be offered to all customers in Detroit Edison's service area regardless of their generation provider, the service area

Line No.

sales reductions were prorated to both Detroit Edison customers and Electric Choice customers. Specifics regarding the basis for the Energy Optimization program sales reductions are discussed by Edison Witness Mr. Johnston.

Q. What were the actual and projected 2007 Detroit Edison annual sales?

A. Detroit Edison's 2007 Annual Sales were 52,117 GWh. Forecast sales for 2007 were 48,259 GWh. The total variance of 3,858 GWh is disaggregated as follows:

Warmer than normal summer	+568 GWh
Lower Electric Choice sales than budget	+2,658 GWh
New industrial customers	+592 GWh
Economics	+40 GWh
Total	+3,858 GWh

Q. What were the actual and projected 2008 service area peak demands?

A. The 2008 service area peak demand used for the summer planning efforts was 12,580 MW as documented in Detroit Edison's Report on Summer 2008 Capacity Plan submitted in Case No. U-15481.

On July 16, 2008, a service area peak demand of 11,251 MW was recorded. This consisted of an Electric Choice customer demand of 267 MW and Detroit Edison customer demand of 10,984 MW.

The average temperature at Detroit Metropolitan Airport on July 16 was 79°F. The

Line No.

average heat index from 1 pm to 4 pm was also used to better simulate the heat build-up during the hours before the peak load. For July 16, 2008, the average heat index was 90.7°F. The heat index takes into account the interaction between temperature and relative humidity. A regression-based model was utilized to normalize these effects to an 83°F average daily temperature and a 94.3°F average heat index. On a normalized basis, service area demand was 12,467 MW.

The difference between the normalized service area demand and the forecasted peak was 113 MW or 0.9%.

Q. Would you please describe HELM?

A. The Hourly Electric Load Model (HELM) aggregates hourly demand profiles from various sales or end-uses into a system annual loadshape. The annual sales and hourly demand profiles for each sales category or end-use are the key inputs to this model.

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 HELM model. The HELM model produced calendar-based outputs based on historical distributions for each of 24 customer sales categories.

Q. How was the peak system demand forecast made?

A. HELM was used to forecast annual peak demand. HELM was also utilized to

Line No.

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. Peak demand projections do not reflect reductions due to interruptible loads or DSM.

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

n the matter of the Application of	)	
THE DETROIT EDISON COMPANY	)	
for Authority to Implement a Power	)	Case No. U-15677
Supply Cost Recovery Plan in its	)	
Rate Schedules for 2009 Metered	)	
Jurisdictional Sales of Electricity	)	

EXHIBITS

OF

SHERRIE L. SIEFMAN

SUMMARY OF SERVICE AREA ANNUAL ELECTRIC SALES, OUTPUT, AND DEMAND
HISTORICAL: 1999-2007
FORECAST: 2008-2013

LINE NO.	(a) YEAR	(b) RESIDENTIAL	(c) COMMERCIAL	(d) INDUSTRIAL	(e) OTHER	(f) TOTAL	(g) SYSTEM OUTPUT (Million kWh)	(h) PEAK DEMAND (MW)
		ANNUAL ELECTRIC SALES (Million kWh)						
1	1999	14,064	19,547	15,655	2,595	51,861	55,787	11,018
2	2000	13,903	19,862	16,199	2,653	52,616	56,493	10,946
3	2001	14,504	19,635	14,655	2,539	51,332	55,107	11,964
4	2002	15,959	20,485	14,489	2,653	53,586	57,453	11,915
5	2003	15,075	20,260	14,129	2,643	52,107	55,800	11,645
6	2004	15,083	20,452	14,088	2,598	52,222	55,656	11,357
7	2005	16,813	20,812	13,885	2,720	54,229	58,117	12,341
8	2006	15,770	20,498	14,034	3,228	53,530	57,348	12,901
9	2007	16,147	20,914	13,993	3,301	54,355	58,128	12,229
10								
11	2008	15,659	20,329	13,741	3,270	52,999	56,556	11,251
12	2009	15,453	20,336	13,441	3,236	52,465	56,043	12,114
13	2010	15,408	20,353	13,522	3,248	52,531	56,110	12,021
14	2011	15,347	20,332	13,415	3,260	52,354	55,924	11,870
15	2012	15,178	20,262	13,330	3,271	52,041	55,588	11,687
16	2013	15,020	20,158	13,464	3,283	51,925	55,456	11,529

Case No.: U-15677
Exhibit No.: A-8 (SLS-1)
Page No.: 1 of 1
Witness: Sherrie L. Siefman

MONTHLY DISTRIBUTION OF SERVICE AREA ELECTRIC SALES AND OUTPUT
FORECAST: 2008-2013

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	2008 *	4509	4257	4332	3983	3996	4677	5034	4983	4314	4267	4124	4523
2	2009	4357	4005	4311	3973	4199	4590	5045	4969	4275	4218	4079	4444
3	2010	4365	4013	4320	3983	4206	4586	5031	4961	4278	4231	4094	4462
4	2011	4371	4015	4321	3980	4197	4558	4992	4925	4254	4216	4078	4448
5	2012	4353	3994	4302	3960	4174	4518	4939	4879	4225	4199	4063	4436
6	2013	4355	3993	4303	3958	4168	4495	4903	4850	4211	4195	4059	4434

NET SYSTEM OUTPUT (Million kWh)

		JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
7	2008 *	4753	4554	4589	4231	4265	4994	5411	5370	4650	4535	4385	4819
8	2009	4640	4260	4587	4221	4481	4906	5434	5353	4607	4483	4338	4735
9	2010	4649	4269	4598	4231	4488	4900	5419	5344	4610	4496	4352	4754
10	2011	4656	4271	4599	4228	4479	4871	5375	5305	4584	4480	4336	4739
11	2012	4636	4249	4579	4207	4454	4828	5318	5255	4553	4462	4320	4727
12	2013	4639	4247	4579	4205	4448	4801	5278	5222	4538	4458	4316	4725

* Jan - Jul 2008 are actuals

Case No.: U-15677
Exhibit No.: A-9 (SLS-2)
Page No.: 1 of 1
Witness: Sherrie L. Siefman

SUMMARY OF ECONOMIC OUTLOOK
HISTORICAL: 1999-2007
FORECAST: 2008-2013

LINE NO.	(a) YEAR	(b) CHANGE IN REAL GDP (Percent)	(c) U.S. CAR & TRUCK PRODUCTION (Millions)	(d) DETROIT AREA CAR & TRUCK PRODUCTION (Millions)	(e) DETROIT AREA STEEL PRODUCTION (MM Tons)	(f) INDEX OF INDUSTRIAL PRODUCTION (2002=100)	(g) DETROIT AREA TOTAL EMPLOYMENT (Thousands)	(h) DETROIT, MONROE & ANN ARBOR RES. PERMITS (Thousands)	(i) CHANGE IN U.S. CPI-U (Percent)
1	1999	4.4	12.6	2.5	6.1	99.1	2350.7	24.1	2.2
2	2000	3.7	12.4	2.6	6.9	103.6	2406.8	22.5	3.4
3	2001	0.8	11.2	2.1	6.7	100.0	2348.3	20.5	2.8
4	2002	1.6	12.0	2.2	6.5	100.0	2296.3	22.3	1.6
5	2003	2.5	11.8	2.1	6.3	101.1	2269.9	23.6	2.3
6	2004	3.6	11.6	2.0	5.7	103.6	2251.2	25.7	2.7
7	2005	3.1	11.5	2.1	5.8	106.9	2249.7	18.1	3.4
8	2006	2.9	10.8	1.9	5.9	111.1	2204.0	10.2	3.2
9	2007	2.2	10.5	1.8	6.1	113.4	2163.1	5.3	2.8
10									
11	2008	1.1	9.4	1.6	5.9	113.8	2126.3	3.2	4.3
12	2009	1.0	9.5	1.6	6.0	115.0	2101.3	2.9	3.0
13	2010	3.1	9.4	1.5	6.2	119.1	2076.3	2.9	2.3
14	2011	3.1	10.0	1.5	6.2	123.1	2054.5	2.9	2.1
15	2012	2.8	10.6	1.5	6.2	125.6	2040.0	2.9	2.6
16	2013	2.4	11.3	1.5	6.1	127.6	2030.3	3.0	2.6

Case No.: U-15677
Exhibit No.: A-10 (SLS-3)
Page No.: 1 of 1
Witness: Sherrie L. Siefman

SUMMARY OF DETROIT EDISON ANNUAL ELECTRIC SALES, OUTPUT, AND DEMAND
HISTORICAL: 1999-2007
FORECAST: 2008-2013

LINE NO.	(a) YEAR	(b) RESIDENTIAL	(c) COMMERCIAL	(d) INDUSTRIAL	(e) OTHER	(f) TOTAL	(g) SYSTEM OUTPUT (Million kWh)	(h) COINCIDENT PEAK DEMAND * (MW)
		ANNUAL ELECTRIC SALES (Million kWh)						
1	1999	14,064	19,547	15,647	2,595	51,853	55,779	11,018
2	2000	13,903	19,762	16,090	2,653	52,407	56,270	10,919
3	2001	14,504	18,777	14,430	2,539	50,248	53,942	11,845
4	2002	15,958	18,395	13,589	2,653	50,595	54,246	11,256
5	2003	15,074	15,942	12,254	2,643	45,913	49,161	10,414
6	2004	15,082	13,425	11,472	2,598	42,576	46,024	9,667
7	2005	16,812	15,619	12,316	2,720	47,467	50,688	11,070
8	2006	15,769	17,948	13,235	3,228	50,180	53,783	12,364
9	2007	16,147	19,330	13,340	3,301	52,117	55,600	11,869
10								
11	2008	15,659	19,170	13,483	3,270	51,582	55,077	10,984
12	2009	15,453	19,136	13,274	3,236	51,099	54,580	11,830
13	2010	15,408	18,828	13,345	3,248	50,829	54,286	11,664
14	2011	15,347	18,349	13,221	3,260	50,176	53,587	11,410
15	2012	15,178	18,397	13,140	3,271	49,986	53,384	11,253
16	2013	15,020	18,024	13,263	3,283	49,590	52,950	11,033

* Coincident to the Service Area Peak Demand.

Case No.: U-15677
Exhibit No.: A-11 (SLS-4)
Page No.: 1 of 1
Witness: Sherrie L. Siefman

SUMMARY OF ELECTRIC CHOICE ANNUAL SALES
HISTORICAL: 1999-2007
FORECAST: 2008-2013

ANNUAL ELECTRIC SALES (Million kWh)

LINE NO.	(a) YEAR	(b) RESIDENTIAL	(c) COMMERCIAL	(d) INDUSTRIAL	(e) OTHER	(f) TOTAL
1	1999	0	0	8	0	8
2	2000	0	100	109	0	209
3	2001	0	858	226	0	1084
4	2002	1	2090	900	0	2991
5	2003	1	4318	1875	0	6194
6	2004	1	7028	2617	0	9646
7	2005	1	5193	1568	0	6763
8	2006	1	2550	799	0	3350
10	2007	0	1584	653	0	2238
9						
10	2008	0	1159	258	0	1417
11	2009	0	1199	166	0	1366
12	2010	0	1525	177	0	1702
13	2011	0	1984	194	0	2178
14	2012	0	1864	190	0	2055
15	2013	0	2134	201	0	2335

Case No.: U-15677
Exhibit No.: A-12 (SLS-5)
Page No.: 1 of 1
Witness: Sherrie L. Siefman

SERVICE AREA ENERGY OPTIMIZATION SALES AND DEMAND REDUCTIONS
HISTORICAL: 1999-2007
FORECAST: 2008-2013

LINE NO.	(a) YEAR	(b) SERVICE AREA SALES REDUCTIONS (Million kWh) RESIDENTIAL	(c) COMMERCIAL	(d) INDUSTRIAL	(e) OTHER	(f) TOTAL	(g) PEAK DEMAND REDUCTIONS * (MW)
1	1999	0	0	0	0	0	0
2	2000	0	0	0	0	0	0
3	2001	0	0	0	0	0	0
4	2002	0	0	0	0	0	0
5	2003	0	0	0	0	0	0
6	2004	0	0	0	0	0	0
7	2005	0	0	0	0	0	0
8	2006	0	0	0	0	0	0
9	2007	0	0	0	0	0	0
10							
11	2008	0	0	0	0	0	0
12	2009	62	79	9	0	150	57
13	2010	157	221	25	0	403	144
14	2011	301	431	48	0	780	279
15	2012	507	698	78	0	1283	451
16	2013	712	966	107	0	1785	622

* Coincident to the Service Area Peak Demand.

Case No.: U-15677
Exhibit No.: A-13 (SLS-6)
Page No.: 1 of 1
Witness: Sherrie L. Siefman

S T A T E O F M I C H I G A N

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 2009 Metered Jurisdictional Sales of Electricity	))))))	Case No. U-15677

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

ANGELA P. WOJTOWICZ

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF ANGELA P. WOJTOWICZ

Line No.

Q. What is your name and 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 Detroit Edison?

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. Please review your employment history.

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.

Line No.

I began my employment with The Detroit Edison Company in 1995 as a System Engineer at the Fermi 2 Nuclear 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, 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 in the Fossil Generation organization. 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,

Line No.

and preparing registration submittals for Detroit Edison's generation assets with the MISO. In 2007 I 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 summer capacity to meet reliability requirements, oversight of Detroit Edison's FTR portfolio, annual balancing of Renewable Energy Certificates (RECs) for the Company's GreenCurrents program, oversight of Detroit Edison's generation asset registration with the MISO, participation on MISO sub-committees, review and advocacy of Company recommendations regarding proposed MISO rules/regulations/business practices, and coordination of the purchase of emission allowances for Detroit Edison.

Q. Have you previously provided testimony to the Commission?

A. Yes. I sponsored testimony in the Detroit Edison Company's 2007 Power Supply Cost Recovery Reconciliation, MPSC case No. U-15002-R.

Line No.

Q. What is the purpose of your testimony?

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 2009. In addition, I am supporting the 2010 through 2013 projection of the system generation, emissions and associated emission allowance expense, and purchase power requirements and associated expense required to serve Detroit Edison 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. Which Exhibits are you supporting?

A. I am supporting the following Exhibits:

Exhibit No. A-14 (APW-1)	Projected Fuel, Net Purchase Power, and PSCR Expense, Years 2009-2013
Exhibit No. A-15 (APW-2)	Forecast of Plant Generation, Years 2009–2013
Exhibit No. A-16 (APW-3)	Summer Resource Plan, Years 2009-2013
Exhibit No. A-17 (APW-4)	Net Purchase Power and Expense, Years 2009-2013
Exhibit No. A-18 (APW-5)	NO_x Emission Allowance Projections Ozone Season, Years 2009–2013
Exhibit No. A-19 (APW-6)	NO_x Emission Allowance Projections Annual,

Line No.

Years 2009–2013

Exhibit No. A-20 (APW-7) Incremental SO_2 Emission Allowance Projections, Years 2009–2013

Exhibit No. A-21 (APW-8) Urea Cost Projections, Years 2009–2013

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 the Company's 2003 General Electric Rate Case No. U-13808, the PSCR expense forecast includes the fuel expense for electric generation, NO_x emission allowance expenses associated with generation, purchased power expense, revenue from third party wholesale power sales, network transmission expenses and MISO Day 1 and Day 2 related costs. The network 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 AESs to serve Electric Choice customers.

In addition, the Company has included the incremental SO_2 emission allowance expense, as approved by the Commission in its September 26, 2006 Order in MPSC Case No. U-14702 (Detroit Edison's 2006 PSCR Plan), as part of the PSCR factor. I support the inclusion of SO_2 emission allowances

Line No.

expenses. Edison Witness Mr. Johnston provides more detail regarding the SO_2 emission allowances expense credit in his testimony.

Lastly, the Company is requesting to recover the expense associated with urea in this proceeding. Urea is a chemical which is used in the operation of the Selective Catalytic Reduction ("SCR") units to reduce NO_X emissions at the Company's Monroe Power Plant. I support the recovery of urea in my testimony.

Q. Can you describe Exhibit No. A-14 (APW-1)?

A. Exhibit No. A-14 (APW-1) is the Projected Fuel, Net Purchase Power, and PSCR expense forecast for the years 2009 - 2013.

Shown on this Exhibit are the annual summaries of:

- System generation as shown on Exhibit No. A-15 (APW-2) and the fuel (electric only) expense as shown on Exhibit No. A-2 (JDG-1) and supported by Mr. Good and Mr. Gailliez. Also shown are the forecasted Ludington Losses associated with the Ludington generation.
- The Net Purchase Power and Expense forecast from Exhibit No. A-17 (APW-4).
- The emission allowance expense projections for seasonal NO_X allowances for the years 2009 – 2013 from Exhibit No. A-18 (APW-5).
- The emission allowance expense projections for annual NO_X allowances for the years 2009 – 2013 from Exhibit No. A-19 (APW-6).

- The incremental emission allowance expense projections for SO_2 allowances for the years 2009 – 2013 from Exhibit No. A-20 (APW-7).
- The urea cost projection from Exhibit No. A-21 (APW-8).
- The bundled transmission expense from Exhibit No. A-7 (MWS-3).
- An expense adjustment for FERC wholesale firm sales.
- An expense adjustment for interruptible sales.
- A transmission adjustment for customers whose rates do not include the PSCR factor.
- The PSCR Fuel and Purchase Power Expense.

Q. Can you describe Exhibit No. A-15 (APW-2)?

A. Exhibit No. A-15 (APW-2) is the forecast of the Company's plant generation for the years 2009 – 2013. I am supporting the annual generation forecast for all of the plants except Fermi 2. Mr. Gailliez developed 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. Good to develop unit fuel cost and fuel expense.

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

Q. Does the Company anticipate any outages exceeding 90 days in 2009?

A. No. The Company does not have any scheduled outages exceeding 90 days in 2009.

Q. Can you describe Exhibit No. A-16 (APW-3)?

A. Exhibit No. A-16 (APW-3) is the resource plan of the Company to supply its summer full service, adjusted peak demand with capacity resources including a planning reserve margin for the years 2009 through 2013. This resource plan is based on the Company's latest load forecast as presented in the testimony of Edison Witness Ms. Sherrie Siefman, the current net demonstrated summer operating capability of Detroit Edison's owned generation resources, interruptible load, and long-term 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

Line No.

electing 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.

Q. Why is this Peak Demand Adjustment made to the full service peak demand forecast?

A. This adjustment is made because the Company is not planning on acquiring long-term resources; either installed generation or purchased power, to supply this demand. For the R-10, LCC, D8, and D3.3, this is consistent with the Summer Capacity Plans that were filed by Detroit Edison with the MPSC and with the projections presented in the Power Supply Cost Recovery ("PSCR") Plan cases for the years 1998, 1999, 2000, 2004, 2005, 2006, 2007, and 2008 and in General Electric Rate Case Nos. U-13808 and U-15244. The Company has decided not to purchase seasonally for its interruptible air conditioning and water heater tariff customers but rather review the utilization of IAC and water heaters on a day ahead operational basis. This decision was based on the discussion in the 21st Century Energy Plan encouraging load serving entities such as Detroit Edison to engage in load management programs, decrease power supply costs by reducing peak demand, and the Company's experience in procuring energy from the maturing MISO energy market. It is also consistent with the strategy that was followed in procuring power supply resources for the summers of 2007 and 2008.

Q. Can the Company interrupt its entire available interruptible load for customers served under interruptible tariffs for economic reasons?

A. No. The only tariffs that allow the Company to interrupt load for economic reasons (rather than reliability reasons) are the D1.1 Interruptible Space Conditioning Service (IAC), the D3.3 Interruptible General Service Rate, and the D5 Water Heating Service Rate. These rates provide a flexible operating tool for providing service to the Company's customers. Depending on energy market costs, the Company may bid this load into the Midwest Independent Transmission System Operator (MISO) day-ahead energy market and evaluate utilization of the interruptible option for the real time energy market.

Alternatively, if the projected day-ahead costs are high, this interruptible load may not be bid into the market at all. The IAC tariff has an operating limitation on interruption which restricts interruption to no longer than 30 minutes per hour and no more than 8 hours in a day. The impact on the IAC customer must also be considered when making the decision to interrupt the IAC customer because the savings to the IAC customer is estimated to be about $35 per year and the IAC customer can switch off the IAC rate to firm service with only 3 days notice. That is, if the IAC is used excessively, IAC customers may be incentivized to switch back to firm service and the IAC tariff could be rendered useless as a load management tool. In addition, the IAC interruptible load is utilized, in a standby mode or actual curtailment, to relieve local distribution area circuit loadings which curtail low voltages or outages on the

distribution system.

The same situation is true for the D5 water heating customers. However, if the water heaters are interrupted, when the interruption is ended, there is approximately a 200% payback load due to the water heaters turning back on to restore hot water. By following this strategy these interruptible loads are available in real time as an operating tool to prudently ensure reliable supply of all customer loads at a reasonable cost.

Q. Has the Company interrupted the IAC and water heaters for economic reasons?

A. Yes. The Company has interrupted the load of IAC and water heater customers for economics.

Q. Can the R-10 and D8 customer loads be interrupted for economics?

A. No. The R-10 and D8 loads comprise approximately 295 MW of load and can only be interrupted at the request of the Company for electric system integrity, i.e. reliability. In addition, the additional energy costs to serve the R-10 and D8 (during capacity deficient periods, which are periods when the Company could request the customer to interrupt) are charged to these customers and credited to the other customers through the power supply cost recovery (PSCR) factor. The R-10 and D8 customers can choose to reduce electric consumption during higher cost periods but if the customer does not, the Company has the

Line No.

obligation to obtain power to serve these customers. The R-10 and D8 loads will be bid into the MISO day-ahead and real time energy markets for supply. If MISO, as the reliability coordinator, issues a Maximum Generation Event with a North American Electric Reliability Company (NERC) Energy Emergency Alert Level 2 (EEA 2), then the Company will request the interruption of the R-10 and D8 loads and the energy purchased from the MISO market will be available to serve other Company loads. The Maximum Generation Event with an EEA 2 is considered to be a system integrity (i.e. reliability) event.

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. Reserves above the peak demand are required due to the uncertainties and contingencies associated with (1) weather and load forecasts, (2) generating unit operation, (3) transmission availability and constraints, and (4) the reliability of external power.

The Midwest Planning Reserve Sharing Group (PRSG) is a group of Load Serving Entities (LSE) which are located within or directly interconnected to the Midwest ISO Reliability Authority Footprint. Officially formed in May of 2007, the group set out to study the collective resources of the Midwest PRSG participants to determine the minimum level of reserve requirements based

upon Reliability Principles and Standards set forth by applicable Reliability Entities. The results of the PRSG Loss of Load Expectation (LOLE) Study recommended a planning reserve margin of 13.7% for the June 2008 through May 2009 planning period for the zone where the Detroit Edison service territory is located.

The MISO will be responsible for performing the LOLE study beginning with the planning year commencing on June 1, 2009. The Company is assuming the same planning reserve margin of 13.7% for 2009, but will adjust seasonal purchases in accordance with the actual study results when they become available.

Q. How were the planning reserve margins shown on Exhibit No. A-16 (APW-3) developed?

A. The reserve margins were calculated as 13.7% of the adjusted peak demand.

Q. What are the total resources required by Detroit Edison?

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.

Line No.

Q. Does the Company's forecast reflect the provision of Electric Choice Operating Reserve as it has in the past?

A. No. The Company's forecast does not include the provision of Electric Choice Operating Reserve. This Electric Choice Operating Reserve is the operating reserve required by MISO Schedules 3, 5, and 6 that transmission customers must provide. It is currently anticipated that the MISO Ancillary Service Market (ASM) will begin operation January 6, 2009 and that the operating reserve required by Electric Choice customers would be purchased by the AESs from the ASM.

Q. What is the net demonstrated summer operating capability of the Company?

A. The Company's total owned summer capability is 11,098 MW. Of the Company's net demonstrated summer capability, 7,973 MW is from fossil steam plants, 1,107 MW is from the Fermi 2 nuclear plant, 917 MW is from the Ludington Pumped Storage Hydroelectric (Ludington) facility, and 1,101 MW is from peakers.

The Michigan Public Power Agency (MPPA) is a joint owner of the Belle River Power Plant. Its ownership entitlement is effectively 18.61% of the capability of the plant (MPPA thus controls 234 MW of the Belle River Power Plant). MPPA's ownership of Belle River is not included in the 11,098 MW of the Company's owned capability.

Line No.

The owned summer capability includes 84 MW of generating capability from the Marysville Power Plant (Marysville). However, the decision has been made to hold Marysville in a cold standby status condition. With the Marysville Power Plant in cold standby status, the Company's 2009 owned summer capability is 11,014 MW.

The Company also has 83 MW of summer capability from P.A.2 contracts; therefore, the total net demonstrated summer operating capability of the Company (owned and P.A. 2 contract) is 11,097 MW.

Q. What do the P.A.2 contracts shown on Exhibit No. A-16 (APW-3) represent?

A. The long term purchased capacity of 83 MW shown on Exhibit No. A-16 (APW-3) is the projected non-utility purchased energy and capacity from PURPA Qualifying Facilities (QFs) that the Company is obligated to purchase under sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978. Included are the projections of energy and capacity from waste-to-energy facilities under existing contracts as specified in 1989 PA 2.

The MPSC has approved the contracts for purchases from the following waste to energy facilities covered by PA 2:

Line No.	Facility	Case	Approved
2	Greater Detroit Resource Recovery	U-10066	8/14/92
3	Riverview Energy Systems	U-10068	8/14/92
4	Amended	U-10879	9/21/95
5	Sumpter Energy Associates (Station #1)	U-10069	8/14/92
6	Amended	U-10879	9/21/95
7	Wayne Energy Recovery	U-10070	8/14/92
8	Lyon Electric Generating	U-10232	2/23/93
9	Amended	U-10879	9/21/95
10	Turbine Power Limited Partnership - Arbor Hills	U-10594	8/03/94
11	Amended	U-10879	9/21/95
12	Ann Arbor	U-10879	9/21/95

Q. What does the Renewable Portfolio Standard (RPS) shown on Exhibit No. A-16 (APW-3) represent?

A. The RPS energy shown on Exhibit No. A-16 (APW-3) is the Company's estimate of the renewable resources that the Company anticipates constructing or obtaining through contracts with renewable energy suppliers.

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 co-generators and qualified small power producers as specified

Line No.

by PURPA, and from waste-to-energy facilities under existing contracts specified in 1989 PA 2. As has been previously discussed, the Commission has approved these purchases. Also, the Company has entered into a 18-month agreement for renewable capacity and energy from the Stoney Corners wind generation project and has requested Commission approval for inclusion of the expense as part of Detroit Edison's power supply costs in its 2008 PSCR Plan Case No. U-15417. The Company renews that request in this proceeding.

Q. What do the Planned Capacity Changes shown on Exhibit No. A-16 (APW-3) represent?

As part of the Company's environmental compliance strategy, the Company expects to commence operation of new Flue Gas Desulfurization Units (FGDs or scrubbers) at Monroe Unit 4 in the spring of 2009, Monroe Unit 3 in the fall of 2010 and Monroe Units 1 & 2 in 2013. The internal load or station power requirements associated with the operation of an FGD has resulted in an expected 14 MW decrease in the summer net demonstrated capability of Monroe Unit 4 in 2009, an 11 MW decrease in the summer net demonstrated capability of Monroe Unit 3 in 2010, and a 22 MW total decrease in the summer net demonstrated capability of Monroe Units 1 & 2 in 2013.

Q. What are the Required Purchases shown on Exhibit A-16 (APW-3)?

A. The Required Purchases are the forecasted amount of capacity needed to be

Line No.

acquired in order to achieve the amount of total resources required to serve Detroit Edison's forecasted adjusted full service customer peak demand. The Company currently anticipates purchasing this capacity seasonally from the wholesale electric power market.

With the passage of the Energy Policy Act of 1992, independent power producers (IPPs) and exempt wholesale generators have built merchant power plants to supply wholesale power to electric utilities and sell into the wholesale electric market or self supply. At this time, forecasting to seasonally purchase power from the wholesale power market is the economic and prudent decision given the uncertainties regarding the amount of Electric Choice load, market prices, and the results of the Michigan 21st Century Energy Plan.

Q. Can you describe Exhibit No. A-17 (APW-4)?

A. Exhibit No. A-17 (APW-4) provides the net purchase power and expense projections for the years 2009 through 2013.

Q. Can you describe the various types of purchases and sales shown on Exhibit No. A-17 (APW-4)?

A. The types of purchases and sales shown on this Exhibit are Wholesale energy purchases, capacity and energy purchases from PURPA Qualifying Facilities, renewable energy purchases, Summer Capacity purchases, MISO Energy Market expenses, and Wholesale energy sales.

Line No.

Q. What are wholesale power purchases and sales?

A. Wholesale 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. These purchases are made for reliability and as economic alternatives to running the Company's own generation.

Wholesale power sales are sales made by the Company to other utilities and wholesale power marketers under FERC approved tariffs. The Midwest Independent Transmission System Operator (MISO or Midwest ISO) 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 (City of Croswell, Village of Sebewaing, 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 from the Wholesale Market were modeled in PROMOD based on projections of the wholesale electric market. The forward

Line No.

market curve for the Michigan Hub represents our best estimate of forward market prices as of the close of business on July 31st, 2008.

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 Case Nos. U-13808 and U-15244, the Show Cause Case No. U-14838, and in the 2005, 2006, 2007, and 2008 Power Supply Cost Recovery Plan Case Nos. U-14275, U-14702, U-15002, and U-15417. 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. What are the PURPA Qualifying Facilities purchases?

PURPA Qualifying Facilities are the projections of energy that the Company is obligated to purchase under sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978. Included are the projections of energy and capacity from waste-to-energy facilities under existing contracts as specified in 1989 PA 2.

Q. What is the Renewable Portfolio Standard (RPS) energy and expense shown on Exhibit No. A-17 (APW-4)?

A. The RPS energy and expense shown on Exhibit No. A-17 (APW-4) is the projection of power generated or purchased from new renewable energy generating resources and the associated expense. One of the recommendations from the Michigan 21st Century Electric Energy Plan was to establish a statutorily required renewable energy portfolio standard implemented by the Commission. The standard is expected to apply to all load serving entities in Michigan, such as Detroit Edison. The standard is expected to require load serving entities to obtain as much as 10% of their energy sales from renewable energy options by the end of 2015. Edison witness Mr. Johnston provides more detail regarding a renewable energy portfolio standard in his direct testimony.

Detroit Edison is purchasing renewable energy credits (REC) from Heritage Sustainable Energy (Heritage) for Detroit Edison's GreenCurrents program. A key element of the GreenCurrents program is to encourage the development and operation of new renewable energy projects in Michigan. Heritage is developing the Stoney Corners Wind Farm Project (Stoney Corners) in Michigan and to help ensure that the facility is developed, Detroit Edison entered into a 18-month purchase power agreement with Heritage for the capacity and energy from Stoney Corners.

Line No.

A separate line item is shown on Exhibit No. A-17 (APW-4) reflecting this 18-month contract between Detroit Edison and Heritage for 5 MW of capacity and the associated energy from Stoney Corners. The Stoney Corners generation forecast is based on a capacity factor of 15%, resulting in a capacity credit of about 1 MW. The projected energy from Stoney Corners in 2009 is 13,140 MWh with an associated energy expense of about $907,000.

The Company renews its request for Commission approval to include the expense for this renewable energy and capacity in the Company's power supply costs in 2009.

Q. What are the Summer Capacity purchases and expenses?

A. The Required Purchases shown on Exhibit No. A-16 (APW-3) is the amount of capacity that the Company plans to purchase to ensure system reliability. For 2009, capacity purchases of 1,720 MW are projected to be required at an average cost for the summer of $25/kW.

Q. What are the MISO Energy Market costs?

A. The MISO Energy Market costs are the expenses the Company incurs as a MISO market participant. The costs associated with the MISO Energy Market as shown in Exhibit No. A-17 (APW-4) 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,

Line No.

and other MISO charges and credits related to participating in the MISO energy market. Edison 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 optimizes the installation of technology-based equipment with the purchase of emission allowances from the market when indicated by economics.

Q. What does Exhibit No. A-18 (APW-5) contain?

A. Exhibit No. A-18 (APW-5) displays the Company's projection of NO_x "ozone season" emission allowance expense for the years 2009 through 2013.

Shown on Exhibit No. A-18 (APW-5) is the following information for the "ozone season" (May – September) projected tons and costs of the allowances: (1) the beginning balance of the Company's allowances, (2) the allowances allocated to the Company, (3) allowances purchased by the Company, (4) the expected allowances to be consumed, (5) the ending balance of the allowances and (6) the net expense of the allowances consumed for the relevant years. The market prices of NO_X "ozone season" emission allowances since 1999 have ranged from below $1,000/ton to over $7,000/ton.

Under the Clean Air Interstate Rule ("CAIR"), or replacement rule, it is likely

there will be separate compliance requirements for the "ozone season," NO_X emissions, and "annual" NO_X emissions.

Q. What does Exhibit No. A-19 (APW-6) contain?

A. Exhibit No. A-19 (APW-6) displays the Company's projection of NO_x "annual" emission allowance expense for the years 2009 through 2013.

Shown on Exhibit No. A-19 (APW-6) is the following information for the annual projected tons and costs of the emission allowances: (1) the beginning balance of the Company's emission allowances, (2) the emission allowances allocated to the Company, (3) emission allowances purchased by the Company, (4) the expected emission allowances to be consumed, (5) the ending balance of the emission allowances and (6) the net expense of the emission allowances consumed for the relevant years. In 2008, the market price of annual NO_x allowances ranged from approximately $2,500/ton to $5,600/ton.

Q. What does Exhibit No. A-20 (APW-7) contain?

A. Exhibit No. A-20 (APW-7) displays the Company's projection of SO_2 emission allowance expense for the years 2009 - 2013.

Shown on Exhibit No. A-20 (APW-7) is the following information for the projected tons and costs of the allowances: (1) the beginning balance of the Company's emission allowances, (2) the emission allowances allocated to the

Line No.

Company, (3) emission allowances purchased by the Company, (4) the expected emission allowances to be consumed, (5) the ending balance of the emission allowances and (6) the net expense of the emission allowances consumed for the relevant years The market price of SO_2 emission allowances has ranged from about $40/ton to $1,600/ton.

Q. Has the Commission approved that SO_2 emission allowance related costs can be recovered in the PSCR process?

A. Yes. The Commission approved the inclusion of incremental SO_2 emission allowance expenses in PSCR costs in PSCR Plan Case No. U-14702. Mr. Johnston discusses the incremental nature of this expense in his testimony.

Q. Does Detroit Edison still believe that the SO_2 emission allowance related costs should be recovered in the PSCR process?

A. Yes. The Company still believes that the SO_2 emission allowance related costs should be recovered in the PSCR process.

Q. Why does Detroit Edison still believe that the SO_2 emission allowance related costs should be recovered in the PSCR process?

One primary generation alternative to utilizing SO_2 emission allowances over and above the allocated level of allowances to meet the Clean Air Act requirements would be to burn lower sulfur, but more expensive, coals. In fact, lower sulfur, but higher priced, coal can be utilized to reduce the need to

Line No.

purchase emission allowances and therefore, the total cost of compliance would be recovered through the PSCR mechanism. While there are some practical limitations, as I discuss later, to the Company's fuel blending capabilities, it is theoretically possible that additional fuel blending could be utilized to avoid some SO_2 emission allowance purchases.

The Company has determined that the least cost compliance strategy to meet SO_2 emission allowance limits is a combination of burning low sulfur coal, installation of emission control technologies and utilizing SO_2 emission allowances. In effect, SO_2 emission allowances are a component of the "as burned" booked cost of coal. The Company's utilization of SO_2 emission allowances (versus burning low sulfur coal) results in a direct savings to the Company's customers in terms of lower delivered fuel costs. In other words, in addition to the emission reductions obtained from the installation of emission control technologies, the purchase of SO_2 emission allowances and higher sulfur coal results in the lowest total compliance costs as compared to utilizing entirely low sulfur, higher cost coals. Accordingly, it is appropriate to recover the prudently incurred costs of the SO_2 emissions allowance expense through the PSCR mechanism.

The utilization of purchased power also has an impact on the quantity of allowances required each year. All other factors being equal, additional purchased power will reduce the number of required SO_2 emission allowances

since the Company will generate less power to serve its load requirement.

Similarly, third party wholesale power sales affect the amount of required allowances. The Company can reduce its bilateral third party wholesale power sales and/or increase bilateral power purchases and thereby reduce its internal generation and hence its need for SO_2 emission allowances. However, real time power purchases and third party wholesale power sales are a result of the economic dispatching of the Company's generating resources by MISO and not by the Company. Clearly, tight integration and optimization among fuel types, purchased power, interconnection sales, and SO_2 emission allowances is required. Furthermore, SO_2 emission allowance expense will shift based on system conditions, fuel prices and purchased power costs. For these reasons the Company believes the PSCR process continues to be the appropriate regulatory mechanism to collectively review these costs and provide for their recovery.

Q. Is Detroit Edison's fossil fuel supply plan based on the Company's purchase and consumption of SO_2 emission allowances?

A. Yes. In order to burn the fuels identified in the Company's fossil fuel supply plan, the Company must acquire and consume SO_2 emission allowances to comply with EPA environmental requirements.

Q. Could Detroit Edison purchase increased quantities of lower sulfur coals and decreased quantities of higher sulfur coals as a means to avoid purchasing the SO_2 emission allowances?

A. As a practical matter, it could not. Wherever possible, the Company's generation units economically blend low, mid, and high sulfur eastern coals with low sulfur western coals. System load requirements, equipment capabilities, environmental regulations, and economics are used to determine the appropriate blend. Low sulfur western coal use is maximized based upon the above-mentioned variables with higher sulfur eastern coal used in the remaining portion of the coal blend. The higher sulfur coals are needed to optimize precipitator performance. The higher heating values that are generally characteristic of the higher sulfur coals purchased by the Company are also needed to optimize boiler and boiler-related equipment performance. Therefore, the replacement of higher sulfur eastern coals with lower sulfur eastern coals can come at the expense of decreased low sulfur western coal use and increase the overall system fuel expense based upon the forecasted system load requirements, coal costs, and SO_2 emission allowance costs.

Q. Could Detroit Edison install equipment such as scrubbers to reduce its reliance on SO_2 emission allowances?

A. Yes. As I previously mentioned, the Company is pursuing its strategy to install equipment to reduce its SO_2 emissions through the installation of scrubbers on Monroe Unit No. 4 in the spring of 2009, on Monroe Unit No. 3 in the fall of

Line No.

2009, and on Monroe Units 1 & 2 in 2013.

To summarize, SO_2 emission allowance costs are a component cost of fuel burned for electric generation which will vary in concert with native generation and market prices. SO_2 emission allowances are an integral part of prudent fuel procurement and utilization evaluations. Just like NO_x emission allowances (approved for recovery through the PSCR process in Case No. U-13808), SO_2 emission allowances are used up or "burned" in the process of burning fuel for electric generation. Again, NO_x emission allowance expenses and SO_2 emission allowance expenses are already approved for inclusion in PSCR expense and should remain so approved.

Q. What are the Company's specific emission allowance purchase plans?

A. The Company will obtain emission allowances sufficiently ahead of the expected need date so that adequate lead time exists to adjust the control technology construction schedule in the event of significant changes in the availability and/or the market prices of emission allowances. Emission allowances will be purchased at levels that will spread the purchase quantities 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 allowance markets. This is intended to provide sufficient procurement flexibility so that market liquidity, allowance vintage price variability and allowance value (in relationship to the cost of emission control technology build alternatives) can

Line No.

be managed on a real time basis.

The strategy, therefore, is to procure the SO_2 allowances needed to meet the 2013 shortfall starting in 2009 (four years ahead), with half of the allowances needed procured by the end of 2009. The remaining half of the 2013 shortfall would be completely covered by the end of 2010 (three years ahead). This would allow time to construct the additional scrubbers at Monroe Unit 1 & Unit 2 if allowance prices were to rise (and stay) above the forecasted scrubber construction cost. Likewise this procurement pattern would continue to cover the shortfalls projected for future years with the 2013 shortfall covered in 2009 and 2010; the 2014 shortfall covered in 2010 and 2011; and so on.

For NO_x the same strategy would pertain, except the procurement lead time is reduced by a year for the difference in control technology construction time.

The Company's projected emission allowance purchases follow this reasonable and prudent strategy with a slight modification in the earlier years to phase into the purchase strategy.

Q. What are the Company's emission allowance purchase needs for "ozone season" NO_x, "annual" NO_x, and SO_2 in 2009?

A. **"Ozone Season" NO_x Emission Allowance Purchases**

The forecast shown on Exhibit No. A-18 (APW-5) indicates a purchase need of

Line No.

2,638 "ozone season" NO_x emission allowances in 2009.

"Annual" NO_x Emission Allowance Purchases

The forecast shown on Exhibit No. A-19 (APW-6) Indicates a need of 13,066 annual NO_x emission allowances in 2009.

SO_2 Emission Allowance Purchases

The forecast shown on Exhibit No. A-20 (APW-7) indicates that there is no purchase need for SO_2 emission allowances in 2009.

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 at 1 for 1. For the period 2015 and out, SO_2 emission allowances of those vintage years will be surrendered at a ratio of 2.86 for 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.

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-18 (APW-5), A-19 (APW-6), and A-20 (APW-7), to supply the

emission allowances consumed, the Company will utilize the allocated emission allowances, emission allowances in inventory and emission allowances purchased from the market. The Company will maintain a certain level of emission allowances in inventory in case of contingencies such as increased generation, emission allowance market illiquidity, or delays of emission reduction equipment installation. Loans and swaps of emission allowances to third parties may continue to be utilized as a way to increase the value of the bank (by receiving additional allowances as interest for the loan/swap).

Q. Will you explain Exhibit No. A-21 (APW-8)?

A. Exhibit No. A-21 (APW-8) displays the Company's projection of urea costs associated with operation of the Selective Catalytic Reduction ("SCR") units at Monroe Units 1, 3, and 4.

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

A. Urea is a solid chemical which the Company converts to ammonia at its Monroe Power Plant. The ammonia is used in the SCRs to convert NO_X to nitrogen and water, thereby reducing NO_X emissions and the associated expense of NO_X emission allowances. As a result, there is a direct tradeoff between the consumption of urea in the SCR 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

Line No.

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.

Q. Are there any other reasons that urea expense should be recovered through the PSCR?

A. Yes. As I have already indicated, urea is only used to reduce the PSCR expense associated with the consumption of NO_X emission allowances. The Company's cost of urea is based in part upon NYMEX natural gas prices and, as such, is subject to variability. In addition, the expense associated with urea will vary with native generation and, potentially, NO_X emission allowance market prices. As a result of this expense variability, it makes eminent sense to include this expense in the overall cost of power supply.

A power supply expense that varies significantly is, by its nature, difficult to predict, and thus it is precisely the type of expense that should be included in the PSCR mechanism in order to help avoid otherwise unnecessary rate cases. Further, because urea expense is an expense which is inextricably linked to the Company's power supply decisions, it is properly reflected in the Company's model for economic dispatch of its generation resources, including

Line No.

the price at which the Company offers its generating units to MISO. To the extent that the Company receives wholesale power sales revenue from MISO in accordance with its offers to MISO and that revenue in turn is used to reduce PSCR expense, it is totally appropriate to include all power supply related expense in the PSCR. Finally, if the costs of urea and/or the expense associated with the consumption of NO_X emission allowances decline, then the benefit will similarly be passed on to customers.

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.

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, the Village of Sebewaing, the city of Croswell, 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 and D8 load and the

Line No.

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 Interruptible Adjustment is forecasted by multiplying the actual Interruptible cost for 2007 ($50.02/MWh) by the ratio of the current RTC market price projection for 2009 ($56.50/MWh) to the actual round-the-clock (RTC) market price in 2007 ($47.57/MWh).

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, LCC, and the city of Detroit Public Lighting Department.

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

A. Yes, the projection is 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 to reliably serve the energy and demand requirements of the Company's customers based on fuel

Line No.

cost, market power costs, and emission allowance costs. The forecast was evaluated based on historical operation and expected changes due to maintenance schedules, fuel costs, market power prices and changes in NSO. The emissions were projected from the economic dispatch taking into account the market price of emission allowances required for generation.

Q. Does this complete your testimony?

A. Yes, it does.

S T A T E O F M I C H I G A N

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 2008 Metered Jurisdictional Sales of Electricity	))))))	Case No. U-15677

EXHIBITS

OF

ANGELA P. WOJTOWICZ

Michigan Public Service Commission
The Detroit Edison Company
Projected Fuel, Net Purchase Power, and PSCR Expense
Years 2009 - 2013

Case No.: U-15677
Exhibit No.: A-14 (APW-1)
Page: 1 of 1
Witness: A.P. Wojtowicz

Line No.	(a)	(b) 2009	(c) 2010	(d) 2011	(e) 2012	(f) 2013
1						
2	Generation & Fuel					
3	- GWh	49,609	49,848	50,653	47,057	47,516
4	- $1,000	$ 1,000,453	$ 1,240,227	$ 1,534,911	$ 1,441,324	$ 1,463,151
5						
6	Ludington Losses					
7	- GWh	(442)	(449)	(438)	(422)	(396)
8						
9	Net Purchase Power					
10	- GWh	5,412	4,887	3,373	6,750	5,830
11	- $1,000	$ 419,010	$ 402,660	$ 298,365	$ 474,875	$ 406,036
12						
13	Emission Allowance					
14	NOx Seasonal - $1,000	$ 3,151	$ 3,829	$ 3,626	$ 2,300	$ 2,065
15	NOx Annual - $1000	$ 48,447	$ 37,164	$ 29,208	$ 25,131	$ 21,157
16	Incremental SO2 - $1,000	$ 2,575	$ 1,078	$ 270	$ 3,207	$ 2,373
17						
18	Urea					
19	- $1,000	$ 6,669	$ 7,571	$ 7,669	$ 6,760	$ 7,582
20						
21	Total System Output					
22	- GWh	54,580	54,286	53,587	53,384	52,950
23	- $1,000	$1,480,305	$1,692,529	$1,874,049	$1,953,597	$1,902,365
24	- $/MWh	$27.12	$31.18	$34.97	$36.60	$35.93
25						
26	Bundled Transmission					
27	- $1,000	$ 303,503	$ 288,152	$ 282,678	$ 282,264	$ 276,686
28						
29	FERC Wholesale Firm Adjustment					
30	- GWh	2,680	2,684	2,690	2,696	2,702
31	- $1,000	$ 72,676	$ 83,687	$ 94,070	$ 98,648	$ 97,081
32						
33	Interruptible Adjustment					
34	Energy - GWh	758	754	744	741	735
35	- $1,000	$ 45,010	$ 45,144	$ 44,798	$ 47,245	$ 46,894
36						
37	Transmission Adjustment					
38	Energy - GWh	1,058	1,055	1,047	1,045	1,040
39	Transmission - $1,000	$ 6,150.81	$ 5,855.44	$ 5,780.92	$ 5,783.81	$ 5,692.89
40						
41	PSCR Fuel & Purchase Power					
42	- GWh	51,143	50,848	50,154	49,947	49,513
43	- $1,000	$1,659,972	$1,845,994	$2,012,078	$2,084,183	$2,029,383
44	- $/MWh	$32.46	$36.30	$40.12	$41.73	$40.99

Michigan Public Service Commission
The Detroit Edison Company
Forecast of Plant Generation
Years 2009 - 2013

Case No.: U-15677
Exhibit No.: A-15 (APW-2)
Page: 1 of 1
Witness: A.P. Wojtowicz
R.Gailliez

Line No.	(a) Plant		(b) 2009	(c) 2010	(d) 2011	(e) 2012	(f) 2013
1							
2	Belle River[1]	GWh	7,702	7,168	7,287	7,030	7,018
3							
4	Fermi 2	GWh	8,843	8,838	9,675	8,867	9,154
5							
6	Greenwood	GWh	134	152	147	129	103
7							
8	Harbor Beach	GWh	199	216	189	164	147
9							
10	Monroe	GWh	18,158	19,284	19,538	17,639	18,233
11							
12	River Rouge	GWh	3,092	3,122	2,561	2,896	2,828
13							
14	St. Clair	GWh	7,288	7,532	7,237	6,811	6,569
15							
16	Trenton Channel	GWh	4,051	3,374	3,857	3,391	3,361
17							
18	Large CT's	GWh	120	130	129	106	89
19							
20	Peakers	GWh	6	9	5	3	1
21							
22	Conners Creek	GWh	16	24	27	21	14
23							
24	Total System	GWh	49,609	49,848	50,653	47,057	47,516
25							
26	Ludington Generation	GWh	1,099	1,134	1,096	1,053	997
27	Ludington Pumping	GWh	1,541	1,583	1,534	1,475	1,393
28	Ludington Losses	GWh	(442)	(449)	(438)	(422)	(396)
29							
30	(1) DECo Ownership Share.						

Michigan Public Service Commission
The Detroit Edison Company
Summer Resource Plan
Years 2009 - 2013

Case No.: U-15677
Exhibit No.: A-16 (APW-3)
Page: 1 of 1
Witness: A.P. Wojtowicz

Line No.	(a)		(b)	(c)	(d)	(e)	(f)
	Required Resources		**2009**	**2010**	**2011**	**2012**	**2013**
1							
2	Peak Demand for service area	MW	12,114	12,021	11,870	11,687	11,529
3							
4	Electric Choice Load	MW	(284)	(357)	(460)	(434)	(496)
5							
6	Interuptible Load	MW	(569)	(623)	(654)	(656)	(674)
7							
8	Adjusted Peak Demand	MW	11,261	11,041	10,756	10,597	10,359
9							
10	Planning Reserve Margin (13.7%)	MW	1,543	1,513	1,474	1,452	1,419
11							
12	Total Required Resources	MW	12,803	12,554	12,230	12,049	11,778
13							
14	**Available Resources**						
15	Owned capability available	MW	11,014	11,000	10,989	10,989	10,989
16							
17	P.A. 2 contracts	MW	83	83	83	83	83
18	Renewable Portfolio Standard	MW	0.75	15	40	93	100
19	Planned Capacity Changes	MW	(14)	(11)	-	-	(22)
20							
21	Total Available Resources	MW	11,084	11,087	11,112	11,165	11,150
22							
23							
24	**Required Purchases**	MW	1,720	1,467	1,118	884	628

Michigan Public Service Commission
The Detroit Edison Company
Net Purchase Power and Expense
Years 2009 - 2013

Case No.: U-15677
Exhibit No.: A-17 (APW-4)
Page: 1 of 1
Witness: A.P. Wojtowicz

Line No.	(a) Purchases & Sales	(b) 2009	(c) 2010	(d) 2011	(e) 2012	(f) 2013
1	**Power Purchases**					
2	Wholesale Purchases (Including MISO)					
3	- GWh	5,524	5,039	3,724	5,831	5,217
4	- $1,000	361,909	331,664	233,974	336,717	293,981
5						
6	PURPA Qualifying Facilities					
7	- GWh	521	610	610	612	610
8	- $1,000	$29,985	$35,098	$35,098	$35,195	$35,098
9						
10	Renewal Portfolio Standards					
11	Landfill Gas - MW		15	40	85	85
12	- GWh		118	315	670	670
13	- $1,000		$8,278	$22,075	$46,910	$46,910
14						
15	Wind - MW				50	100
16	- GWh				131	263
17	- $1,000				$ 9,198	$ 18,396
18						
19	Stoney Corners Wind - MW	5				
20	- GWh	13.14				
21	- $1,000	$ 907				
22						
23	Solar - MW				0.5	0.9
24	- GWh				0.8	1.6
25	- $1,000				$ 55	$ 110
26	RPS Total					
27	- MW	5	15	40	135	186
28	- GWh	13	118	315	802	935
29	- $1,000	$ 907	$ 8,278	$ 22,075	$ 56,163	$ 65,416
30						
31	Summer Capacity					
32	- MW	1,720	1,467	1,118	884	628
33	- $1,000	$ 42,993	$ 55,745	$ 60,355	$ 64,538	$ 58,679
34						
35	MISO Energy Market					
36	- $1,000	$21,049	$21,382	$22,026	$18,470	$19,064
37						
38	Total Purchases					
39	- GWh	6,058	5,768	4,650	7,245	6,762
40	- $1,000	$456,843	$452,166	$373,528	$511,083	$472,238
41						
42						
43	**Power Sales**					
44	Wholesale Sales (Including MISO)					
45	- GWh	646	881	1,277	496	932
46	- $1,000	$37,832	$49,505	$75,163	$36,208	$66,202
47						
48						
49	**Net Purchased Power**					
50	- GWh	5,412	4,887	3,373	6,750	5,830
51	- $1,000	$419,010	$ 402,660	$ 298,365	$ 474,875	$ 406,036

Michigan Public Service Commission
The Detroit Edison Company
NOx Emission Allowance Projections Ozone Season
Years 2009 - 2013

Case No.: U-15677
Exhibit No.: A-18 (APW-5)
Page: 1 of 1
Witness: A.P. Wojtowicz

Line No.	(a)		(b) 2009	(c) 2010	(d) 2011	(e) 2012	(f) 2013
1							
2	Beginning Balance of Allowances	**Tons**	**2,138**	**1,766**	**1,858**	**1,811**	**1,634**
3							
4	DECo Annual Allocation From EPA (Excluding MPPA)	**Tons**	**14,646**	**14,027**	**14,027**	**13,881**	**13,881**
5							
6	Purchases committed to in 2009	Tons	2,638	4,646	4,033	1,231	
7	Purchases committed to in 2010	Tons				1,055	1,087
8	Purchases committed to in 2011	Tons					1,058
9	Purchase of Allowances	**Tons**	**2,638**	**4,646**	**4,033**	**2,286**	**2,145**
10							
11	Total Allowances Available	**Tons**	**19,422**	**20,439**	**19,918**	**17,978**	**17,661**
12							
13	Expected Allowances to be Consumed	**Tons**	(17,656)	(18,581)	(18,108)	(16,343)	(16,055)
14							
15	Ending Balance	**Tons**	1,766	1,858	1,811	1,634	1,606
16							
17							
18	Beginning Balance of Allowances	**$**	$ 1,661,886	$ 536,502	$ 382,844	$ 362,577	$ 229,956
19							
20	DECo Annual Allocation From EPA (Excluding MPPA)	**$**					
21							
22	Purchase of Allowances	**$**	$ 2,025,984	$ 3,674,984	$ 3,605,699	$ 2,167,078	$ 2,041,731
23							
24	Total Allowances Available	**$**	$ 3,687,870	$ 4,211,486	$ 3,988,543	$ 2,529,655	$ 2,271,687
25							
26	Expected Allowances to be Consumed	**$**	$ (3,151,368)	$ (3,828,642)	$ (3,625,966)	$ (2,299,699)	$ (2,065,182)
27							
28	Ending Balance Current NOx Allowances Asset Account	**$**	$ 536,502	$ 382,844	$ 362,577	$ 229,956	$ 206,506
29							
30							
31	DECo Annual Allocation From EPA (Excluding MPPA)	**$/Ton**	$ -	$ -	$ -	$ -	$ -
32	Purchase of Allowances	**$/Ton**	$ 768	$ 791	$ 894	$ 948	$ 952
33							
34	Total Average Cost of Available Allowances	**$/Ton**	$ 304	$ 206	$ 200	$ 141	$ 129

Michigan Public Service Commission
The Detroit Edison Company
NOx Emission Allowance Projections Annual
Years 2009 - 2013

Case No.: U-15677
Exhibit No.: A-19 (APW-6)
Page: 1 of 1
Witness: A.P. Wojtowicz

Line No.	(a)		(b) 2009	(c) 2010	(d) 2011	(e) 2012	(f) 2013
1							
2	Beginning Balance of Allowances	**Tons**	**2,653**	**4,291**	**4,232**	**4,174**	**3,975**
3							
4	DECo Annual Allocation From EPA (Excluding MPPA)	**Tons**	**31,479**	**31,479**	**31,479**	**31,281**	**31,281**
5							
6	Allowances purchased before respective vintage year	Tons	2,150	1,750	1,250		
7	Purchases committed to in 2009	Tons	10,916	9,027	8,953	4,234	
8	Purchases committed to in 2010	Tons				4,035	3,540
9	Purchases committed to in 2011	Tons					3,402
10	Purchase of Allowances	**Tons**	**13,066**	**10,777**	**10,203**	**8,270**	**6,942**
11							
12	Total Allowances Available	**Tons**	**47,198**	**46,547**	**45,914**	**43,725**	**42,198**
13							
14	Expected Allowances to be Consumed	**Tons**	(42,907)	(42,315)	(41,740)	(39,750)	(38,362)
15							
16	Ending Balance	**Tons**	4,291	4,232	4,174	3,975	3,836
17							
18							
19	Beginning Balance of Allowances	**$**	$ 9,359,550	$ 9,187,026	$ 3,716,232	$ 2,920,656	$ 2,513,053
20							
21	DECo Annual Allocation From EPA (Excluding MPPA)	**$**					
22							
23	Purchase of Allowances	**$**	$ 48,274,122	$ 31,692,809	$ 28,411,996	$ 24,723,846	$ 20,759,408
24							
25	Total Allowances Available	**$**	$ 57,633,672	$ 40,879,835	$ 32,128,229	$ 27,644,501	$ 23,272,461
26							
27	Expected Allowances to be Consumed	**$**	$ (48,446,646)	$ (37,163,603)	$ (29,207,573)	$ (25,131,448)	$ (21,156,856)
28							
29	Ending Balance Current NOx Allowances Asset Account	**$**	$ 9,187,026	$ 3,716,232	$ 2,920,656	$ 2,513,053	$ 2,115,605
30							
31							
32	DECo Annual Allocation From EPA (Excluding MPPA)	**$/Ton**	$ -	$ -	$ -	$ -	$ -
33	Purchase of Allowances	**$/Ton**	$ 3,695	$ 2,941	$ 2,785	$ 2,990	$ 2,990
34							
35	Total Average Cost of Available Allowances	**$/Ton**	$ 2,141	$ 878	$ 700	$ 632	$ 551

Michigan Public Service Commission
The Detroit Edison Company
Incremental SO2 Emission Allowance Projections
Years 2009 - 2013

Case No.: U-15677
Exhibit No.: A-20 (APW-7)
Page: 1 of 1
Witness: A.P. Wojtowicz

Line No.	(a)		(b) 2009	(c) 2010	(d) 2011	(e) 2012	(f) 2013
1							
2	Beginning Balance of Allowances	**Tons**	109,469	179,611	255,626	155,269	92,016
3							
4	DECo Annual Allocation From EPA (Excluding MPPA)	**Tons**	224,288	204,445	204,445	204,445	204,445
5							
6	Allowances Purchased before respective vintage year	**Tons**				17,000	12,500
7	Purchase of Allowances	**Tons**					
8	Swaps / Loans	**Tons**	25,926	42	-	68	-
9							
10	Total Available Allowance	**Tons**	359,683	563,710	460,071	376,782	308,961
11							
12	Expected Allowances to be Consumed	**Tons**	(180,072)	(308,084)	(304,802)	(284,766)	(183,668)
13							
14	Ending Balance	**Tons**	179,611	255,626	155,269	92,016	125,293
15							
16							
17	Beginning Balance of Allowances	**$**	$ 6,549,556	$ 3,282,698	$ 1,488,607	$ 502,389	$ 1,267,623
18							
19	DECo Annual Allocation From EPA (Excluding MPPA)	**$**					
20							
21	Allowances Purchased before respective vintage year	**$**				$ 4,688,210	$ 3,929,875
22	Purchase of Allowances	**$**					
23	Swaps / Loans	**$**	$ 24,252				
24							
25	Total Available Allowance	**$**	$ 6,573,808	$ 3,282,698	$ 1,488,607	$ 5,190,599	$ 5,197,498
26							
27	Expected Allowances to be Consumed	**$**	$ (3,291,109)	$ (1,794,091)	$ (986,219)	$ (3,922,976)	$ (3,089,757)
28							
29	Ending Balance Current SO2 Allowances Asset Account	**$**	$ 3,282,698	$ 1,488,607	$ 502,389	$ 1,267,623	$ 2,107,740
30							
31							
32	DECo Annual Allocation From EPA (Excluding Belle River)	**$/Ton**	$ -	$ -	$ -	$ -	$ -
33	Allowances Purchased before respective vintage year	**$/Ton**	$ -	$ -	$ -	$ 276	$ 314
34	Purchase of Allowances	**$/Ton**	$ -	$ -	$ -	$ -	$ -
35	Swaps / Loans	**$/Ton**	$ 1	$ -	$ -	$ -	$ -
36							
37	Total Average Cost of Available Allowances	**$/Ton**	$ 18	$ 6	$ 3	$ 14	$ 17
38							
39							
40	Expected Allowances to be Consumed	**$**	$ (3,291,109)	$ (1,794,091)	$ (986,219)	$ (3,922,976)	$ (3,089,757)
41	Allowances in Base Rates	**$**	$ 716,258	$ 716,258	$ 716,258	$ 716,258	$ 716,258
42	Incremental SO2 Allowance Expense	**$**	$ (2,574,851)	$ (1,077,833)	$ (269,961)	$ (3,206,718)	$ (2,373,499)

Michigan Public Service Commission
The Detroit Edison Company
Urea Cost Projection
Years 2009 - 2013

Case No.: U-15677
Exhibit No.: A-21 (APW-8)
Page: 1 of 1
Witness: A.P. Wojtowicz

Line No.	(a)		(b) 2009	(c) 2010	(d) 2011	(e) 2012	(f) 2013
1							
2	Cost of Delivered Liquid Urea (70% concentrate)	**$/Ton**	235	244	249	252	265
3	Cost of Urea per ton of NO_x removal	**$/Ton**	219	228	232	235	247
4	NO_x Removal at Monroe Units 1, 3, & 4	**Tons**	30,443	33,256	33,044	28,787	30,702
5	Ureas cost	**$**	$ 6,669,170	$ 7,570,905	$ 7,669,406	$ 6,759,656	$ 7,582,352

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 2009 Metered Jurisdictional Sales of Electricity	))))))	Case No. U-15677

QUALIFICATIONS

AND

DIRECT TESTIMONY

OF

JAMES BRUNELL

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF JAMES A. BRUNELL

Line No.

Q. Please state your name and business address.

A. My name is James A. Brunell. My business address is The Detroit Edison Company, 2000 Second Avenue, Detroit, Michigan 48226.

Q. What is your position and on whose behalf are you testifying?

A. I am a Consultant in Regulatory Affairs and am providing this testimony on behalf of the Detroit Edison Company ("Company" or "Detroit Edison").

Q. What is your educational background?

A. I received a Bachelor of Arts degree with a major in economics from the University of Massachusetts in 1992, and a Masters in Business Administration from Michigan State University in 1999.

Q. Please review your employment history with Detroit Edison.

A. I began my career at Detroit Edison in 2000 as a Sr. Regulatory Strategist in the Regulatory Policy and Operations Department. For the last several years I have been a Consultant in the Federal Regulatory group, which is a group within the Regulatory Policy and Operations department.

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

A. Yes, I completed the American Gas Association's Gas Rates Course in May of 2008.

Line No.

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

A. I have been responsible for representing the interests of the Company in transmission rate design proceedings before FERC, including ER05-6 (Seams Elimination Charge Adjustment and pricing of economic transmission expansions between MISO and PJM), EL05-121(PJM Rate design), ER07-1233 (MISO rate design). I also participate in the Edison Electric Institute's Market Based Rates and Affiliate Restrictions working groups.

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

A. Yes, I sponsored testimony in MPSC case No. U-15417, Detroit Edison's 2008 PSCR Plan.

Line No.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide an overview of Detroit Edison's activities that pertain to the cost and quality of transmission service received by the Company's PSCR customers under the Midwest Independent Transmission System Operator, Inc.'s ("MISO") transmission tariff.

Q. What specific federal regulatory issues are you addressing in your testimony?

A. There are four issues that I will discuss in my testimony that may affect Detroit Edison's customers during the 2009 through 2013 PSCR forecast period. They are:

- Pricing of Economic Transmission Expansions Between MISO and PJM
- The North American Electric Reliability Corporation's Proposed Change in Registry Criteria.
- MISO's Transmission Expansion Plans (MTEP)
- FERC's Notice of Inquiry ("NOI") regarding the methodology used to assess its annual electric charges.

Q. Are you sponsoring any Exhibits?

A. No.

Line No.

Pricing of Economic Transmission Expansions Between MISO and PJM

Q. How are economic transmission expansions between MISO and PJM currently priced?

A. Currently there is no protocol for pricing economic transmission expansions between MISO and PJM.

Q. Why is a pricing policy for economic transmission expansions between MISO and PJM required?

A. On November 21, 2005 FERC issued an order in FERC docket No. ER05-6-023 that accepted proposed modifications in the MISO-PJM Joint Operating Agreement (JOA). In this order, FERC ordered the two Regional Transmission Organizations (RTOs), and their respective transmission owners, to submit a proposal detailing a methodology for allocating the costs of cross-border economic projects. This proposal is currently due to be filed with FERC no later than January 28, 2009.

Q. The original directive to address cross-border economic expansion cost allocations was issued in 2005, but a proposal will not be submitted until 2009. Why has the process taken so long?

A. Today, each RTO has its own methodology for allocating the costs of economic transmission expansions, and there are significant differences between the two approaches. Although each RTO attempts to calculate the savings from a transmission expansion as the sum of the reduction in generation costs and energy prices, there are differences in the methods of calculation. For example, PJM nets

Line No.

the benefits of existing financial transmission rights from the project benefits. MISO's methodology does not include this adjustment. The two RTOs employ different time horizons for the financial analyses, ten years for MISO and fifteen years for PJM. The RTOs also use different benefit to cost ratios for determining whether or not a project is eligible for cost sharing; MISO uses a range of 1.2 – 3.0, and PJM uses a constant ratio of 1.25.

These specifics are critically important to stakeholders because it is possible that the cost of multi-billion dollar projects could be allocated via the final methodology. As MISO noted in a recent filing to FERC, the issue of cost allocation is one of the most divisive topics discussed by stakeholders[1]. MISO has noted that this issue is so important to stakeholders that it may drive RTO membership decisions[2]. Detroit Edison is, of course, vitally interested in achieving overall transmission cost and cost allocation fairness for itself and its customers.

Q. What progress has been made towards developing a cross border pricing proposal for economic transmission expansions?

A. The RTOs held stakeholder meetings on May 19, 2008, June 16, 2008, July 24, 2008, August 27, 2008, and September 24, 2008. Detroit Edison has offered its thoughts and concerns in each of the meetings. These meetings have focused on how best to define and evaluate the benefits of a proposed cross border economic

[1] Informational Compliance Filing of the Midwest Transmission System Operator, Inc. FERC docket No. ER06-18-03, pg. 3.
[2] Id., pg. 4.

Line No.

expansion project[3].

Q. What future steps are envisioned in the development of the cross border pricing proposal?

A. The RTOs plan to develop a threshold test to determine which projects are eligible for cost sharing. When a general consensus is achieved on this metric, the RTOs plan to develop the cost allocation methodology to equitably share the costs of proposed projects between the two RTOs[4]. The next meeting to discuss the process is scheduled for October 21, 2008.

Q. Why is the proposal for pricing economic transmission expansions important to Detroit Edison and its customers?

A. As noted, *supra*, there is the possibility that the costs of multi-billion dollar transmission expansion projects will be allocated pursuant to this policy. Since Detroit Edison's service territory is not electrically remote from portions of the MISO-PJM border, it is possible that the cost of large projects allocated according to the methodology chosen in this docket could have material rate effects for the Company's PSCR customers.

Q. What has the Company's position been with respect to allocating costs for economic transmission expansions?

A. In recent comments, submitted by the Company to FERC regarding MISO's filing

[3] Motion for Extension of Time [to] Submit Compliance Filing of PJM Interconnection, L.L.C. and the Midwest Independent Transmission System Operator, Inc., July 15, 2008, pg. 4. Docket No. ER05-6-044.
[4] Id, pg. 5.

Line No.

addressing cost allocations (Docket No. ER06-18-013), the Company advocated the position that stakeholders should only be asked to pay for transmission expansions from which they actually benefit. Additionally, the benefits that are used as the justification for such projects must be legitimate and measureable.

The North American Electric Reliability Corporation's Proposed Change in Registry Criteria.

Q. What is the North American Reliability Corporation's (NERC) *Statement of Registry Criteria*?

A. The NERC *Statement of Registry Criteria* is the set of criteria used by NERC to determine what roles entities perform with respect to the bulk power grid. Specifically, NERC uses these criteria to determine which entities will be registered as "owners", "operators" or "users" of the bulk power system. Once an entity, such as Detroit Edison, is registered as a certain function, it is responsible for compliance with all of the reliability standards assigned to that function.

Q. Have there been any proposed changes to the criteria in that Statement?

A. Yes, in accordance with FERC's December 20, 2007 Order[5], on July 31, 2008 NERC filed a proposal with FERC to change the registry criteria that specifies which entities are Load Serving Entities (LSE). NERC's proposal changes the definition of LSE *from* those entities that supply electricity to end use customers

[5] 121 FERC 61,247.

(e.g. retail electric suppliers (RES)), *to* the Distribution Provider (DP) to whose system the load is connected.

Q. Why did NERC make this proposal?

A. NERC made this proposal as a result of FERC's December 20, 2007 Order. In 2007, several RESs appealed their NERC registrations as LSEs to FERC. In its December 20, 2007 order, FERC granted the LSEs' appeal, and directed NERC to submit a plan detailing how it would address any reliability gaps created by the repeal of the RESs' LSE registrations. On March 4, 2008, NERC submitted a plan to FERC addressing the identified reliability gap. In the short term, NERC indicated that it would create a registration category for "Non-Asset Owning LSEs"[6], and in the long term it will address the changes needed in the reliability standards to account for the load previously served by RESs.

Q. Did NERC follow the approach it detailed in its March 4, 2008 filing with FERC?

A. No, it changed its approach to solving the reliability gap in the short term. Instead of creating a subset of the LSE designation to account for the fact that some RESs do not own any assets, it instead decided to change the LSE registry criteria to require the DP to be the LSE for all load connected to its system.

[6] Order on Compliance Filing, April 4, 2008, pg. 2. Docket No. RC07-4.

Line No.

Q. Does the Company agree with the new approach taken by NERC?

A. No, the Company does not agree with this new approach. As a result, Detroit Edison filed comments with the FERC on September 2, 2008 detailing what it believes to be the major flaw in this approach.

As the DP, Detroit Edison is responsible for reporting information to the ISOs regarding all demand response activities within its footprint. However, it will not have complete information regarding the demand response activities of all RESs which serve load in its service territory. Detroit Edison cannot supply demand response activity data to which it does not have access. Without access to this information, the entities charged with reliability of the electric grid could have an incomplete set of information for ascertaining the current state, and for modeling the future needs, of the bulk electric system. In its comments to FERC, Detroit Edison suggested that instead of arbitrarily assigning all of the LSE reliability responsibilities to the DP, NERC should instead "logically [assign] the necessary standards and requirements to the appropriate registered entities."[7]

Q. Why is this issue important to the Company?

A. If all of the LSE requirements are assigned to the DP, then the Company, as the DP, will be performing functions for RESs, but will not be compensated for these tasks. Additionally, the only way to ensure that there are no reliability gaps is for

[7] Comments of The Detroit Edison Company, Docket No. RC07-4-003, pg. 3.

Line No.

NERC to assign responsibility for reliability standards to the appropriate registered entities.

MISO's Transmission Expansion Plans (MTEP)

Q. What has been the effect of FERC's issuance of its Order 890 on the MISO transmission planning process?

A. In February 2007, FERC issued the Final Rule on Preventing Undue Discrimination and Preference in Transmission Service (Order 890) requiring, in part, that each transmission provider's planning process meet the FERC's nine planning principles established to ensure an open and transparent transmission planning process.

In December 2007 MISO submitted a revision to Attachment FF of its tariff[8], which details its compliance with FERC's Order 890. In its Attachment FF revision, MISO describes how stakeholders will be able to participate in the transmission planning process. In addition to the tariff revisions, MISO has created a Transmission Planning Business Practice Manual, which is posted to its website.

Stakeholders have been provided with an enhanced ability to participate in the planning process, specifically through MISO's formation and scheduling of Sub-Regional Planning Meetings (SPMs). These meetings now initiate MISO's planning cycle and are open to any parties interested in, or affected by, the planning process.

[8] Conditionally accepted by FERC on May 15, 2008 in Docket No. OA08-53.

Line No.

The purpose of these meetings is to provide the opportunity for the transmission planners to present proposed projects, describe the need for those proposed projects, and provide the modeling assumptions justifying the need for the proposed projects. The SPMs are intended to provide a forum for stakeholders to review, and provide input to, the planning models and assumptions, although there is nothing at present that requires MISO or its transmission owning members to address the concerns voiced by participants. They also provide a forum in which to discuss alternative assumptions and planning criteria and also provide for the opportunity to offer alternative solutions to proposed projects. The exchange of information, as is required by the tenets of Attachment FF, is a key element of successful transmission planning.

Q. Has MISO taken on any new role or responsibility with regard to local transmission planning?

A. Yes. A major feature of compliance with Order 890 by the transmission owners within MISO is that, with the exception of the American Transmission Company, all other transmission owners have elected to comply with Order 890 by having MISO integrate the transmission owner's local planning process within MISO's regional planning process. This integration is detailed in Attachment FF to MISO's tariff and effectively has MISO now performing the role of local transmission planner with input from the transmission owners and affected stakeholders. MISO has a requirement to ensure that the Order 890 principles of openness and transparency are being adhered to as part of the process of evaluating projects, prior to their

Line No.

submittal to MISO's Board of Directors for approval.

Q. Did MISO convene Sub-Regional Planning meetings in 2008?

A. Yes. MISO held a series of SPMs in its East, Central and Western Planning Regions. Detroit Edison resides in MISO's East Planning Region and there were two such meetings held, the first in Livonia on January 22, 2008 and the second in Akron on June 25, 2008. In addition, MISO held two additional meetings, specifically addressing projects in Michigan's Lower Peninsula. The Michigan Sub-Regional Technical Task Force meetings were held in the offices of Detroit Edison on April 8, 2008 and in the offices of Consumers Energy on June 2, 2008. Detroit Edison has been actively engaged in these meetings and in subsequent review of the projects being proposed by ITC*Transmission* (ITC) and evaluated by MISO within the current planning cycle (MTEP08).

Q. Please summarize the projects proposed to be built by ITC*Transmisison* as they are listed in MISO's MTEP report.

A. For MTEP08, as reported in the August 21, 2008 draft report, ITC has proposed, and MISO is evaluating, for inclusion in Appendix A, which list the projects approved for construction, the following project types:

Line No.

Project Type	Number of Projects	Forecasted Amount
Generator Interconnection	2	$10.2M
Reliability	2	$ 6.0M
Other (includes customer interconnection and maintenance projects)	9	$23.1M

This compares to the following projects proposed and evaluated during the MTEP07 planning cycle:

Project Type	Number of Projects	Forecasted Amount
Generator Interconnection	0	$ 0
Reliability	2	$237.4M
Other (includes customer interconnection and maintenance projects)	9	$ 32.6M

Q. Why is the Company's involvement in the transmission planning process important?

A. The Company's involvement in the transmission planning process is important because the Company provides needed inputs to the process, such as load forecasts, and the Company is also able to offer alternatives to proposed transmission expansions that may result in a lower cost to its customers.

Line No.

FERC Annual Assessment

Q. On April 21, 2008 the FERC issued a NOI in Docket No. AD08-7 seeking comment on whether the methodology FERC currently uses to assess electric annual charges, the method through which FERC's operating expenses are recovered, is fair and equitable. Did the Company file comments in response to this NOI?

A. Yes, the Company filed comments on May 28, 2008, which stated that the current methodology used by FERC to assess charges is not fair and equitable.

Q. What was the basis for the Company's comments?

A. The Company's comments are based upon the Company's belief that there is a disparity as to how charges are assessed to utilities based on RTO membership. Utilities within RTOs are essentially assessed charges based on their total bundled load, while utilities that are not in RTOs are only assessed FERC charges based on the unbundled portion of their transmission service, which by definition excludes their bundled load. The result of this methodology leads to utilities within RTOs paying significantly higher FERC assessments than non-RTO participants, even though a utility's contribution to FERC's workload is nearly identical, regardless of RTO participation. The Company's comments in this docket highlighted this result, noting that it is grossly discriminatory and inequitable[9].

[9] Comments of The Detroit Edison Company, pg. 2, Docket AD08-7.

Line No.

Q. Did the Company suggest an alternative methodology for allocating FERC's charges?

A. Yes, the Company suggested that FERC's assessment be allocated based upon the total annual load of all jurisdictional public utilities that provide transmission service. If the FERC adopts this methodology, the Company's FERC assessment will be reduced.

Q. Why is the FERC annual assessment important to PSCR customers??

A. As detailed by Mr. Shields, the FERC annual assessment is Schedule 10A, one of the charges included in the Company's transmission bill.

Q. What is the current status of this matter?

A. This issue is awaiting additional action by the FERC.

Q. Does this conclude your testimony?

A. Yes.

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 2009 Metered Jurisdictional Sales Of Electricity.	)))))))	Case No. U-15677 (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, 2008, a copy of The Detroit Edison Company's 2009 PSCR Plan Application, proposed Notice of Hearing, and Testimony and Exhibits of Ms. Sherrie L. Siefman and Angela P. Wojtowicz and Messrs. Robert A. Gailliez, James D. Good, Kenneth D. Johnston, and Michael W. Shields and Testimony of James A. Brunell 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
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Date: 2008.09.30 16:09:09 -04'00'

Estella R. Branson

Subscribed and sworn to before
me this 30th day of September, 2008

Karyn Beth Teal

Digitally signed by Karyn Beth Teal
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Notary Public

MPSC Case No. U-15677
September 30, 2008
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