

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Commission's own motion)
ordering **THE DETROIT EDISON COMPANY**)
to show cause why its retail rates for the sale)
and distribution of electric energy should not)
be decreased.)

Case No. U-14838

QUALIFICATIONS
AND
DIRECT TESTIMONY
OF
MICHAEL W. SHIELDS

THE DETROIT EDISON COMPANY
QUALIFICATIONS OF MICHAEL W. SHIELDS

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

3 A. My name is Michael W. Shields. My business address is 2000 Second
4 Avenue, Detroit, Michigan 48226.

5

6 **Q. Would you please describe your educational background?**

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

10

11 **Q. What is your current position at Detroit Edison?**

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

13

14 **Q. Would you please describe your professional experience?**

15 A. Following graduation from North Carolina State University in the spring of
16 1973, I was employed by Carolina Power & Light Company during the pre-
17 operational and power ascension testing programs for the Brunswick 1 & 2
18 nuclear units in Southport, North Carolina. Following the completion of the
19 startup testing programs, I served as a plant reactor engineer, responsible
20 for providing technical support to the operations staff for reactor startups
21 and nuclear core testing and operations.

22

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

Line
No.

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

5

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

16

17 In 1996 the Resource Planning group was merged with the Customer
18 Energy Solutions -- Sourcing (Formerly Power Supply Transactions -
19 Operations) function. In the Sourcing group, my primary responsibility
20 continued to involve the development of long-term fuel and resource
21 planning projections using computer simulation models. Such studies
22 evaluated long-term power purchases or sales, requests for proposals, and
23 long-term marginal costs. I also continued to be responsible for studies in
24 support of the Company's long-term sulfur dioxide (SO₂) compliance
25 planning.

Line
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1

2 In 1999 the Customer Energy Solutions – Sourcing function became part of
3 the Generation Optimization group. In addition to the other responsibilities
4 referenced above, I also became involved with planning for and procuring
5 the Company's summer capacity needs.

6

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

13

14 In my current position I am working directly with MISO in support of Detroit
15 Edison's participation in the MISO Energy Market. This includes:
16 coordinating the Market Participant registration process; completing and
17 updating the registration of all the Detroit Edison assets as part of the MISO
18 Asset registration process; and handling the Financial Transmission Rights
19 (FTR) registration and management processes necessary for Detroit Edison
20 to obtain FTRs to protect against high congestion costs in the MISO
21 markets. I also work with other groups in the Company in developing
22 bidding strategies for the MISO market, supporting market settlement
23 issues, and overall in coordinating the Company's involvement with all types
24 of MISO-related activities.

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1 I have participated on many of the MISO stakeholder committees,
2 subgroups, and working groups and have also attended numerous
3 Merchant-related MISO training sessions which are intended to familiarize
4 people with the MISO Energy Market.

5

6 **Q. Are you a registered professional engineer?**

7 A. Yes, I qualified as a Professional Engineer by examination in the State of
8 North Carolina.

9

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

11 A. Yes. My most recent experience was sponsoring testimony in the 2006
12 Power Supply Cost Recovery (PSCR) Plan Case No. U-14702 and in
13 sponsoring testimony in the 2005 PSCR Reconciliation Case No. U-14275-
14 R. I also sponsored testimony in the 2005 PSCR Plan Case No. U-14275,
15 the 2000 PSCR Plan Case No. U-12121 and in the Company's 1997 PSCR
16 Plan Case No. U-11175.

THE DETROIT EDISON COMPANY
DIRECT TESTIMONY OF MICHAEL W. SHIELDS

Line
No.

1 **Q. What is the purpose of your testimony?**

2 A. The primary purpose of my testimony is to present Detroit Edison's projected
3 expenses associated with being a network transmission customer of the
4 International Transmission Company (ITC) and with being a Market
5 Participant of the Midwest Independent Transmission System Operator
6 (MISO). Many of the MISO charges I will discuss began with the start of the
7 MISO Energy Market on April 1, 2005.

8

9 All of these MISO/transmission expenses are required in order for Detroit
10 Edison to serve the anticipated full service customer load requirements from
11 the MISO Energy Market. My testimony will address the actual expenses for
12 2005 and the projected expenses for the period 2006 through 2011. I am
13 dividing my testimony covering these expenses into two sections. The first
14 section discusses the transmission and MISO related charges for Detroit
15 Edison that are unrelated to the MISO Energy Market. The second section
16 discusses the additional charges associated with participation in the MISO
17 Energy Market. Along with my discussion of the various charges associated
18 with the Company's participation in the MISO Energy Market, I will also
19 address the Company's proposed cancellation of its Optional Retail Access
20 Backup Service Tariff, EC-3.

21

22 In addition to supporting the transmission and MISO-related expenses, I am
23 also including testimony to support the need for the Company to enter into
24 "multi-summer" agreements with third party generation owners to better
25 ensure that Detroit Edison will have adequate capacity to cover any future

Line
No.

1 summer capacity needs. This relates to a recent decision by MISO not to
2 implement a capacity market.

3

4 **Q. Are you supporting any Exhibits?**

5 A. I prepared and am supporting the following Exhibits:

6 Exhibit DE-16

7 Schedule F7-4 Transmission Expense for Years 2005-2011

8 Schedule F7-5 MISO Energy Market Settlement Statement

9 Charges/Credits

10 Schedule F7-6 MISO Settlement Statement Charges/Credits

11 Projections for 2006-2011

12 Exhibit DE-13

13 Schedule E-9 Optional Retail Access Backup Service Tariff, EC-3

14

15 **Q. Mr. Shields, has the Commission previously approved the recovery of**
16 **transmission expenses as part of the recovery of power supply**
17 **expenses?**

18 A. Yes. Detroit Edison properly includes transmission expense in the PSCR
19 pursuant to the Commission's November 23, 2004 Order in Case No. U-
20 13808. The Commission again approved the inclusion of transmission and
21 MISO-related costs in Detroit Edison's PSCR process in its September 20,
22 2005 order in Case No. U-14275 (Detroit Edison's 2005 PSCR Plan case).

23

24 **Q. What is the purpose of Exhibit DE-16, Schedule F7-4?**

25 A. Exhibit DE-16, Schedule F7-4 presents the Company's actual 2005 and the

Line
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1 projected 2006 through 2011 network transmission expense items and
2 MISO Energy Market Cost items. Schedules 1, 2, 3, 5, 6, 9, 10, 10-FERC,
3 16, 17, 18, 22, 24, 25 and 26 are transmission and ancillary service
4 schedules for transmission service under the MISO Transmission and
5 Energy Market Tariff (TEMT) as filed with FERC. Schedule 2 is an Open
6 Access Transmission Tariff (OATT) associated with Reactive Power,
7 although only the cost impacts of this schedule associated with the
8 Independent Power Producers (IPPs) are included in my exhibit. Later in
9 my testimony I will discuss these schedules and the other MISO Energy
10 Market Cost items in greater detail.

11

12 **Q. What is the purpose of Exhibit DE-16, Schedule F7-5?**

13 A. The line items on this Exhibit reflect the actual line items included on a
14 typical MISO Settlement Statement associated with the MISO Energy
15 Market charge types. As a MISO network customer and Market Participant,
16 each of these MISO charge types represent non-bypassable charges to
17 Detroit Edison. The Company is required to purchase each of these
18 services from MISO and/or pay its share of any uplift/participation costs
19 related to the MISO Energy Market.

20

21 **Q. What is the purpose of Exhibit DE-16, Schedule F7-6?**

22 A. Exhibit DE-16, Schedule F7-6 reflects the projections of the more significant
23 MISO Energy Market related charges/credits that will apply for 2007. Later
24 in my testimony I will discuss how these charges/credits were derived
25 through the use of data available from the first 12 months of the MISO

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1 Energy Market.

2

3 **Q. What is the purpose of Exhibit DE-13, Schedule E-9?**

4 A. Exhibit DE-13, Schedule E9 presents the Company's Optional Retail
5 Access Backup Tariff EC-3 which has been rendered obsolete as a result of
6 the start of the MISO Energy Market.

7

8 **SECTION 1 – TRANSMISSION SERVICE COSTS & MISO ENERGY MARKET**
9 **CHARGES**

10

11 **Q. What is the network transmission Schedule 1 expense shown on line 3**
12 **of Exhibit DE-16, Schedule F7-4?**

13 A. Schedule 1 is the MISO ancillary service for scheduling, system control and
14 dispatch service provided by MISO as the transmission provider. This
15 service is required to schedule the movement of power through, out of,
16 within or into a control area and must be purchased by the transmission
17 customer (in this case Detroit Edison) from MISO. The monthly charge for
18 Schedule 1 is the monthly peak demand multiplied by the FERC approved
19 rate, currently \$53.297/MW-Month. This schedule will result in
20 approximately \$5.4 million of expense in 2007.

21

22 **Q. What is the network transmission Schedule 9 expense shown on line 4**
23 **of Exhibit DE-16, Schedule F7-4?**

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

Line
No.

1 zonal rate defined in the MISO tariff for the zone based upon where the load
2 is physically located, which in our case is the International Transmission
3 Company, zone 7. The ITC Schedule 9 rates are determined annually
4 based on a calculation using the actual ITC costs and capital expenditures,
5 as defined by Attachment O of the MISO tariffs. It should be noted that a
6 small portion of the Schedule 9 rate paid by Detroit Edison goes to The
7 Michigan Public Power Agency, as a result of their ownership of a small
8 amount of transmission located in the ITC footprint.

9

10 The current rate for Schedule 9, which is in effect from June 1, 2005 to May
11 31, 2006 is \$1,609/MW-month. This rate is projected to increase to
12 \$1,767/MW-month for the period June 1, 2006 to May 31, 2007. This rate is
13 modified each June. Because it is difficult to predict how this rate will
14 change given all the various parameters that can influence the rate
15 calculation, I am assuming that this rate will escalate at a modest 2% each
16 year starting in June 2007. It is very likely this rate will increase over the
17 next few years based on ITC's projected expenditures. This rate applied to
18 the forecasted monthly peak demands will result in approximately \$182.0
19 million of expense to Detroit Edison to serve its bundled retail customers in
20 2007.

21

22 **Q. What is the MISO Schedule 10 expense shown on line 7 of Exhibit DE-16,**
23 **Schedule F7-4?**

24 A. MISO Schedule 10 expense is the cost recovery adder under which MISO
25 recovers its cost of operation other than the costs associated with operation

Line
No.

1 of the Financial Transmission Rights (FTR) Market (Schedule 16) and the
2 Energy Market (Schedule 17). There are two components in the calculation
3 of Schedule 10 expense; one component is based on monthly peak
4 demand, which represents about 80% of the total charge, and the other
5 component is tied to monthly energy usage which represents about 20% of
6 the total charge. The demand charge component is based on the product of
7 monthly peak demand, the hours in the month, and the calculated demand
8 component rate. The energy component is the product of the energy usage
9 each month and the calculated energy component rate. Because the 80%-
10 20% split is determined based on the MISO total footprint, the actual cost
11 split for Detroit Edison may vary from 80% demand and 20% energy if the
12 average Detroit Edison load factor differs from the MISO load factor.

13

14 MISO has projected that the overall Schedule 10 rate for 2007 will be
15 \$0.144/MWh, which calculation is based on the total MISO monthly demand
16 and energy split. Using the Schedule 10 demand and energy rates projected
17 by MISO, the cost to Detroit Edison to participate in MISO to serve its retail
18 electric customers will be approximately \$10.0 million in 2007.

19

20 **Q. What is the MISO Schedule 10-FERC expense shown on line 10 of**
21 **Exhibit DE-16, Schedule F7-4?**

22 A. The MISO Schedule 10-FERC expense is the cost recovery adder for the
23 recovery by MISO of its FERC assessment fee. This fee is charged by
24 FERC to cover a portion of FERC's operating costs. This charge is also
25 sometimes referred to as the "FERC Assessment" charge. The charge to

Line
No.

1 MISO is based on total megawatt-hours of Transmission Service reported
2 each year by MISO on FERC Form 582.

3

4 MISO in turn allocates this cost to all MISO transmission customers,
5 including those taking network service, like the Company. The expense is
6 calculated by applying the MISO rate for this schedule to the monthly peak
7 demand multiplied by the hours in the month. Based on rate information
8 provided by MISO, for 2007 this assessment will be \$0.050 per MWh. For
9 2007, this charge represents a Detroit Edison expense of \$3.7 million.

10

11 **Q. What is the MISO Schedule 18 Expense shown on line 13 of Exhibit DE-**
12 **16, Schedule F7-4?**

13 A. MISO Schedule 18 represented a sub-regional rate adjustment established as
14 a result of a FERC settlement proceeding. In this proceeding it was agreed
15 that short-term payments would be made to the GridAmerica transmission
16 companies (First Energy, Northern Indiana Public Service (NIPS), and
17 Ameren) once they became transmission-owning members of MISO to
18 provide compensation for certain transmission revenues they believed they
19 would be foregoing by joining MISO. In 2005 the Company paid \$0.756
20 million per the settlement agreement. This charge terminated on September
21 30, 2005.

22

23 **Q. What is meant by the MISO Schedule 2 Adder Expense shown on line 16**
24 **of Exhibit DE-16, Schedule F7-4?**

25 A. Schedule 2 is the component of MISO's tariff intended to cover the costs from

Line
No.

1 compensating generators who provide Reactive Supply and Voltage Control
2 services. In past years Detroit Edison was the sole provider for this service in
3 the Detroit Edison service territory. Recently, FERC has specified that
4 Schedule 2 rates should be modified to also compensate IPPs that are
5 capable of providing these ancillary services within each control area.

6

7 A portion of the Schedule 2 adder rate is based on the revenues needed to
8 compensate the First Energy Solutions peakers located in Sumpter Township.
9 In addition, the Company is using the more current information available as to
10 the final charges for the reactive service being provided by the CMS Dearborn
11 Industrial Generation plant (DIG) (FERC Docket ER05-1497) and the DTE
12 East China generating units (FERC Docket ER06-348) as the applicable
13 filings have proceeded through the initial FERC review and settlement
14 process. A final order has yet to be issued by FERC in either of those
15 proceedings. However it is expected that these dockets will reach final
16 resolution in 2006 and for 2007 the projected cost associated with the
17 Schedule 2 adder for reactive supply and voltage control services for Detroit
18 Edison retail customers is about \$4.0 million.

19

20 **Q. What is the MISO Schedule 22 charge involving the Seams Elimination**
21 **Charge Adjustment (SECA) adder shown in line 19 of Exhibit DE-16,**
22 **Schedule F7-4?**

23 A. The Schedule 22 charge was proposed as a transition mechanism to
24 maintain revenues that certain Transmission Owners feel they are entitled to
25 after joining an RTO. By joining either the MISO Regional Transmission

Line
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1 Operator (RTO) or PJM RTO their revenue would otherwise drop,
2 particularly with the loss of the Regional Through and Out Rate (RTOR) for
3 transactions between PJM and the MISO. The Company has been actively
4 involved in the FERC Case, Docket No. ER05-6, addressing the rate
5 pancaking for transactions crossing RTO borders and is now involved in
6 working out final settlement agreements with the applicable SECA
7 companies. The impact of the settlement agreements on Detroit Edison's
8 PSCR customers will be addressed as part of the 2006 PSCR reconciliation
9 process.

10

11 As shown in Exhibit DE-16, Schedule F7-4, the Company paid
12 approximately \$16.1 million in SECA charges in 2005. For 2006 I am using
13 the information contained in the filed Schedule 22 tariff to estimate Detroit
14 Edison's cost at \$2.5 million, representing a rate of \$815,000/month that
15 was charged for January through March 2006. This charge terminated on
16 April 1, 2006.

17

18 **Q. What is the MISO Schedule 24 charge involving Balancing Authority**
19 **Charges shown in line 22 of Exhibit DE-16, Schedule F7-4?**

20 A. MISO has established a separate Schedule to collect the costs associated
21 with Balancing Authority (BA) Operations in the MISO region. The BA
22 applicable for Detroit Edison is the Michigan Electric Coordination System
23 (MECS) that is jointly operated by the ITC and Michigan Electric
24 Transmission Company (METC). It is my understanding this schedule will
25 be available for use to collect the MECS costs sometime during the summer

Line
No.

1 of 2006. However, it is also my understanding that there will be a reduction
2 in the MISO Schedule 1 rate that is currently being used to cover
3 scheduling, system control and dispatch services that will likely offset most,
4 if not all, of any added Schedule 24 charges. It is also possible the
5 transmission companies who operate MECS may chose to continue
6 collecting the MECS costs under the MISO Schedule 1 rate, in lieu of using
7 Schedule 24. Until we have more information on these charges, I am only
8 including this item as a placeholder and am not including any added costs
9 for Schedule 24 at this time.

10

11 **Q. What are the MISO Schedule 25 and Schedule 26 Network Upgrade**
12 **charges involving Transmission cost adders shown in line 25 of Exhibit**
13 **DE-16, Schedule F7-4?**

14 A. Over the past few months the MISO Regional Expansion Criteria and
15 Benefits (RECB) Task Force developed a cost allocation methodology to
16 allocate the cost of a new transmission line to not only the transmission
17 customer for whom the line is primarily being constructed, but also to
18 adjacent regions or zones that may also receive benefits from the new
19 transmission line. This proposal was approved by FERC in interim order
20 ER06-18 issued on February 3, 2006. In this order FERC approved a cost
21 sharing mechanism where a portion of the costs of any new transmission
22 project in MISO built at the 345 kV level and above that is approved by
23 MISO as being needed for system reliability would be uplifted to all load
24 serving entities on a MISO wide basis. While the order specified an initial
25 value of 20% of the project costs that should be uplifted in this manner on a

Line

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1 “postage stamp” basis, the final uplift value may be modified by FERC in its
2 final order in that the initial order was issued on a “subject-to-refund”
3 condition as FERC further investigates the appropriateness of the use of
4 20% as the postage stamp allocation percentage.

5

6 MISO will use Schedule 26 as the mechanism for collecting these charges.
7 Based on information provided by MISO, about \$1.1 billion of currently
8 identified 345 kV projects could be subject to the 20% postage stamp
9 allocation, leading to MISO system wide charges of about \$220 million.

10

11 Schedule 25 is also intended to uplift transmission costs on a postage
12 stamp basis in a manner similar to Schedule 26, but this schedule is
13 intended for use with large transmission projects built in another RTO region
14 that are determined to have benefits for load in MISO. The allocation of the
15 benefits of such a project much be mutually agreed upon by the regional
16 transmission planning organizations for the respective RTOs.

17

18 Given the uncertainty on the timing for the completion of the transmission
19 projects covered under Schedules 25 and 26, I have not included any costs
20 for 2007, but have made an estimate of the costs starting in 2008. These
21 cost estimates will be adjusted as more information becomes available.

22

23 **Q. What are the MISO Schedule 2, 3, 5, and 6 revenues shown in line 28 of**
24 **Exhibit DE-16, Schedule F7-4?**

25 A. Detroit Edison currently receives certain ancillary services revenues from

Line
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1 MISO associated with Schedule 2 (Reactive Supply and Voltage Control
2 from Generation Sources); Schedule 3 (Regulation and Frequency
3 Response); Schedule 5 (Operating Reserve – Spinning Reserve) and
4 Schedule 6 (Operating Reserve – Supplemental Reserve). These revenues
5 were previously excluded from the PSCR process. With the startup of a
6 MISO Ancillary Services market projected to occur sometime in 2007, it will
7 be more logical to include these revenues as part of the PSCR process.
8 The fuel and purchased power expense associated with providing these
9 ancillary services are already included within the PSCR.

10

11 I am including an estimate of a \$5 million credit (which I am proposing to be
12 applied in Detroit Edison's PSCR process) starting in 2007 to represent
13 these ancillary service revenues. This is only an estimate – it will be difficult
14 to know how competitive the Company can be in selling each of these
15 ancillary services in the future and what the market prices will be for these
16 services until we actually gain experience with the actual MISO Ancillary
17 Services market.

18

19 **Q. What is the Total Current Base Transmission cost shown in line 31 of**
20 **Exhibit DE-16, Schedule F7-4?**

21 A. The Total Base Transmission cost is the sum of Schedules 1, 2, 3, 5 6, 9,
22 10, 10-FERC, 18, the Schedule 2 Adder and the Schedule 24, 25, and 26
23 charges. For 2007 I estimate this cost to be approximately \$200.1 million.
24 This would be the Company's cost for MISO operations and transmission
25 expense absent a MISO Energy Market.

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2 **SECTION 2 - MISO ENERGY MARKET RELATED CHARGES & CREDITS**

3

4 **Q. Can you explain how Detroit Edison was affected by the start of the**
5 **MISO Energy Market?**

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

13

14 Each day, Detroit Edison “offers” its generating resources into the MISO
15 Energy Market and also “bids” to supply its projected load. In effect, Detroit
16 Edison purchases through the MISO Energy Market the energy needed to
17 serve its load at the market clearing LMP calculated for Detroit Edison’s
18 load. Likewise, energy from Detroit Edison generation resources is sold into
19 the MISO market at the LMP price calculated for each generator bus. MISO
20 determines which generators are the most economic to serve load within the
21 MISO Energy Market and provides start, stop, and dispatch information and
22 instructions for that generator.

23

24 **Q. What is an FTR?**

25 A. An FTR is a Financial Transmission Right. In the MISO Energy Market the

Line
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1 LMP pricing will reflect the cost of relieving any transmission congestion.
2 FTRs are financial instruments that give transmission customers such as
3 Detroit Edison the potential to protect against the costs associated with
4 transmission congestion.

5

6 The Company is allocated some level of FTRs as part of an annual MISO FTR
7 allocation process. The allocation amount may vary for each season, and for
8 the off-peak and on-peak periods. However, even after the FTR allocation
9 occurs, it is still likely that the Company could continue to be exposed to
10 congestion charges in the event of generating unit/transmission outages or
11 other events not captured in the allocation modeling. Additionally, in the
12 allocation process the Company has not historically received all of the FTRs it
13 has requested for each season.

14

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

23

24 Conceptually, a Financial Transmission Right is similar to a Physical
25 Transmission Right. Both are booked costs and are a necessary and integral

Line
No.

1 part of purchased and net interchange power transactions. Expenses for
2 FTRs are booked in account 555, Purchased Power.

3

4 **Q. What is the MISO Schedule 16 expense shown on line 35 of Exhibit DE-**
5 **16, Schedule F7-4?**

6 A. MISO Schedule 16 expense is the financial transmission rights (FTR)
7 administrative service cost recovery adder. The monthly expense is
8 calculated by multiplying the FTR Administrative Cost Recovery Adder rate
9 in effect at the time, by the total MW of FTR's held by the transmission
10 customer (in this case, Detroit Edison). According to MISO, the rate for
11 2007 is projected to be \$0.054/FTR-MWh, which is multiplied by the number
12 of hours in each month to get the monthly cost.

13

14 Assuming that the Company is able to obtain its full entitlement in the next
15 MISO FTR allocation, Detroit Edison anticipates that it will hold, at a
16 minimum, sufficient FTRs to cover its peak summer demand net of a
17 required adjustment for the Ludington Grandfathered Agreement (GFA).
18 This assumption would result in approximately \$5.1 million of Schedule 16
19 expense in 2007.

20

21 **Q. What is MISO Schedule 17 expense shown on line 38 of Exhibit DE-16,**
22 **Schedule F7-4?**

23 A. MISO Schedule 17 expense is the Energy Market Support Service Cost
24 Recovery Adder. This service will be provided by MISO to all transmission
25 customers and other MISO Market Participants that participate in

Line
No.

1 transactions using the transmission system or the day-ahead or real-time
2 energy markets. According to MISO, the expected Schedule 17 rate for
3 2007 will be \$0.081/MWh. This adder is applied to: 1) all MWh injected into
4 the transmission system by all system participants, including deliveries to
5 the transmission system from generation located both within the
6 transmission system and outside the transmission system, 2) all MWh
7 extracted from the transmission system by all system participants under
8 point-to-point or network integrated transmission service, including MWh
9 delivered to loads both within the transmission system and outside of the
10 transmission system, and 3) all physical and/or virtual bids or offers that
11 settle in the day-ahead market, but do not actually inject MWh into or extract
12 MWh from the transmission system in the real-time market. Detroit Edison's
13 portion of the Schedule 17 expense to cover MISO's costs associated with
14 the operation of the Energy Market is projected to be approximately \$8.6
15 million for 2007.

16

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

19 A. Other costs that will be incurred are: 1) FTR procurement costs, 2) Costs
20 (and credits) associated with the use of Marginal Loss Pricing in calculating
21 LMP costs paid by Load Serving Entities (LSEs), 3) Costs (and credits)
22 associated with Congestion costs for LSEs, and 4) Miscellaneous
23 uplift/participant charges and credits that MISO will be imposing on all
24 Market Participants under defined circumstances.

25

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

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

9

10 The FTR mechanism was established to help protect LSEs against their
11 exposure to the congestion cost component of LMP, thus lowering their
12 overall costs in the MISO Energy Market. Some FTRs are allocated to
13 MISO LSEs as part of an annual FTR allocation process. MISO Market
14 Participants can also procure FTRs during the MISO monthly and annual
15 auctions.

16

17 For 2006 and beyond I am projecting that there will be a need for Detroit
18 Edison to participate in the FTR auctions to protect against some of the
19 Company's exposure to congestion costs. FTR purchases may be useful, in
20 particular, to cover the energy flows associated with summer capacity
21 purchases, given that much of this capacity is typically procured from
22 sources outside of the ITC transmission zone.

23

24 I have developed an estimated average FTR cost value using actual MISO
25 auction clearing price data posted by MISO for the months of June, July,

Line
No.

1 and August of 2005. This estimate represents a capacity-weighted average
2 cost estimate of what an average cost might be in the future should a FTR
3 be purchased in the monthly FTR auctions from sources involving Michigan-
4 based IPP generators that could be used to serve Detroit Edison's summer
5 peak load. Most of these IPP generators have been contracted for in past
6 years by Detroit Edison to augment its summer capacity.

7

8 Based on this calculation, and making the assumption that Detroit Edison
9 would procure additional FTRs at this rate for about one third of its summer
10 capacity needs, I am projecting a cost of about \$1.1 million per year for FTR
11 procurement, as shown on line 41 of Exhibit DE-16, Schedule F7-4.

12

13 The actual costs of FTRs will be determined as part of the MISO competitive
14 FTR auction process, and could be higher or lower than the proxy value I
15 have selected as the basis for this cost estimate. On the other hand if, in
16 the future, Detroit Edison believes the projected congestion costs from a
17 particular source are not large enough to justify making FTR purchases, this
18 FTR money will not be spent. For this proceeding, I am trying to make a
19 reasonable estimate of what is likely to be spent on FTRs based on the
20 industry's limited knowledge and experience with FTRs.

21

22 **Q. Can you explain what is meant by MISO uplift/participant charges and**
23 **how they could impact the costs for the Company and its customers?**

24 A. MISO, by design, is intended to be "revenue-neutral" with regards to the
25 operation of the MISO Energy Market. To accomplish this revenue

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1 neutrality, MISO will ensure that all costs/credits for each hour are uplifted
2 among the appropriate Market Participants. Where MISO can pinpoint the
3 Market Participants that have caused additional costs to be imposed on the
4 market as a result of some action they have taken, these costs are uplifted
5 to that Market Participant. However, certain other charges/credits that occur
6 in the market are considered to result from the inherent structure of the
7 market itself, and these are typically uplifted by MISO to all Market
8 Participants on a load weighted basis. In particular, many of the charges
9 and credits associated with Grandfathered Agreements (GFAs) fall into this
10 category, as GFAs are given special treatment by MISO due to the historical
11 and long-term nature of these agreements.

12

13 On Exhibit DE-16, Schedule F7-5 and Exhibit DE-16, Schedule F7-6, I show
14 all the various charges/credits that are calculated by MISO. I will explain
15 some of the more significant charges/credits that are likely to be
16 experienced in 2007 based on current MISO Energy Market information.

17

18 **Q. Can you explain Exhibit DE-16, Schedule F7-5?**

19 A. Exhibit DE-16, Schedule F7-5 is in the format of an actual MISO Summary
20 Settlements Statement. It contains all the charge types directly related to
21 participation in the MISO Energy Market. MISO issues its first Settlements
22 Statement, including the estimated charges/credits for each item, seven
23 days after each operating day. MISO issues updated Settlement
24 Statements 14 days, 55 days, 105 days and currently 155 days and 395
25 days after each operating day, although the 155 day and 395 day updates

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1 will only continue for a few more months.

2

3 More information is available relative to the various charge types, how they
4 are calculated, and on the overall settlement process, in the "MISO
5 Business Practice Manual for Market Settlements" available on the
6 www.midwestiso.org web site under the "Documents" tab.

7

8 There are three categories of charge types and thirty-two individual items
9 represented in the settlement statement summary. The charge type
10 categories are the Day-Ahead (DA) charge types associated with the MISO
11 Day-Ahead market, the Financial Transmission Rights Charge types
12 associated with FTRs held in the Day-Ahead market, and the Real-Time
13 (RT) Charge types associated with the Real-Time energy market.

14

15 **Q. Can you explain Exhibit DE-16, Schedule F7-6?**

16 A. Exhibit DE-16, Schedule F7-6 includes certain items where we have
17 included the actual MISO billing data for the first twelve months (April 1,
18 2005 – March 31, 2006) of the MISO Energy Market. These items are
19 believed to be the more significant charge type items which have not been
20 accounted for elsewhere in other cost/credit estimates.

21

22 On Exhibit DE-16, Schedule F7-6 I am combining some of the related
23 charge types that I have discerned to be similar in nature from Exhibit DE-
24 16, Schedule F7-5 to develop some cost/credit projections for 2007. In
25 reviewing Exhibit DE-16, Schedule F7-6 it is important to understand the

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1 MISO sign convention for the charge types represented on a MISO
2 Settlement Statement. A positive value represents money that is owed to
3 MISO, and a negative value represents money owed to Detroit Edison.

4

5 **Q. What is the Net Revenue Sufficiency Guarantee and Make Whole**
6 **Payments item on Exhibit DE-16, Schedule F7-4, line 44?**

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

21

22 While much smaller in magnitude, there are Day Ahead counterparts to the
23 Real Time RSG charges and make whole payments. With the DA Revenue
24 Sufficiency Guarantee Distribution Amount and the DA Revenue Sufficiency
25 Guarantee Make Whole Payment Amount charge types, each generator that

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1 offers into the Day Ahead market is guaranteed full recovery of its startup,
2 no-load, and energy offer. Unlike the Real Time RSG Make Whole
3 Payment, the Day Ahead RSG Make Whole Payment is uplifted to all LSEs
4 that bid load into the Day Ahead Market.

5

6 The net cost of these four charge types for the first 12 months of the MISO
7 market is about \$19.0 million as shown on Exhibit DE-16, Schedule F7-6. In
8 my opinion MISO is aggressively taking steps to reduce RSG charges and
9 have already put in place certain changes to help achieve that objective.
10 For this reason, I have chosen to apply a 0.75 multiplier when making an
11 estimate for 2007. This will reduce this cost estimate to \$14.2 million for
12 2007, as shown in Exhibit DE-16, Schedule F7-6 and on line 44 of Exhibit
13 DE-16, Schedule F7-4.

14

15 **Q. How will Detroit Edison's customers be impacted by MISO congestion**
16 **costs?**

17 A It is unlikely that the Company can fully protect its customers against all the
18 congestion that will be experienced in the MISO Energy Market, even with
19 the purchase of additional FTRs. First of all, in previous attempts to obtain
20 FTRs during the MISO allocation process, Detroit Edison has not been
21 allocated all the FTRs that it requested due to certain identified transmission
22 constraints within MISO. MISO runs a simultaneous feasibility model to
23 determine the percentage of the FTRs requested by all parties that can
24 feasibly be awarded, and will only allocate the level of FTRs requested by
25 each party when the total allocation to all parties will pass the "simultaneous

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1 feasibility” test.

2

3 Second, the FTRs allocated by MISO will be in the form of FTR obligations.

4 This means that the Company is only protected by the FTR if the congestion

5 component of the LMP at the defined sink is higher than the congestion

6 LMP component value at the defined source, assuming some level of

7 congestion exists in the system. Each FTR is directional, typically defined

8 from a specific supply source to a load sink – Belle River Unit 1 to Detroit

9 Edison load is an example of an FTR that Detroit Edison will typically obtain

10 during the allocation process.

11

12 However, because each FTR is directional, should the opposite congestion

13 situation occur and the LMP value at the source is higher than the LMP

14 value at the sink due to congestion, even if only for a short period of time,

15 the FTR holder will have to pay the LMP congestion component between

16 the defined FTR sink and source. This “LMP reversal” situation could

17 occasionally occur in localized areas as a result of transmission and/or

18 generation outages, and also as a result of increased imports and/or exports

19 crossing through the ITC system. Until Detroit Edison gains more

20 experience that will come from having our load actually exposed to the LMP

21 market over a longer period of time, the Company’s total exposure to

22 congestion can only be generally estimated at this time. As discussed later

23 in my testimony, we are making an estimate of the value of the Company’s

24 FTRs to protect against congestion costs based on our experience to date

25 in the MISO Energy Market.

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1

2 **Q. How was the Net Congestion Cost value included on Exhibit DE-16,**
3 **Schedule F7-4, line 47 derived?**

4 A. As can be seen under the heading "Congestion Calculation" in Exhibit DE-
5 16, Schedule F7-6, the Company is using 12 months of historical MISO
6 Energy Market information to develop a projection for 2007. The first item
7 under this heading, "Congestion Amount between Generation and Load",
8 reflects the net differential congestion costs between Detroit Edison load
9 and generation. For example, in January 2006 the difference in the average
10 congestion cost component of the LMPs between the Monroe Unit 1
11 generation node and the Detroit Edison DECO.NEC average load node was
12 \$0.53/MWh (DECO.NEC is the name of the commercial price or "CP" node
13 representing the load weighted LMPs calculated for all the MISO defined
14 elemental pricing nodes in the ITC footprint). If the Monroe Unit 1
15 generated 500,000 megawatt hours during this month, then Detroit Edison
16 load would have paid \$265,000 more in congestion costs than would have
17 been received in the congestion component of LMP payments for the
18 Monroe Unit 1. In the final analysis, some of that congestion cost will be
19 offset by FTR credits, but I discuss that later.

20

21 To make an estimate of the 2007 congestion costs, we are taking the actual
22 average monthly congestion cost differences between each unit on the
23 Detroit Edison system and the Detroit Edison DECO.NEC load CP node,
24 such as the \$0.53/MWh value used in the above example for Monroe Unit 1
25 in January, 2006. Starting with the projected generation information for

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1 each unit as provided by Mr. Byron, we are multiplying the net MWhs
2 supplied by each unit for each month times the congestion cost differences
3 determined from historical information. That number is further adjusted to
4 account for the generation MWhs used to supply transmission losses, as will
5 be discussed later in more detail. The net cost determined in this manner is
6 our estimate for the “unadjusted” congestion costs associated with Detroit
7 Edison generation, which leads to the value of \$17.7 million shown on
8 Exhibit DE-16, Schedule F7-6.

9

10 Also shown on Exhibit DE-16, Schedule F7-6 is the actual congestion
11 costs/credits charge types associated with the historical purchases and
12 sales made in the first 12 months of the MISO Energy Market, shown as
13 Day-Ahead and Real-Time Financial Bilateral Transaction Congestion
14 Amounts, and the Day-Ahead and Real-Time rebates associated with our
15 Carve-out GFA (Ludington). Also shown is the net of the credits/charges
16 associated with holding FTRs during this period. The Company believes
17 that the net value of all these items, \$1.0 million, provides a reasonable
18 estimate of the congestion costs net of any FTR offset credits and net of the
19 real time congestion costs discussed below. This value is included as line
20 item 47 on Exhibit DE-16, Schedule F7-4 to reflect this cost estimate for
21 2007.

22

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

25 **A.** Yes. Because of a consistent shortfall in the collection of real-time

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1 congestion costs, in mid-Sept 2005 MISO decided to collect the shortfall
2 dollars through the use of the Revenue Inadequacy component of the Real
3 Time Revenue Neutrality charge type. With this change, we do not know
4 specifically the Detroit Edison costs related to these congestion costs.
5 However, for this proceeding we are capturing the effects of these costs by
6 including the RT Revenue Neutrality Uplift Amount as a separate item
7 included later in my testimony.

8

9 **Q. Can you explain Marginal Losses and how their use for dispatch**
10 **purposes could impact Detroit Edison's costs?**

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

18

19 Because the losses are charged based on a "marginal" cost versus an
20 "average" cost basis, it is inherent within the calculation methodology that
21 MISO will be over-collecting revenues associated with transmission losses.
22 MISO has developed a mechanism to return over-collected loss revenues to
23 each LSE on a load weighted basis.

24

25 To estimate the cost impacts of marginal losses, the Company used the

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1 same methodology it employed in determining congestion costs. A
2 reasonable estimate of the marginal losses costs can be determined by
3 looking at the difference in the average monthly LMP marginal losses paid
4 by the DECO.NEC load as compared to the average monthly marginal
5 losses component received by each generator in its LMP payments,
6 multiplied by the monthly Megawatt-hour output for the generator. In the
7 same manner as was done with the congestion calculation, we are also
8 reducing Megawatt-hour output for each generator to take out the
9 generation needed to cover transmission losses. By determining the
10 difference in these values from April 1, 2005 to March 31, 2006, and
11 multiplying that difference by the projected net generator Megawatt-hour
12 output for each month in 2007, the Company has estimated the total
13 marginal losses amount between the generators and the load to be \$91.8
14 million, as shown under the "Losses Calculation" heading in Exhibit DE-16,
15 Schedule F7-6. Also shown under this heading are the marginal loss costs
16 associated with purchases and or sales (DA and RT Financial Bilateral
17 Transaction Loss Amounts) and our Carve-Out GFA (DA and RT Loss
18 Rebate on Carve-out GFA). Next is the category "RT Distribution of Losses
19 Amount" which reflects the refunds made by MISO based on their estimate
20 of the over collection of the costs associated with losses due to the use of a
21 "marginal" loss calculation as part of the LMP calculation.

22

23 One other credit that is shown under the "Losses Calculation" in line 39 of
24 Exhibit DE-16, Schedule F7-6 is an estimate of the Revenue for
25 Transmission Losses. The Revenue for Transmission Losses item is

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1 intended provide a rough estimate of the credit due to Detroit Edison as a
2 result of generating to cover the transmission losses within the ITC zone.
3 Conceptually, if a system has 1% transmission losses, then 101 MW of
4 generation would be needed to supply 100 MW of load as measured at the
5 substation levels where the transmission system connects to the distribution
6 system. We are treating the extra 1 MW of generator revenues (when
7 multiplied times the generator LMPs) in this example as an additional credit
8 for customers that has not been captured elsewhere in our projections.

9

10 To approximate the Revenue for Transmission Losses, we start with the
11 assumption that 1.29% of the total output from Detroit Edison generation is
12 used to supply transmission losses, which was a value previously provided
13 by MISO to represent the average losses for the ITC system. This is only
14 an approximation, as in fact the actual losses vary each hour depending on
15 system load and what units are running for that hour. However, on an
16 average basis this is a reasonable value.

17

18 We have multiplied this generation output, calculated on a monthly basis,
19 times the monthly average LMP values for each generation unit. This
20 calculation led to a projected credit of \$32.7 million, as shown on line 39 of
21 Exhibit DE-16, Schedule F7-6.

22

23 The net cost for losses in 2007, as shown on Exhibit DE-16, Schedule F7-6
24 and as carried over to line 50 of Exhibit DE-16, Schedule F7-4 is \$46.6
25 million.

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1

2 **Q. Can you explain the Revenue Neutrality Uplift item on Exhibit DE-16,**
3 **Schedule F7-4, line 53?**

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

9 1) Uninstructed Deviation Charge Distribution Uplift

10 2) Revenue Inadequacy Uplift

11 3) Joint Operating Agreement (JOA) Uplift

12 4) Option B Grandfathered Agreement Financial Bilateral Transaction

13 Congestion Rebate Distribution Amount Uplift

14 5) Real-Time Revenue Sufficiency Guarantee Make Whole Payments

15 Second Pass Distribution Uplift

16 6) Carve-Out Grandfathered Agreement Congestion Rebate Distribution

17 Amount Uplift

18 As shown on Exhibit DE-16, Schedule F7-6, historically we experienced a
19 cost of about \$22.1 million for the first 12 months of the MISO Energy
20 Market. The Company is using that same value in projecting the cost for
21 2007, as shown in Exhibit DE-16, Schedule F7-4, line 53.

22

23 **Q. What is the Total Energy Market Costs shown on Exhibit DE-16,**
24 **Schedule F7-4, line 56?**

25 A. This is the sum of the costs associated with participating in the MISO

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1 Energy Market. During 2007 it is estimated to be approximately \$98.7
2 million. This is the price that Detroit Edison pays in order to be a participant
3 in the regional energy market and share in the economics and increased
4 reliability that such participation brings.

5

6 The total cost associated with procuring transmission services from
7 MISO/ITC and participating in the MISO Energy market is shown on line 59,
8 and is estimated to be approximately \$298.9 million for 2007.

9

10 **Q. Which of the other items on Exhibit DE-16, Schedule F7-5 have been**
11 **addressed elsewhere by other witnesses in this proceeding?**

12 A. The DA Asset Energy Amount and the RT Asset Energy Amount represent
13 the net of the generation revenues received by Detroit Edison generators
14 and the load payments made to serve Detroit Edison's load. These items
15 are included on the MISO statement, and are accounted for in Mr. Byron's
16 testimony and Exhibits.

17

18 **Q. Are there other charge type items on Exhibit DE-16, Schedule F7-5 that**
19 **have been addressed elsewhere in your testimony?**

20 A. Yes, I have previously provided an estimate of the 2006 costs for MISO
21 Schedules 16 and 17. The DA Market Administration Amount and the RT
22 Market Administration Amount have been discussed previously as the
23 charge types associated with MISO Schedule 17. Likewise, the FTR Market
24 Administration Amount is the charge type discussed for MISO Schedule 16.

25

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1 **Q. What are the charge types on Exhibit DE-16, Schedule F7-5, involving**
2 **Virtual Energy?**

3 A. The DA Virtual Energy Amount and the RT Virtual Energy Amount represent
4 the costs and credits associated with Ludington pumping. The MISO model
5 does not allow the Company to directly bid in the “load” associated with
6 Ludington pumping, therefore it is necessary to submit Virtual bids to
7 represent Ludington load in the MISO market. These two items can
8 essentially be netted to determine the “net” effect of the Virtual bids, which
9 is essentially the difference in the Day-Ahead and Real-Time LMPs at the
10 Ludington generator nodes. The Company’s experience with the MISO
11 market to date has been that there are times when the Day-Ahead hourly
12 LMPS are higher than those of the Real-Time LMPs, and other times when
13 the opposite is true. Given this variability, the Company has chosen not to
14 try to project a 2007 value for these charge types.

15

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

18 A. Yes. As discussed earlier, MISO is working to develop a market for
19 ancillary services. If this occurs, it is likely that MISO will file revised
20 schedules with FERC to recover the costs associated with administering the
21 ancillary services market in the same manner as was done for the FTR and
22 Energy Markets. If FERC accepts the schedules as part of the MISO
23 Transmission and Energy Market Tariff (TEMT) these expenses would be
24 imposed on Detroit Edison in the same manner as the other transmission
25 expenses.

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1

2 Currently there are still a number of changes being contemplated to MISO
3 Energy Market Rules, even after the market has been in operation for over
4 twelve months. The TEMT is still evolving and, as a result, there may be
5 additional cost impacts to Detroit Edison in 2007 and beyond that we are not
6 aware of at this time. It is difficult to estimate all the costs that the Company
7 will be facing until all the rules are finalized and participants gain more
8 experience with the MISO Energy Market.

9

10 When these additional MISO and/or ITC related charges do occur, they
11 should be approved for recovery in this case and future PSCR proceedings,
12 as they are largely beyond Detroit Edison's control and will continue to be
13 non-bypassable federally mandated charges required to participate in the
14 MISO wholesale energy market and to provide retail electric service to
15 Detroit Edison's customers.

16

17 **Q. Has the commencement of the MISO Energy Market changed any other**
18 **aspect of the Company's service?**

19 A. Yes. Prior to the start of the Energy Market, the Company provided an
20 optional retail access backup service to customers and marketers
21 participating in the Company's Electric Choice Program. The Company
22 provided customers and marketers a temporary alternative power source in
23 the event they experienced an outage for their generation source or in the
24 event that transmission capacity was constrained and their power could not
25 be delivered. Now that the MISO Energy Market is in place, MISO

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1 inherently provides this service to all market participants, including Electric
2 Choice participants. The EC-3 tariff has essentially become obsolete and
3 should be terminated.

4

5 **Q. Do you believe that the MISO and transmission expenses that you are**
6 **supporting are necessary, reasonable, and prudent?**

7 A. Yes, I do. All of the expense items listed on Exhibit DE-16, Schedule F7-4
8 are necessary and integral to Detroit Edison being able to provide retail
9 electric service to its customers. The rates upon which the expenses are
10 determined are subject to approval by FERC and comply with FERC's vision
11 for operation of the interconnected electric grid.

12

13 **SECTION 3 - PROPOSAL FOR MAKING MULTI-SUMMER CAPACITY**
14 **PURCHASES**

15

16 **Q. Can you explain the Company's proposal relative to "multi-summer"**
17 **capacity procurement?**

18 A. Yes. Currently Detroit Edison relies on short term (less than 6 months)
19 capacity contracts to cover its summer capacity shortfall. Furthermore, the
20 Company typically will only make purchases for the subsequent summer
21 period. For the summer of 2005 the Company entered into summer
22 capacity contracts for approximately 1700 MW of capacity and for the
23 summer of 2006 the Company has procured approximately 2200 MW of
24 capacity. As shown in Mr. Byron's testimony, the Company's need for
25 summer capacity is not forecast to diminish over the next several years.

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2

The Company is now proposing that it be allowed to enter into “multi-summer” contracts with suppliers for up to 5 summer periods. There will be a separate contract for each summer which will be less than 6 months in duration. However, the Company may enter into these “multi-summer” agreements for as long as 5 years to cover some portion of its summer capacity shortfall projection.

8

9

Q. Why is Detroit Edison proposing to contract for multiple summers?

10

A. Detroit Edison had been anticipating that at some point MISO would develop a capacity market similar to that currently used by PJM. However, MISO is currently taking the position that it will not implement a capacity market, but instead will promote the use of longer term bilateral contracts to ensure capacity adequacy and energy price stability in future years. MISO believes that the increasing volatility in MISO Energy Market prices will eventually drive Load Serving Entities (LSEs) toward the use of longer term contracts as a price hedge. Furthermore, PJM has recently filed a proposal with FERC to change its capacity market to make use of a “Reliability Pricing Model”, which in effect will also promote LSEs to enter into longer term bilateral agreements to cover future capacity needs.

21

22

With both MISO and PJM moving in this direction, and given the lack of any significant levels of new capacity coming in service over the next 3-5 years within the MISO region, the Company is concerned that it will be disadvantaged by contracting with suppliers for only one summer in

23

24

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1 advance, and may face a significant reliability concern should other entities
2 both within and outside of MISO lock up the capacity that is currently
3 available with longer term contracts to serve their own capacity needs.

4

5 **Q. What direction does the Company need from the Commission in order**
6 **to proceed to utilize a “multi-summer” capacity procurement process?**

7 A. The direction that the Company is requesting from the Commission is
8 clarification that entering into a series of separate summer contracts will not
9 invoke Section (13)(b) of Act 304 which requires the Commission to disallow
10 any capacity charges associated with power purchased for periods in
11 excess of 6 months unless the utility has obtained prior approval. It is
12 Detroit Edison’s view, for example, that entering into two separate four
13 month agreements to purchase capacity for the summers of 2006 and 2007
14 from a peaker owed by a third party does not constitute an eight month
15 contract but is instead two separate four month summer capacity contracts.

16

17 The Company is not asking for the preapproval of the expense associated
18 with the multi-summer agreements – each agreement can be evaluated
19 separately in the PSCR reconciliation proceeding for the applicable plan
20 year. However, the Company does need assurance that by entering into
21 the two separate four month agreements that this will not be viewed as a
22 violation of the six month rule, thus leading to a disallowance of the
23 Company’s capacity payments associated with those contracts.

24

25 While Detroit Edison does not expect advance approval of any costs

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1 associated with multi-summer contracts, it should be recognized that it is the
2 market price at the time a series of forward contracts are entered into that
3 must be recognized in evaluating whether the contract price for each year
4 was prudent. For example, in procuring a 5 year multi-summer contract it is
5 possible that the Company may pay a flat capacity rate for all 5 years, which
6 would likely imply that the cost for the first years would be higher than the
7 market price at the time, but the expectation would be that the price for the
8 later summers would be lower than the market price for those years.

9

10 In summary, Detroit Edison believes it to be both economically advisable
11 and prudent from a reliability perspective to lock up some level of its
12 projected capacity needs for multiple summers at today's market price, but
13 is unwilling to take the risk of disallowance if the multi summer procurement
14 strategy is viewed to invoke Section 6j(13)(b) of Act 304.

15

16 **Q. Does this complete your testimony?**

17 A. Yes, it does.