Indiana Michigan Power
P O Box 60
Fort Wayne, IN 46801
www.IndianaMichiganPower.com

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
P. O. Box 30221
Lansing, Michigan 48909

September 30, 2013

Dear Ms. Kunkle:

Re: Case No. U-17318

Attached for filing through the MPSC's Electronic Case Filings system is Indiana Michigan Power Company's (I&M) 2014 Power Supply Cost Recovery Plan Case, Case No. U-17318, along with a proposed Notice of Hearing.

Thank you for your attention to this matter. If you have any questions or comments, please contact me.

Sincerely,

Scott M. Krawec

Digitally signed by Scott M. Krawec
DN: cn=Scott M. Krawec, o=Indiana Michigan Power Company, ou=Director of Regulatory Services, email=smkrawec@aep.com, c=US
Date: 2013.09.30 12:43:06 -04'00'

Scott M. Krawec
Director of Regulatory Services

Attachment

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

NOTICE OF HEARING
FOR THE MICHIGAN ELECTRIC CUSTOMERS OF
INDIANA MICHIGAN POWER COMPANY
CASE NO. U-17318

- Indiana Michigan Power Company requests Michigan Public Service Commission approval to use a power supply cost recovery factor of 3.11 mills per kilowatt-hour (kWh) or $0.00311 per kWh to compute its Michigan electric customers' bills for the billing months of January 2014 through December 2014.

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

- You may call or write Indiana Michigan Power Company, 2425 Meadowbrook Road, Benton Harbor, Michigan 49023, (800) 311-6424, for a free copy of its application. Any person may review the application at the offices of Indiana Michigan Power Company.

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

DATE/TIME:	November 14, 2013, at 10:00 a.m. This hearing will be a prehearing conference to set future hearing dates and decide other procedural matters.
BEFORE:	Administrative Law Judge
LOCATION:	Constitution Hall 525 West Allegan 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 in advance to request mobility, visual, hearing or other assistance.

The Michigan Public Service Commission (Commission) will hold a hearing to consider Indiana Michigan Power Company's (I&M) September 30, 2013 application to use a power supply cost recovery (PSCR) factor of 3.11 mills per kWh for its Michigan electric customers' bills for the billing months of January 2014 through December 2014.

All documents filed in this case shall be submitted electronically through the Commission's E-Dockets website at: michigan.gov/mpscedockets. Requirements and instructions for filing can be found in the User Manual on the E-Dockets help page. Documents may also be submitted, in

Word or PDF format, as an attachment to an email sent to: mpscedockets@michigan.gov. If you require assistance prior to e-filing, contact Commission staff at (517) 241-6180 or by email at: mpscedockets@michigan.gov.

Any person wishing to intervene and become a party to the case shall electronically file a petition to intervene with this Commission by November 7, 2013. (Petitions to intervene may also be filed using the traditional paper format.) The proof of service shall indicate service upon I&M's attorney, Richard J. Aaron, Warner Norcross & Judd, LLP, One Michigan Avenue Building, 120 N. Washington Square, Suite 410, Lansing, Michigan 48933.

Any person wishing to appear at the hearing 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 or her wish to make a statement of position. All information submitted to the Commission in this matter becomes public information: available on the Michigan Public Service Commission's website, and subject to disclosure.

Requests for adjournment must be made pursuant to the Commission's Rules of Practice and Procedure R 460.17315 and R 460.17335. Requests for further information on adjournment should be directed to (517) 241-6060.

A copy of I&M's request may be reviewed on the Commission's website at: michigan.gov/mpscedockets, and at the office of Indiana Michigan Power Company, 2425 Meadowbrook Road, Benton Harbor, 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) 241-6180.

The Utility Consumer Representation Fund has been created for the purpose of aiding in the representation of residential utility customers in 1982 P.A. 304 proceedings. Contact the Chairperson, Utility Consumer Participation Board, Department of Licensing and Regulatory Affairs, P.O. Box 30004, Lansing, Michigan 48909, for more information.

Jurisdiction is pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1919 PA 419, as amended, MCL 460.54 et seq.; 1939 PA 3, as amended, MCL 460.1 et seq.; 1982 PA 304, as amended, MCL 460.6h 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.

INDIANA MICHIGAN POWER COMPANY

2014 POWER SUPPLY COST RECOVERY PLAN CASE

MPSC CASE NO. U-17318

FILED: SEPTEMBER 30, 2013

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of INDIANA MICHIGAN POWER COMPANY for approval of a Power Supply Cost Recovery Plan (2014)	)))))	Case No. U-17318

APPLICATION

Indiana Michigan Power Company (I&M), in accordance with 1982 PA 304 (Act 304), submits this Application requesting approval of its proposed 2014 Power Supply Cost Recovery (PSCR) Plan. In support of this Application, I&M respectfully represents to the Michigan Public Service Commission (MPSC or Commission) as follows:

1. I&M is a corporation organized and existing under the laws of the State of Indiana and is authorized to do business in the State of Michigan. I&M's principal offices and place of business are located in the City of Fort Wayne, Indiana. I&M has corporate power and authority, among other things, to engage in generating, transmitting, distributing, and selling electric energy within the State of Michigan and within the State of Indiana.

2. The electric system of I&M is a completely integrated and interconnected entity and is operated as a single utility. I&M's service area is located in southwestern Michigan and northern and eastern Indiana. I&M provides electric service to approximately 128,000 retail electric customers in the State of Michigan. I&M's service area in Michigan consists of customers in the counties of Allegan, Berrien, Cass, Kalamazoo, St. Joseph, and Van Buren.

3. I&M is a wholly-owned subsidiary of the American Electric Power Company,

Inc., and is an operating subsidiary in the American Electric Power System (AEP System) which is operated on an integrated, interconnected basis. The operating subsidiaries of the AEP System, including I&M, currently operate under arrangements which provide for the rendering of mutual assistance during emergencies, the effecting of maximum practical economy and dependability in day-to-day production of the electric power requirements of the AEP System and each of its operating subsidiaries, and the maximum utilization of opportunities for securing increased economies through coordination of planning, design, construction and maintenance of the AEP System and the system of each operating subsidiary, including I&M.

4. I&M's retail electric business in the State of Michigan is subject to the jurisdiction of the Commission pursuant to 1909 PA 106, as amended, MCL 460.551 et seq.; 1909 PA 300, as amended, MCL 462.2 et seq.; 1919 PA 419, as amended, MCL 460.51 et seq.; 1939 PA 3, as amended, including the amendments set forth in Act 304, MCL 460.1 et seq.

5. On September 27, 1983, the Commission approved I&M's requested PSCR Clause, with certain modifications, and rescinded I&M's previously approved fuel and purchased and interchanged power clauses. By its Order in Case No. U-9912, the Commission modified I&M's PSCR Clause to reflect separate PSCR factors for the St. Joseph and Three Rivers Rate Areas. By its Order in Case No. U-16180, the Commission modified I&M's PSCR Clause to reflect a single rate area with a unified PSCR Clause.

6. I&M's current PSCR Clause provides for the recovery through rates of the cost of power supply incurred to serve I&M's customers in the State of Michigan. I&M's approved PSCR Clause provides for 23.77 mills per kilowatt-hour (kWh), including

losses, of such costs to be recovered through base rates, with any increases or decreases from the base cost to be recovered through a PSCR factor.

7. To implement a PSCR Clause in its rates and rate schedules, I&M is required to file a PSCR Plan.

8. In addition to the requirements for the PSCR Plan in Paragraph 7 above, I&M is required to file a five-year forecast of the power supply requirements of its customers, its anticipated sources of supply, and projections of power supply costs.

9. I&M also requests continuation of the roll-in methodology approved in MPSC Case No. U-15004, I&M's 2007 PSCR Plan, which provides better rate stability, improves bill clarity, minimizes customer confusion and uncertainty, and is administratively more efficient and cost effective. I&M represents that in addition to I&M this similar methodology has been approved by the Commission in connection with other companies' PSCR and Gas Cost Recovery (GCR) clauses.

10. In accordance with the requirements of Act 304 and for the implementation of a PSCR Clause, I&M files this Application for approval of a PSCR Plan and for approval to apply PSCR factors to customers in the State of Michigan. As shown on Exhibit A, I&M requests authority to apply a PSCR factor of 2.55 mills per kWh to customers' bills for each of the billing months of January 2014 through December 2014. The proposed PSCR factor represents a decrease of 3.11 mills per kWh from the current PSCR factor.

11. I&M is filing with this Application its testimony and exhibits detailing its PSCR Plan as required by Act 304 and supporting its requested PSCR factor. The filed testimony and exhibits also contain I&M's five-year forecast of the power supply requirements of its customers, its anticipated sources of supply, and projections of

power supply costs in light of its existing sources of electrical generation and sources of electrical generation under construction.

WHEREFORE, I&M respectfully requests that the Commission:

1. Accept for filing this Application for approval of a PSCR Plan and PSCR factors.
2. Upon acceptance of the filing of this Application, fix a time and place for hearing and give notice thereof in accordance with the law and rules of practice established by this Commission.
3. Promptly make such investigation as it may deem necessary or advisable in the circumstances.
4. Authorize I&M to continue the roll-in methodology in connection with its PSCR clause.
5. Promptly enter its Order approving I&M's 2014 PSCR Plan and a PSCR factor of 2.55 mills per kWh for each of the billing months of January 2014 through December 2014
6. Grant I&M such other additional relief as it may deem appropriate.

Respectfully submitted,

INDIANA MICHIGAN POWER COMPANY

Scott M. Krawec

Digitally signed by Scott M. Krawec
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Date: 2013.09.30 12:44:11 -04'00'

By ______________________

Scott M. Krawec
Director of Regulatory Services

Richard J. Aaron (P35605)
Warner Norcross & Judd LLP
120 North Washington Square, Suite 410
Lansing, Michigan 48933
(517) 679-7400
raaron@wnj.com

Attorneys for Indiana Michigan Power Company

<u>VERIFICATION</u>

STATE OF INDIANA)
) SS
COUNTY OF ALLEN)

Scott M. Krawec being first duly sworn, deposes and says that he is Director of Regulatory Services of Indiana Michigan Power Company, an Indiana corporation; that he is duly authorized to and has executed the foregoing Application for and on behalf of Indiana Michigan Power Company; that he has read the same and knows the contents thereof, and that the same is true to the best of his knowledge, information, and belief.

Scott M. Krawec

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Scott M. Krawec

Subscribed and sworn to before me
this 30th day of September, 2013.

Regiana Sistevaris

Digitally signed by Regiana Sistevaris
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Regiana Maria Sistevaris
Notary Public, State of Indiana
County of Allen
My Commission Expires Mar 6, 2015

Exhibit A

Indiana Michigan Power Company
Determination of the Michigan Jurisdiction
Power Supply Cost Recovery Factor
January 2014 - December 2014

Line No.	Description	Twelve Month Totals	
1	Total Power Supply Costs (000's)	$454,231	
2	Net Energy Requirement (GWh)	24,154	
3	Line 1 / Line 2	18.80	Mills/kWh
4	Line 3 * 1.046	19.66	Mills/kWh
5	Plus: PSCR Transmission Factor (See Exhibit DLH-2)	7.30	Mills/kWh
6	Less Current Power Supply Cost Base	23.77	Mills/kWh
7	Subtotal - Line 4 plus Line 5 less Line 6	3.19	Mills/kWh
8	Estimated 2013 Over-recovery of $1,788,861 / 2,797,000,000 Est'd kWh 2014	(0.64)	Mills/kWh
9	PSCR Billing Factor for the Michigan Jurisdiction - Line 7 + Line 8	2.55	Mills/kWh

DIRECT TESTIMONY OF JON R. MACLEAN
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY
2014 PSCR PLAN CASE

A. Introduction

Q. Please state your name, business address, and present position.

A. My name is Jon R. MacLean. My business address is 1 Riverside Plaza, Columbus, Ohio, 43215. I am Manager - Resource Planning in the Resource Planning Section of the Corporate Planning & Budgeting Department of the American Electric Power Service Corporation, a wholly owned subsidiary of the American Electric Power Company, Inc. (AEP), the parent company of Indiana Michigan Power Company (I&M).

Q. Please briefly describe your educational and professional background.

A. I received a Bachelor of Science in Electrical Engineering degree from Ohio University in 1976. I was employed by Dayton Power and Light from 1976 through 1984 as an engineer in their Generation Planning Department. In 1984, I joined AEP as an Engineer in the Generation Performance Analysis Section (the predecessor to the current Resource Planning Section), was named to Senior Engineer in 1985, Principal Engineer in 2000, Manager – Production Resource Modeling in 2004 and my current position in 2011.

Q. Please briefly describe the responsibilities of the Resource Planning Section.

A. The Resource Planning Section is a part of the Corporate Planning and Budgeting Department, as is the Economic Forecasting Section, which carries out load forecasts for the System and its operating companies. The Resource Planning Section is responsible for analyses and evaluations of the AEP

System's load and capacity relationships, to determine the size, type, fuel, and timing of new supply-side resources (facilities or power purchases, or both), as well as for participation in evaluations regarding demand-side management (DSM) programs, as part of AEP's Integrated Resource Planning (IRP) process. It also develops generation and production cost forecasts for the AEP System for internal and external (regulatory) use, and carries out many other activities in areas related to resource planning.

Q. Please briefly outline your duties in the Resource Planning Section.

A. My responsibilities include supervising planning studies in the area of production costing for AEP's electric utility operating companies. These studies include fuel expense projections, marginal cost studies and other analyses that involve the use of electric energy costs. As manager, I have oversight responsibilities for a staff of engineers and analysts who carry out these and similar functions.

In performing my duties, I am familiar with the preparation and content of I&M's load forecast.

Q. Have you previously submitted testimony in any regulatory proceeding?

A. I have submitted testimony on behalf of I&M in its Power Supply Cost Recovery (PSCR) Plans for the plan years of 2007 through 2013. I have also submitted testimony on behalf of I&M before the Indiana Utility Regulatory Commission and on behalf of I&M affiliate Southwestern Electric Power Company before the Arkansas Public Service Commission and the Public

Utility Commission of Texas.

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

A. I will present testimony with regard to I&M's expected electric power demand and energy requirements and anticipated sources of power supply on a monthly basis for 2014 as well as on an annual basis for the five-year forecast period (2014-2018). I will describe the major contracts and power supply arrangements entered into by I&M for providing power supply. I will describe I&M's integrated resource planning process, and will also testify as to the reasonableness and prudence of I&M's decisions to provide power supply in the manner described. In addition, I will present testimony with respect to the reasonableness of I&M's reserve levels. It should be noted that members of the AEP East Pool Operating Committee agreed to terminate the pool Interconnection Agreement on December 17, 2010. In that regard, this forecast reflects the pool dissolved effective January 1, 2014 with I&M operating on a standalone basis for the years 2014 through 2018.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring exhibits IM-1 (JRM-1) through IM-9 (JRM-9).

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

A. Yes.

B. Load Forecast

Q. Has a forecast been made of the load requirements of I&M's customers?

A. Yes. Exhibit IM-1 (JRM-1) shows actual and forecast I&M seasonal peak internal demands, energy requirements and load factors for the years 2003 through 2018 along with annual and average rates of growth in demand and energy for the historical and forecast periods. Similarly, Exhibit IM-2 (JRM-2) presents the annual energy requirements for the residential, commercial and industrial sectors, other internal requirements, and the total internal energy requirements for I&M.

Q. What were the procedures used in making the I&M forecast?

A. Two distinct methods were used for forecasting energy. First, regression models with time series error terms were used to forecast energy sales up to 18 months ahead (short-term). These models use the most recent customer count, kWh sales data, weather data (in the form of degree days), and indicator (dummy) variables where needed.

The second method is the long-term process that starts with economic forecasts provided by Moody's Analytics for the United States as a whole, each state, and counties within each state. These include regional forecasts of such variables as employment, population, and income, as well as national forecasts of industrial production indices and producer and consumer price indices. The long-term energy forecast uses econometric models incorporating the economic forecast to produce a forecast of kWh sales. In the residential and commercial classes the models are end-use based econometric models, called Statistically Adjusted End-Use models, developed by Itron, Inc. Inputs such as regional and national economic and demographic conditions, energy prices, weather data, and customer-specific information are all utilized in producing the forecasts.

To forecast peak demand, MetrixLT a load representation model developed by Itron, Inc. was used. Model inputs include the blended short-term and long-term kWh sales forecast, weather data, load shapes, transmission and distribution losses, and calendar information.

Q. How is DSM included in the forecast?

A. The impacts of any long-standing existing DSM programs for each jurisdiction are embedded in the historical data that are supplied to the trend and econometric load-forecasting models. Thus, the models already account for these programs. Additionally, any new legislative or commission-approved DSM programs, such as the energy optimization programs specified in 2008 PA 295, are explicitly accounted for in the load forecast, as well as any additional proposed DSM programs. The aggregate DSM demand impacts for I&M are shown in Exhibit IM-7 (JRM-7).

C. Retail Competition

Q. Have you considered the impacts of Michigan electric industry restructuring and retail customer choice?

A. Yes, with regard to the impacts of Michigan electric industry restructuring and retail customer choice, i.e., Open Access Distribution (OAD), there are currently three alternative electric suppliers that have registered to compete for the Company's customers. Currently, participation in I&M's OAD is limited to

10 percent of I&M's 2011 weather-adjusted Michigan jurisdiction retail sales, or about 284 GWh. As of August 2013, I&M has no OAD customers. Accordingly, at this time, it is not appropriate to include any retail competition adjustments to the load forecast in this year's PSCR filing.

D. Other Load Commitments and System Sales

Q. In addition to the internal load of I&M, what other loads are part of this forecast?

A. The eastern zone of the AEP System is assumed to supply energy to the western zone of the System through May 2014, when the agreement for AEP East to AEP West capacity and energy transfers expires. In addition to that transaction, whenever I&M has energy available beyond what is needed to supply its internal load together with any contractual commitments to non-associated power systems, this energy is offered to the PJM market. Forecasted PJM market sales are based on an evaluation of the historical and anticipated amounts of energy available for such sales from I&M's own generation sources and a forecast of PJM market prices.

Q. Has a forecast been made of I&M's outside energy sales?

A. Yes. Exhibit IM-3 (JRM-3) includes a month-by-month projection for 2014 of I&M's energy sales for resale to non-associated systems. Similarly, Exhibit IM-4 (JRM-4) includes an annual projection of such sales for the five-year forecast period 2014-2018. In both exhibits, the other major components of I&M's load obligations are also included, to arrive at I&M's Total System Load.

E. Generating Capacity

Q. What generating capacity is currently available on the I&M system to supply the peak internal demands and energy requirements projected in Exhibits IM-1 (JRM-1) and IM-2 (JRM-2)?

A. Exhibit IM-5 (JRM-5) shows I&M's generating capacity in service. As can be seen from that exhibit, I&M's summer generating capacity in service aggregates to 5,494 MW.

Q. Does I&M have any capacity available under purchase agreements?

A. Exhibit IM-5 (JRM-5) shows the existing capacity available under purchase agreements on the I&M system. As can be seen from that exhibit, the capacity available under purchase agreements totals to 218 MW (summer rating).

Q. Please describe I&M's special power supply arrangements related to the Rockport Plant?

A. As illustrated in Exhibit IM-6 (JRM-6), the Rockport Plant consists of two 1,300-MW (nominal) generating units which are jointly owned or leased by I&M and AEP Generating Company (AEG), another AEP subsidiary. I&M's projected generating capacity resources reflect the following Rockport-related arrangements:

1. I&M's 50% ownership share of Rockport Unit 1 and I&M's 50% leased share of Rockport Unit 2 (i.e., 660 MW of Unit 1 and 650 MW of Unit 2).
2. AEG's 50% share of Rockport Unit 1 and AEG's 50% leased share of Rockport Unit 2 (i.e., 660 MW of Unit 1 and 650 MW

of Unit 2).

3. The Unit Power sale agreements among AEG, I&M, and Kentucky Power Company (KPCo), another AEP System operating company, under which I&M committed to purchase 70% of AEG's share of each Rockport unit, and KPCo committed to purchase 30% of AEG's share of each Rockport unit.

The agreements by which KPCo purchases shares of the Rockport units are through December 7, 2022. I&M's net capacity resources for 2014 thus include 1,122 MW of Rockport Unit 1 capacity (its own 660 MW share plus 462 MW purchased from AEG) and 1,105 MW of Rockport Unit 2 capacity (its own 650 MW share, plus 455 MW purchased from AEG).

Q. Please describe the general terms of I&M's purchase of Rockport Units 1 and 2 capacity from AEG.

A. Under the terms of the Unit Power Agreement between I&M and AEG (FERC Rate Schedule No. 1), dated March 31, 1982, as amended, AEG makes available to I&M up to 70% MW of the power and associated energy from its share of Rockport Units 1 and 2. I&M, in turn, pays to AEG amounts sufficient to cover, among other things, AEG's operating and other expenses related to the amount of power sold to I&M.

Q. Are any capacity additions projected for I&M?

A. Yes, at this time, the capacity plan for I&M includes the purchase of an additional 200 MW (nominal/nameplate rating) block of wind energy by 2015.

No new capacity additions are under construction, or have been approved for construction, for I&M.

Wind is generally considered an energy resource, not a capacity resource, due to the intermittent nature of wind. Nevertheless, wind resources receive an initial 13 percent capacity credit from PJM.

F. Environmental Issues

Q. Please discuss the relevant environmental regulations that affect I&M.

A. Compliance strategies to meet the requirements of the Clean Air Act (CAA) and its Amendments have been developed, as each rule became known.

On December 10, 2007, the U.S. District Court for the Southern District of Ohio entered a final settlement agreement among I&M and other AEP companies, the U.S. Environmental Protection Agency (EPA), eight states and 13 environmental organizations in connection with litigation regarding alleged violations of the New Source Review (NSR) provisions of the CAA. The NSR litigation settlement includes requirements to complete the installation of additional controls at specific units in the eastern zone of the AEP System and to achieve sufficient reductions to comply with annual emission caps for NO_X and SO_2 which decline to a steady-state level by 2019.

In February 2013, the parties to the NSR Consent Decree requested a federal court to approve a modification to that agreement. This modification includes lower system-wide SO_2 emission caps. Caps will take effect in 2016 and will become increasingly stringent until 2029. Under the new agreement, I&M will install lower-cost dry sorbent injection (DSI) technology for SO_2 emission reduction at both units of Rockport Plant and will make SO_2 emission reductions sooner than required under the consent decree and will also retire or refuel Tanners Creek Unit 4. As part of the agreement, I&M will install an additional 200 MW of wind energy.

The Clean Air Interstate Rule (CAIR) was finalized by EPA in 2005, and established a cap and trade program to reduce emissions of NO_x and SO_2 in covered states. Unrestricted interstate trading of allowances is allowed under CAIR. CAIR was appealed to the courts and remanded to EPA by the D. C. Circuit Court of Appeals in July 2008.

On August 21, 2012 the U.S. Court of Appeals for the District of Columbia Circuit vacated the Cross-State Air Pollution Rule. The Court remanded the rule back to the EPA. The CAIR will remain in effect for the present time.

The Mercury and Air Toxics Standards Rule (MATS) replaced the former Clean Air Mercury Rule that was vacated in 2008 by the D.C. Circuit Court of Appeals. The final MATS Rule became effective on April 16, 2012, with compliance required within three years of this date. This rule regulates emissions of hazardous air pollutants (HAPs) from coal and oil-fired electric generating units. HAPs regulated by this rule are: 1) mercury; 2) several non-mercury metals such as arsenic, lead, cadmium and selenium; 3) various acid gases including hydrochloric acid; and 4) many organic HAPs.

At this time, I&M's strategy for compliance with the aforementioned rules and agreements includes the installation of DSI technology, activated carbon injection and selective catalytic reduction at Rockport; Tanners Creek 1-3 will retire effective May 31, 2015; and Tanners Creek 4 will either be converted to burn natural gas or retired, also by May 31, 2015.

G. Reserve Margins

Q. What are I&M's projected reserve margins?

A. Assuming that I&M is viewed individually as part of a PJM planning perspective, Exhibit IM-7 (JRM-7) provides a projected PJM view of summer peak demands, capabilities, and margins for I&M for the 2014/15 PJM planning year through the 2018/19 planning year on an I&M "stand-alone" capacity position within PJM. This view is based on I&M continuing to participate, along with the other AEP East companies in the optional, FERC-authorized Fixed Resource Requirement (FRR) construct through at least the 2016/17 planning year. FRR requires AEP and I&M to set forth its future capacity resource profile and position under, essentially, a "self-planning" format that is predicated upon ensuring the stand-alone achievement of its future customer peak demand plus PJM Installed Reserve Margin (IRM) requirements. That projection assumes that the underlying minimum reserve margin criteria to be utilized in the determination of I&M capacity needs are the IRM levels shown in Column 20. With regard to projected margins, during the 2014 through 2018 period, reserve margins are adequate in that I&M's Net

Capacity Position (Column 19) is positive.

H. Integrated Resource Planning

Q. Please describe I&M's IRP process.

A. I&M's IRP process includes of the following steps:

1) Identify the current issues as they relate to resource planning, such as the environmental issues described in Section F;

2) Forecast demand and energy, as described in Section B;

3) Identify demand-side options, as described in Section B;

4) Identify current resources and projected changes to those resources, as depicted in Exhibit IM-7 (JRM-7);

5) Identify demand-side and supply-side resource options; and

6) Perform resource modeling, develop portfolios, and determine the ultimate plan.

I. Generation Forecast

Q. Have you developed a generation forecast for I&M to meet its customers' projected demands?

A. Yes. A forecast of generation (net energy output) from I&M's generating units and purchased power was developed for the five-year forecast period to meet I&M's Total System Load obligations shown in Exhibits IM-3 (JRM-3) and IM-4 (JRM-4) is presented by month in Exhibit IM-8 (JRM-8) for 2014, and annually in Exhibit IM-9 (JRM-9) for the years 2014 - 2018.

Q. Please explain how the generation forecast for I&M was developed.

A. I&M's energy sources for the forecast period include the Tanners Creek and Rockport (I&M's share) plants, the Cook Nuclear Plant, small hydroelectric plants located on the St. Joseph River in Michigan and Indiana, and purchases from the Ohio Valley Electric Corporation (OVEC) and wind energy purchases. The monthly and annual output of the hydroelectric plants was estimated, based on their historical average energy production. Nuclear energy production projections take into account maintenance and refueling requirements, and projected outage and other curtailment rates. Wind generation is estimated based on historical wind patterns.

I&M's generating units are operated along with the units of the other PJM members, to meet the total PJM load requirements on the most economical basis, based on price offers, subject to transmission limitations. Such operation was simulated in the development of the generation forecast by means of the *PLEXOS*® simulation model, a production-costing computer program developed by Energy Exemplar.

As noted in Section F. Environmental Issues, for purposes of this forecast, Tanners Creek 4 was assumed to be converted to natural gas, effective June 1, 2015. However, on September 17, 2013, shortly before the filing of this case, I&M announced that the decision was made that Tanners Creek 4 would be retired instead of refueled. Since the retirement of Tanners Creek 4 does not occur until mid-2015, I&M does not expect the retirement to impact the 2014 plan year projection in this filing. Given the timing of the decision and the filing deadline in this case, I&M was not able to model the impact of the retirement in its five year forecast. Nevertheless, I&M does not expect there to be a material difference if the retirement were reflected in its five year forecast.

Q. Please explain the Purchased Power projections in Exhibits IM-8 (JRM-8) and IM-9 (JRM-9).

A. I&M's Purchased Power for the forecast period consists of energy from: I&M's Unit Power purchase from AEG (from Rockport Units 1 and 2); I&M's share of OVEC; wind energy purchases and PJM market energy.

J. Conclusion

Q. In your opinion, with regard to the areas covered in your testimony, is the power supply cost recovery plan filed by I&M in this proceeding reasonable and prudent at this time?

A. Yes, I&M's power and energy requirements during the 12-month period covered by the plan (and during the five-year forecast period) will be supplied from its own generating units and its Unit Power purchase from AEG, together with other non-affiliated capacity and energy purchase commitments supplemented at any time when its resources are insufficient to meet its load by energy from the extensive PJM system.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Indiana Michigan Power Company(c)
Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor
2003-2018

	Winter Peak (a)			Summer Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	%Growth	GWh	%Growth	Load Factor %
Actual											
2003	01/07/03	3,683	---	08/21/03	4,223	---	4,223	---	22,864.7	---	61.8
2004	01/22/04	3,465	-5.9	07/22/04	4,016	-4.9	4,016	-4.9	22,938.9	0.3	65.0
2005	01/28/05	3,465	0.0	08/03/05	4,193	4.4	4,193	4.4	23,382.0	1.9	63.7
2006	12/08/05	3,537	2.1	07/31/06	4,650	10.9	4,650	10.9	24,371.0	4.2	59.8
2007	02/06/07	3,945	11.5	08/07/07	4,528	-2.6	4,528	-2.6	26,003.9	6.7	65.6
2008	01/25/08	3,875	-1.8	07/31/08	4,264	-5.8	4,264	-5.8	25,445.5	-2.1	67.9
2009	01/15/09	3,728	-3.8	06/25/09	4,262	0.0	4,262	0.0	24,297.0	-4.5	65.1
2010	12/10/09	3,858	3.5	07/23/10	4,474	5.0	4,474	5.0	25,829.2	6.3	65.9
2011	12/13/10	3,785	-1.9	07/21/11	4,837	8.1	4,837	8.1	25,928.6	0.4	61.2
2012	01/20/12	3,686	-2.6	07/06/12	4,726	-2.3	4,726	-2.3	25,731.0	-0.8	62.0
Forecast											
2013(b)		3,782	2.6		4,427	-6.3	4,451	-5.8	25,503.3	-0.9	65.4
2014		3,763	-0.5		4,393	-0.8	4,473	0.5	24,894.0	-2.4	63.5
2015		3,756	-0.2		4,372	-0.5	4,456	-0.4	24,804.7	-0.4	63.6
2016		3,717	-1.0		4,337	-0.8	4,419	-0.8	24,657.5	-0.6	63.5
2017		3,712	-0.1		4,328	-0.2	4,381	-0.9	24,550.1	-0.4	64.0
2018		3,692	-0.5		4,315	-0.3	4,366	-0.4	24,439.3	-0.5	63.9
Average Annual Growth Rates:											
2003-2012			0.0			1.3		1.3		1.3	
2013-2018			-0.5			-0.5		-0.4		-0.8	

Notes: (a) Actual winter peak for a year may occur in the 1st quarter of that year or in the 4th quarter of the preceding year.
(b) To date, actual winter 2012/13 peak is 3,782 MW, which occurred on 01/22/13, actual summer 2013 peak is 4,544 MW, which occurred on 09/10/13.
(c) Data reflect customers that receive generation, transmission and distribution services from I&M.

Indiana Michigan Power Company(b)
Annual Internal Energy Requirements
2003-2018

	Residential Sales		Commercial Sales		Industrial Sales		Other (a) Requirements		Total Internal Energy Requirements	
	GWh	%Growth	GWh	%Growth	GWh	%Growth	GWh	%Growth	GWh	%Growth
Actual										
2003	5,476.3	---	4,777.2	---	7,878.1	---	4,733.4	---	22,865.0	---
2004	5,524.1	0.9	4,893.8	2.4	8,109.4	2.9	4,411.8	-6.8	22,939.0	0.3
2005	5,985.6	8.4	5,089.6	4.0	8,089.7	-0.2	4,217.1	-4.4	23,382.0	1.9
2006	5,783.9	-3.4	5,067.7	-0.4	8,049.2	-0.5	5,470.2	29.7	24,371.0	4.2
2007	6,131.7	6.0	5,373.3	6.0	7,967.1	-1.0	6,531.9	19.4	26,004.0	6.7
2008	6,058.6	-1.2	5,272.0	-1.9	7,535.7	-5.4	6,579.6	0.7	25,446.0	-2.1
2009	5,766.8	-4.8	5,038.4	-4.4	6,761.9	-10.3	6,729.9	2.3	24,297.0	-4.5
2010	6,083.1	5.5	5,121.0	1.6	7,444.9	10.1	7,180.2	6.7	25,829.2	6.3
2011	5,997.3	-1.4	5,044.9	-1.5	7,522.9	1.0	7,363.4	2.6	25,928.6	0.4
2012	5,770.9	-3.8	5,022.7	-0.4	7,578.6	0.7	7,358.7	-0.1	25,731.0	-0.8
Forecast										
2013	5,775.5	0.1	4,915.4	-2.1	7,382.8	-2.6	7,429.6	1.0	25,503.3	-0.9
2014	5,625.6	-2.6	4,858.7	-1.2	7,165.9	-2.9	7,243.9	-2.5	24,894.0	-2.4
2015	5,574.3	-0.9	4,842.4	-0.3	7,115.5	-0.7	7,272.5	0.4	24,804.7	-0.4
2016	5,535.5	-0.7	4,841.1	0.0	6,999.9	-1.6	7,280.9	0.1	24,657.5	-0.6
2017	5,502.7	-0.6	4,837.2	-0.1	6,882.5	-1.7	7,327.8	0.6	24,550.1	-0.4
2018	5,469.6	-0.6	4,831.3	-0.1	6,774.3	-1.6	7,364.1	0.5	24,439.3	-0.5
Average Annual Growth Rates										
2003-2012		0.6		0.6		-0.4		5.0		1.3
2013-2018		-1.1		-0.3		-1.7		-0.2		-0.8

Notes: (a) Other requirements includes other internal sales, and losses and energy unaccounted for.
(b) Data reflect customers that receive generation, transmission and distribution services from I&M.

Indiana Michigan Power Company
Monthly and Annual Energy Sales, Internal and System Loads
2014
(Thousands of Megawatthours)

Line No.	Energy Sales to Ultimate Customers	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
1.	Residential	657.9	510.1	470.9	339.2	346.3	439.1	608.2	529.5	407.4	338.2	406.0	572.9	5,625.6
2.	Commercial	398.3	353.3	394.4	355.5	405.9	447.7	482.9	423.2	411.0	419.1	370.9	396.6	4,858.7
3.	Industrial	549.6	575.1	608.8	592.0	627.8	618.7	605.4	590.3	578.6	633.6	611.9	574.1	7,165.9
4.	Other Ultimate	8.0	5.5	7.3	4.5	5.3	6.2	4.5	6.0	5.0	7.7	6.7	4.5	71.2
5.	Total Ultimate Sales	1,613.8	1,444.0	1,481.3	1,291.1	1,385.3	1,511.7	1,701.0	1,549.0	1,402.1	1,398.6	1,395.5	1,548.1	17,721.4
	Energy Sales for Resale to Internal Customers													
6.	Municipals and Cooperatives	438.4	402.3	409.3	389.0	405.6	424.7	463.3	462.4	409.7	406.8	404.2	439.8	5,055.3
7.	Total Internal Sales for Resale	438.4	402.3	409.3	389.0	405.6	424.7	463.3	462.4	409.7	406.8	404.2	439.8	5,055.3
	Internal Load													
8.	Total Internal Sales (Sum 5 and 7)	2,052.2	1,846.2	1,890.6	1,680.1	1,790.8	1,936.4	2,164.3	2,011.4	1,811.8	1,805.4	1,799.7	1,987.9	22,776.7
9.	Total Losses	197.9	176.0	145.3	207.5	136.7	148.4	166.5	270.0	174.9	137.9	137.5	218.7	2,117.3
10.	Total Unadjusted Internal Load	2,250.1	2,022.2	2,035.9	1,887.6	1,927.5	2,084.8	2,330.8	2,281.4	1,986.7	1,943.3	1,937.2	2,206.5	24,894.0
11.	PJM Marginal Losses	(66.1)	(60.2)	(60.6)	(56.3)	(57.4)	(62.0)	(69.5)	(67.9)	(59.2)	(57.9)	(57.7)	(65.8)	(740.7)
12.	Total Internal Load	2,184.0	1,962.0	1,975.3	1,831.3	1,870.1	2,022.8	2,261.3	2,213.6	1,927.5	1,885.4	1,879.5	2,140.8	24,153.4
	Energy Sales for Resale													
13.	I&M System Sales to West	29.3	64.0	13.6	11.8	22.2	-	-	-	-	-	-	-	140.9
14.	I&M System Sales	1,192.9	1,168.8	1,175.3	889.3	494.3	871.5	810.1	772.8	855.6	569.2	317.9	771.5	9,889.2
15.	Total Sales for Resale to Non-Associated Systems	1,222.2	1,232.8	1,188.8	901.1	516.6	871.5	810.1	772.8	855.6	569.2	317.9	771.5	10,030.1
16.	Total System Load (Sum of 12 and 15)	3,406.2	3,194.7	3,164.1	2,732.4	2,386.6	2,894.3	3,071.4	2,986.3	2,783.1	2,454.6	2,197.5	2,912.2	34,183.4

Indiana Michigan Power Company
Annual Energy Sales, Internal and System Loads
2014-2018
(Thousands of Megawatthours)

Line No.	Energy Sales to Ultimate Customers	2014	2015	2016	2017	2018
1.	Residential	5,625.6	5,574.3	5,535.5	5,502.7	5,469.6
2.	Commercial	4,858.7	4,842.4	4,841.1	4,837.2	4,831.3
3.	Industrial	7,165.9	7,115.5	6,999.9	6,882.5	6,774.3
4.	Other Ultimate	71.2	70.7	70.2	69.7	69.2
5.	Total Ultimate Sales	17,721.4	17,602.8	17,446.8	17,292.0	17,144.4
	Energy Sales for Resale to Internal Customers					
6.	Municipals and Cooperatives	5,055.3	5,092.8	5,112.2	5,174.6	5,221.3
7.	Total Internal Sales for Resale	5,055.3	5,092.8	5,112.2	5,174.6	5,221.3
	Internal Load					
8.	Total Internal Sales (Sum 5 and 7)	22,776.7	22,695.7	22,559.0	22,466.7	22,365.8
9.	Total Losses	2,117.3	2,109.0	2,098.5	2,083.4	2,073.5
10.	Total Unadjusted Internal Load	24,894.0	24,804.7	24,657.5	24,550.1	24,439.3
11.	PJM Marginal Losses	(740.7)	(738.0)	(733.6)	(730.4)	(727.1)
12.	Total Internal Load	24,153.4	24,066.6	23,923.9	23,819.7	23,712.2
	Energy Sales for Resale					
13.	I&M System Sales to West	140.9	-	-	-	-
14.	I&M System Sales	9,889.2	8,530.7	9,708.8	11,064.8	10,901.0
15.	Total Sales for Resale to Non-Associated Systems	10,030.1	8,530.7	9,708.8	11,064.8	10,901.0
16.	Total System Load (Sum of 12 and 15)	34,183.4	32,597.3	33,632.7	34,884.5	34,613.2

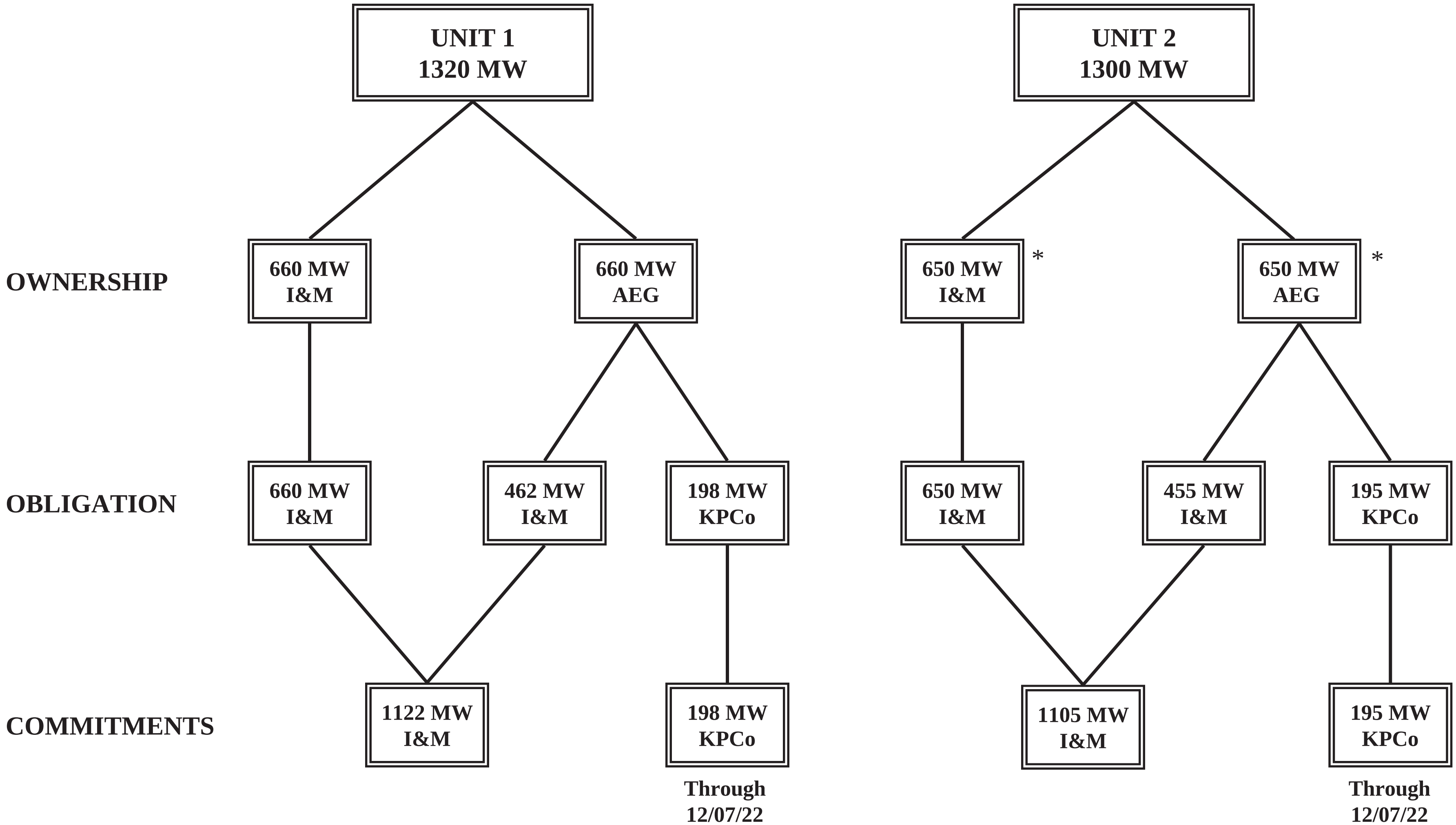
INDIANA MICHIGAN POWER COMPANY
GENERATING CAPACITY IN SERVICE

			CAPABILITY - MW	
			I&M	
Plant	**Unit**	**Notes**	**Winter(a)**	**Summer(b)**
Cook (Nuclear)	1-2		2,191	2,059
Rockport (Coal)	1-2		2,227	2,223
Tanners Creek (Coal)	1-4		995	982
Conventional Hydro			15	12
	Total		5,428	5,276
Purchases				
OVEC (Coal)	1-6	(c)	169	168
Fowler Ridge Phase 1 & 3 (Wind)		(d)	20	19
Fowler Ridge Phase 2 (Wind)		(d)	10	9
Wildcat (Wind)		(d)	13	13
Robert Mone (Gas)	1-3	(e)	29	8
SEPA (Hydro)		(f)	1	1
Total Purchases			242	218
Total Incl. Purchases			5,670	5,494

Notes:

a. Expected capacity at time of I&M (January) Winter 2012/13 peaks.
b. Expected capacity at time of I&M (July) Summer 2013 peaks.
c. I&M's PPR share of OVEC purchase.
d. Wind capacity values are 13% of nameplate or based on historical performance
e. I&M's MLR share of the Mone purchase.
f. I&M's MLR share of the SEPA purchase.

ROCKPORT PLANT
OWNERSHIP, OBLIGATION AND COMMITMENTS



* Both I&M and AEG sell and leaseback their respective shares of Rockport Unit 2. The lessors are non-affiliated, non-utility institutions. During the term of the lease, I&M and AEG each has full entitlement to 50% of the power and energy from Rockport Unit 2.

INDIANA MICHIGAN POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
(2014/2015 - 2018/2019)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)
					=(1)+(3)				=((4)-((5)*(6)))*(7)		=(8)+(9)						=(11)-(12)+Sum(14)+(15)		=(16)*(1-(17))	=(18)-(10)		=((10)+((5)*(6)*(7))/(1+(20)))	=(19)/(21)	=(20)+(22)
		Obligation to PJM										Resources								PJM Reserve Margin Position				
														Planned Capacity Additions										
Planning Year		Internal Demand(a)	DSM(b)	Projected DSM Impact(c)	Net Internal Demand	Interruptible Demand Response(d)	Demand Response Factor	Forecast Pool Req't(e)	UCAP Obligation	Net UCAP Market Obligation(f)	Total UCAP Obligation	Existing Capacity & Planned Changes(g)	Net Capacity Sales	Units	MW(h)	Annual Purchases	Net ICAP	AEP EFORd(i)	Available UCAP	I&M Net Capacity Position	Installed Reserve Margin	Total UCAP Obligation Less IDR and IRM	I&M Reserve Margin Above PJM IRM	Total I&M Reserve Margin
2014/15	(j)	4,348	(59)	0	4,348	305	0.956	1.089	4,417	0	4,417	5,494	0	0	0	0	5,494	7.46%	5,084	667	15.90%	4,085	16.33%	32.23%
2015/16	(j)	4,530	(92)	(8)	4,522	327	0.958	1.085	4,566	0	4,566	4,994	0	200 MW Wind	26	0	5,020	7.58%	4,639	73	15.30%	4,255	1.72%	17.02%
2016/17	(j)	4,453	(121)	(20)	4,433	355	0.955	1.090	4,464	0	4,464	4,994	0	0	0	0	5,020	5.54%	4,742	278	15.60%	4,181	6.65%	22.25%
2017/18		4,237	(143)	(31)	4,206	310	0.955	1.090	4,262	0	4,262	5,037	(56)	0	0	0	5,119	5.47%	4,839	577	15.60%	3,966	14.55%	30.15%
2018/19		4,243	(163)	(59)	4,183	312	0.955	1.090	4,236	0	4,236	5,067	(55)	0	0	0	5,148	5.48%	4,866	630	15.60%	3,946	15.97%	31.57%

Notes: (a) Based on (January 2013) Load Forecast (with implied PJM diversity factor)
(b) Existing plus approved and projected "Passive" EE, and IVV
(note: these values & timing are for reference only and are not reflected in position determination)
(c) For PJM planning purposes, the ultimate impact of new DSM is 'delayed' ~4 years to represent the ultimate recognition of these amounts through the PJM-originated load forecast process
(d) Interruptible Demand Response (IDR) approved by PJM in the prior planning year plus forecasted "Active" DR
(e) Installed Reserve Margin (IRM) = 15.9%(2013-2014), 15.3%(2015), 15.6%(2016-2030)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)
(f) Includes company MLR share of: FRR view of obligations only
(g) Reflects the members ownership ratio of following summer capability assumptions:
AEP share of OVEC capacity (43.47% PPR-share of full ~2,180 total capacity)
Assumes hydro units are derated to August average output in 2017/18
Wind Farm PPAs
EFFICIENCY IMPROVEMENTS:
2018/19: Rockport 1: 36 MW (turbine)
2017/18: Cook 2: 50 MW (turbine)
GAS CONVERSION RERATES:
2015/16: Tanners Ck. 4: 482 MW
RETIREMENTS:
2015/16: Tanners Ck. 1-3; Tanners Ck. 4 (Coal)
(h) New wind capacity value is assumed to be 13% of nameplate
(i) Based on 12-month avg. AEP EFORd in eCapacity as of twelve months ended 9/30 of the previous year
(j) PJM forecast

INDIANA MICHIGAN POWER COMPANY
Sources of Energy
2014
(Thousands of Megawatthours)

Line No.		Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Total
1	GENERATION													
2	Fossil	1,089.6	1,068.7	885.3	640.6	461.4	859.1	966.8	904.8	878.4	825.1	343.0	715.7	9,638.5
3	Nuclear	1,548.6	1,398.7	1,548.6	1,498.7	1,517.5	1,446.6	1,455.3	1,462.4	1,276.0	968.3	1,498.7	1,548.6	17,168.0
4	Hydro	10.3	9.6	11.7	12.2	10.6	8.5	7.7	6.9	5.1	7.3	8.6	10.6	109.1
5	Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	Total Generation	2,648.5	2,477.0	2,445.6	2,151.5	1,989.5	2,314.2	2,429.8	2,374.1	2,159.5	1,800.7	1,850.3	2,274.9	26,915.6
7	PURCHASED POWER													
8	AEG	594.0	577.3	572.8	408.2	255.4	468.7	522.6	484.8	497.7	489.6	182.6	414.3	5,468.1
9	OVEC	91.0	69.2	71.6	73.4	70.1	62.9	73.0	70.1	59.9	71.3	58.6	64.2	835.4
10	Wind	72.6	71.0	73.7	86.1	56.0	43.0	31.5	30.2	47.4	70.7	77.7	74.0	733.9
11	Other Purchase	0.0	0.3	0.4	13.1	15.5	5.5	14.5	27.1	18.7	22.3	28.2	84.9	230.4
12	Total Purchased Power	757.7	717.8	718.5	580.8	397.1	580.1	641.5	612.2	623.6	653.8	347.2	637.3	7,267.8
13	TOTAL SOURCES OF ENERGY	3,406.2	3,194.7	3,164.1	2,732.4	2,386.6	2,894.3	3,071.4	2,986.3	2,783.1	2,454.6	2,197.5	2,912.2	34,183.4

INDIANA MICHIGAN POWER COMPANY
Sources of Energy
2014-2018
(Thousands of Megawatthours)

Line No.		2014	2015	2016	2017	2018
1	GENERATION					
2	Fossil	9,638.5	7,765.6	8,584.2	8,687.1	8,527.7
3	Nuclear	17,168.0	17,123.9	16,136.6	17,585.5	17,505.7
4	Hydro	109.1	111.7	110.6	110.5	110.5
5	Wind	0.0	0.0	0.0	0.0	0.0
6	Total Generation	26,915.6	25,001.2	24,831.4	26,383.1	26,143.9
7	PURCHASED POWER					
8	AEG	5,468.1	4,903.8	5,862.8	5,788.5	5,701.5
9	OVEC	835.4	1,001.6	1,190.4	1,267.4	1,280.3
10	Wind	733.9	1,385.2	1,390.7	1,385.2	1,385.2
11	Other Purchase	230.4	305.6	357.5	60.4	102.3
12	Total Purchased Power	7,267.8	7,596.1	8,801.3	8,501.5	8,469.3
13	TOTAL SOURCES OF ENERGY	34,183.4	32,597.3	33,632.7	34,884.5	34,613.2

DIRECT TESTIMONY OF MICKEY L. BELLVILLE
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY
2014 PSCR PLAN CASE

Q. Please state your name and business address.

A. My name is Mickey L. Bellville and my business address is 500 Circle Drive, Buchanan, Michigan 49107.

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

A. I am employed by Indiana Michigan Power Company (I&M or Company) as the Manager of Nuclear Engineering, which coordinates the supply and management of nuclear fuel and related services for the Donald C. Cook Nuclear Plant (Cook Nuclear Plant). My responsibilities include supervising activities related to the supply of nuclear fuel, including its procurement, performance, disposal, reload licensing, reactor engineering, and plant support.

Q. Please briefly describe your educational background.

A. In 1982, I graduated from the University of Michigan with a Bachelor of Science degree in Engineering. In 1999, I received a Master of Business Administration degree from Bethel College.

Q. Please briefly describe your professional background.

A. From May 1982 to March 1995, as an Engineer with Duke Power Company, I was involved with commercial nuclear fuel contract development, contract language interpretation, and contract negotiations. I was responsible for developing procurement strategy, economic analysis, budget preparation, and negotiation strategy and techniques.

From March 1995 to July 1996, I was employed as an Engineer at Consumers Power Company and was responsible for front end fuel cycle coordination, technical reload interface, economic analysis coordination, vendor interface for fuel management activities, budgetary control, cost/risk analysis, and fuel planning and scheduling.

From July 1996 to February 2004, while being employed by my current employer I&M, I held responsibilities for developing a strategic partnership contract with Framatome, Inc. that included services for engineering, projects, and outage services at cost, including, profit/incentives based on performance metrics. In addition, I evaluated projects through financial analysis and capital project planning and budgeting.

From February 2004 to May 2004, I held Project Manager responsibilities that included project management for the Fuel Transition Project (FTP). Areas of management for the FTP included safety analysis, licensing, neutronics, Framatome interface, and budgetary controls.

From May 2004 to February 2007, I was the Nuclear Fuel Supervisor and my responsibilities included core reload activities, fuel procurement, cost recovery filings, vendor manufacturing oversight, regulatory administration, fuel integrity monitoring, fuel inspection coordination, and Updated Final Safety Analysis Report updates.

Beginning in February 2007, I became the Manager of Nuclear Engineering and my responsibilities include oversight of all nuclear fuel, nuclear safety analysis, and reactor engineering activities in support of Cook Nuclear Plant.

Q. Have you previously testified or submitted testimony in any regulatory proceedings?

A. Yes. I have submitted testimony to the Michigan Public Service Commission in I&M's 2006 through 2012 Power Supply Cost Recovery (PSCR) Reconciliation Cases and I&M's 2008 through 2013 PSCR Plan Cases. In addition, I have submitted testimony before the Indiana Utility Regulatory Commission in I&M fuel cost proceedings.

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

A. The purpose of my testimony in this case is to: (1) describe the relevant responsibilities of the Nuclear Engineering Department as they pertain to the 2014 nuclear fuel costs, (2) support projected nuclear fuel costs used by Witness Riley, (3) describe major nuclear fuel contracts that affect I&M's 2014 nuclear fuel costs, and (4) discuss the reasonableness and prudence of the actions taken to minimize I&M's actual nuclear fuel costs.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring Exhibits IM-10 (MLB-1) and IM-11 (MLB-2) that provide the monthly expensing of nuclear fuel costs.

Q. Do you adopt these exhibits in support of the PSCR Plan Case?

A. Yes.

Q. What are the responsibilities of the Nuclear Engineering Department as it relates to nuclear fuel requirements and nuclear fuel related activities?

A. The responsibilities of the Nuclear Engineering Department as it relates to nuclear fuel requirements and related activities are:

- To constantly monitor and evaluate market, political, regulatory, and technical conditions that may affect the secure supply of economical and licensable nuclear fuel.
- To prepare bid specifications and evaluate bid proposals for the purchase of nuclear fuel and nuclear fuel related services, as well as the storage, shipping, and disposal of spent nuclear fuel.
- To negotiate contracts with suppliers of nuclear fuel and nuclear fuel related services.
- To establish the most economic operating parameters of each cycle with consideration of the operating requirements of the American Electric Power (AEP) System.
- To evaluate and select economic core loading plans and to administer the purchase schedule and contracts necessary to implement these plans.
- To provide support to a nuclear fuel quality assurance program for the purpose of assuring that the nuclear fuel is built according to its design criteria and specifications.
- To perform nuclear fuel economic analyses and provide

current data and projections of future expenditures to other departments within AEP and I&M.

- To have core physics parameters verified to insure that the operation and performance of the nuclear fuel is within safety limits and agree with predictions.
- To ensure that the required logistics of the nuclear fuel cycle takes place for each reload batch, consisting of new nuclear fuel assemblies placed in the reactor core during a refueling outage. This may include uranium mining and milling, conversion to uranium hexafluoride, enrichment, fuel fabrication, fuel assembly shipment, and reactor refueling operations.

Q. Please describe the major contracts entered into by I&M for supplying nuclear fuel to the Cook Nuclear Plant that affect the expected 2014 nuclear fuel costs.

A. A summary of the major contracts I&M entered into for the supply and disposal of nuclear fuel for Cook Nuclear Plant that will affect the 2014 costs follows:

1. <u>Long-Term Contracts</u>

a. Westinghouse Electric Company

Contract dated March 15, 1991

Nuclear Fuel Fabrication

This contract calls for the design and fabrication of multiple reload batches of nuclear fuel for Units 1 and 2 of the Cook Nuclear Plant. The first reload batch under this contract was delivered in 1993. The contract includes fabrication of the fuel assemblies and all transportation of special nuclear material, fuel assemblies, and components incident to the fabrication process.

b. Westinghouse Electric Company
Contract dated June 1, 2012
Nuclear Fuel Fabrication

This contract calls for the design and fabrication of multiple reload batches of nuclear fuel for Units 1 and 2 of the Cook Nuclear Plant. The first reload batch under this contract was delivered in 2013. The contract includes fabrication of the fuel assemblies and all transportation of special nuclear material, fuel assemblies, and components incident to the fabrication process.

c. United States of America (Department of Energy [DOE] as representative)
Contract dated June 13, 1983
Nuclear Waste Disposal

I&M has contracted with the DOE to take title to and dispose of the spent nuclear fuel or high-level waste.

I&M's PSCR Plan Case includes post-April 6, 1983, spent nuclear fuel fees.

2. Mid-Term Contracts

a. Cameco (uranium hexafluoride)

b. United States Enrichment Corporation (uranium hexafluoride and enriched uranium)

c. Urenco (uranium hexafluoride and enriched uranium)

d. Areva (enriched uranium)

These contracts are for the procurement of materials and services on a two- to five-batch basis.

3. Spot Procurement Agreements and Short-Term Contracts

a. Global Nuclear Services and Supply/MTM Trading LLC (uranium hexafluoride)

b. Nufcor International Limited (uranium hexafluoride)

c. Traxys North America (uranium hexafluoride)

These agreements and contracts are for the procurement of materials and services for the fuel cycle on a one-time spot procurement or short-term basis.

Q. Can you briefly describe the long-term contract associated with nuclear waste disposal?

A. Yes. The Nuclear Waste Policy Act (NWPA) of 1982 established that the Federal government had responsibility to provide for the permanent disposal of spent nuclear fuel (SNF). Thereafter, the DOE entered into standard contracts for the disposal of SNF and the standard contracts provided for a fee to be paid by generators and owners of the SNF. Nuclear utilities, including I&M, had no practical alternatives other than to sign standard contracts with the DOE in order to obtain and maintain operating licenses. I&M's contract with the DOE and the DOE's obligation under the contract remain in effect.

Q. How were I&M's projected post-April 6, 1983, SNF costs determined?

A. Projected post-April 6, 1983, SNF costs were calculated based on the rate of one mill per kilowatt-hour (kWh) of electricity generated and sold in accordance with the NWPA of 1982.

Q. Will I&M have any intermediate actions for managing SNF, prior to permanent disposal as established in the NWPA of 1982?

A. Yes. The Federal government currently does not have a permanent disposal facility in operation. As such, I&M will be required to store SNF at Cook Nuclear Plant’s site in canisters that will then be loaded into Dry Storage Casks until permanent disposal becomes available.

Q. Will this canister storage of SNF affect the expected 2014 nuclear fuel costs?

A. No.

Q. Please describe any additional obligations entered into by I&M that do affect the expected 2014 nuclear fuel costs.

A. Cook Nuclear Plant has entered into Nuclear Fuel Leases for reload batches since a Nuclear Fuel Lease was signed between I&M and Citicorp Leasing, Inc., with an effective date of December 14, 2007 for Batch 19 in Unit 2. Costs associated with this lease include the monthly rent component, finance charges, and administration fees. The monthly rent component for the nuclear fuel is determined by multiplying the number of British Thermal Units (BTUs) consumed by the nuclear fuel during such month and the dollar amount per BTU (BTU charge) as established in an Individual Leasing Record. During months for which no BTUs are consumed, the only expenses incurred include the finance charges and administration fees. The lease term for the nuclear fuel leased is for a period not to exceed sixty (60) months.

Q. Why did I&M enter into this obligation?

A. Nuclear Fuel Leases provide a lower cost financing option versus using internal capital funds to purchase the fuel.

Q. Does I&M lease nuclear fuel from any other financial institutions?

A. Yes. I&M also successfully pursued the following fuel lease agreements:

Unit	Batch	Provider	Effective Date
2	20	Metropolitan Life Insurance Company / DCC Fuel, LLC	09/24/2009
1	25	Metropolitan Life Insurance Company / DCC Fuel II, LLC	04/13/2010
2	21	Wells Fargo Delaware Trust Company / DCC Fuel III, LLC	12/07/2010
1	26	Metropolitan Life Insurance Company / DCC Fuel IV, LLC	11/01/2011
2	22	Metropolitan Life Insurance Company / DCC Fuel V, LLC	4/27/2012
1	27	Mizuho Corporate Bank / DCC Fuel VI, LLC	5/16/2013

Q. Will these fuel leases affect the projected 2014 nuclear fuel costs?

A. Yes, as shown in Exhibits IM-10 (MLB-1) and IM-11 (MLB-2), the projected 2014 nuclear fuel costs will be impacted. In particular, basic rent, financing charges and other administrative fees will be applied. This is the result of the continued service in 2014 of Unit 1 Batch 25, 26 and 27 as well as Unit 2 Batches 21 and 22.

Q. Will these fuel leases also affect the projected nuclear fuel costs beyond 2014?

A. Yes, the impact of these leases on projected nuclear fuel costs for 2014-2018 are also shown on the exhibits.

Q. Mr. Bellville, please discuss the actions taken by I&M that will help to minimize the projected 2014 nuclear fuel costs.

A. The actions taken by I&M to minimize the cost of nuclear fuel occur primarily as part of the long-term planning and competitive bidding processes for nuclear fuel supply to the Cook Nuclear Plant. The Cook Nuclear Plant units are refueled on an 18-month cycle and a reload batch can remain in the reactor for many years; therefore, nuclear fuel cost savings achieved through long-term planning and competitive bidding are realized over a period of years as the fuel is consumed for the production of electricity.

Another way the cost of nuclear fuel is minimized is through the judicious use of the secondary nuclear fuel market. Excess inventories and production capabilities in the nuclear fuel market have made it possible for I&M

to purchase uranium hexafluoride on the secondary market for Cook Nuclear Plant. The uranium hexafluoride purchases have eliminated I&M's carrying costs for uranium during conversion. The logistics of providing the uranium hexafluoride to the enrichment facility are generally accomplished by an accounting transfer of the material, which reduces risk for I&M. Similarly, the enriched uranium is transferred to the fuel fabricator through an accounting transaction, which also reduces risk for I&M.

Yet another example of nuclear fuel cost minimization is the examination, and revision when economically justified, of the fuel loadings that fabricators propose to the Company. Technical evaluations of nuclear fuel cycle designs have also been effective in improving the negotiating position of I&M during the fuel fabrication contract administration. A detailed analysis of a proposed design can show the impact of technical trade-offs made in new products offered by the fabrication vendors. I&M technical staff are involved in the vendor's reload design process so that the design process can occur during or just prior to a refueling outage. This compressed design schedule allows I&M to develop loading patterns that meet the changing energy or regulatory requirements with a minimum impact on fuel cycle economics.

Q. How much uranium does I&M have in inventory?

A. Inventory fluctuates depending on the timing of the reload batch to be delivered. Raw material is obtained to support near-term reloads. Also, small amounts exist as a result of final detailed fuel cycle and fuel assembly design.

I&M continually monitors the performance of any vendor who is under contract to assure fulfillment of contractual obligations. By contracting with reliable and proven performers and continuously monitoring their performance, the Company can operate with confidence at a lower inventory level.

Operating at a relatively low inventory and utilizing the spot market allow I&M to take advantage of the secondary market and reduce fuel-carrying costs. However, a thorough knowledge of uranium market situations is necessary to determine when conditions justify a mid-term or long-term supply contract rather than spot market purchases.

I&M also optimizes the scheduling of purchases to coincide with needs and contract flexibility in order to hold a relatively low inventory. Any additional overage material held is to be promptly used in the next applicable reload and is of minimal impact to the 2014 fuel costs.

Q. How does I&M accomplish the goal of optimized scheduling with minimized inventory and carrying costs?

A. In developing contracts and making purchases, I&M carefully plans the lead time required to perform each phase of fuel processing. The target date from which decisions are made is the date the fabricated fuel is needed at Cook Nuclear Plant. Once the target date is established, it is then necessary to identify when the fabricator must have the enriched uranium. I&M continuously monitors the long term generation schedule and the impacts changes to the generation schedule have on fuel procurement activities.

In addition, when possible, I&M negotiates payment arrangements that will occur as long after performance of the work as reasonably possible. Delaying the time that payment is required directly translates into reduced nuclear fuel costs by reducing carrying costs for a fuel reload.

Q. Are there other actions taken to minimize I&M's fuel cycle costs?

A. Yes. Because the Cook Nuclear Plant is the most economical fuel cost steam plant on the AEP System, both of the Cook Nuclear Plant units are typically base-loaded. Accordingly, I&M's policy is to operate them at a steady state maximum power level unless other operational restrictions apply. Because changes in power level create additional stress on the nuclear fuel assemblies, I&M strives to have these load changes performed as a planned maneuver and at proceduralized and conservative rates of change.

Along these same lines, I&M has developed an extensive capability in neutronic analysis. This allows I&M to develop for the Cook Nuclear Plant an optimized fuel management plan that considers the specific number of fuel assemblies to be loaded each cycle, what their corresponding uranium enrichment should be, which fuel assemblies should be removed from the core during the refueling, and how these new fuel assemblies and those remaining in the core should be rearranged during the refueling. As a result, I&M can meet its energy requirements while at the same time minimizing fuel cycle costs. This is a significant task, and to accomplish it, I&M has developed models of the reactor core utilizing sophisticated computer programs. These models are used to evaluate different reload arrangements proposed by fuel vendors to attain, within certain technical constraints, the goal of meeting I&M's energy requirements and minimizing fuel costs. Through this approach, I&M has been able to develop improved fuel management plans that lower fuel costs.

Q. Is there another area that you can point to that results in minimizing I&M's fuel costs?

A. Yes. The actions of the Company's technical staff to decrease the stress on the fuel during operation of the reactor are complemented by assuring that the fuel assemblies are built in accordance with design requirements. I&M operates under a Nuclear Regulatory Commission - approved Quality Assurance Program that requires the procurement of nuclear fuel from vendors with approved Quality Assurance programs which meet federal regulations. Periodic audits and process surveillances are required for all suppliers to assure that the supplier produces a finished product that fulfills all applicable design and specification criteria. These audits examine aspects of the manufacturing process, including raw materials, details of the design and design control, machined parts, sub-assemblies, components, and the finished fuel assemblies, to assure that corresponding specifications, drawings, and design criteria are met. These Quality Assurance Programs are intended to control the design and manufacturing process to assure a product of the highest quality.

The fuel fabrication contract gives I&M auditors significant authority to reject material at any stage and disqualify a supplier for nonperformance, resulting in a credible threat of contract termination if audit concerns are not addressed in a timely manner. The Quality Assurance Program minimizes fuel cycle cost by eliminating design errors and manufacturing mistakes and ensuring that the final product is capable of fulfilling its intended function.

Q. Have the actions taken by I&M to minimize nuclear fuel costs been effective?

A. Yes.

Q. In your opinion, has I&M made every reasonable effort to acquire nuclear fuel so as to provide electricity to its customers at the lowest nuclear fuel cost possible?

A. Yes.

Q. Does this complete your direct testimony?

A. Yes.

Indiana Michigan Power Company
Cook Unit 1 Monthly Expensing
2014

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2,335.3	2,109.3	2,335.3	2,259.9	2,335.3	2,259.9	2,335.3	2,335.3	1,732.6	602.6	2,259.9	2,335.3	25,236.0
Conv. Factor (BTU/Kwh)	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	
Generation (MBTU)	7,968,259	7,197,137	7,968,259	7,711,218	7,968,259	7,711,218	7,968,259	7,968,259	5,911,934	2,056,325	7,711,218	7,968,259	86,108,601
BTU Charge ($/MBTU)	0.7664	0.7664	0.7664	0.7664	0.7664	0.7664	0.7664	0.7664	0.7664	0.7664	0.7930	0.7930	
Fuel Expense	$ 6,106,873	$ 5,515,886	$ 6,106,873	$ 5,909,877	$ 6,106,873	$ 5,909,877	$ 6,106,873	$ 6,106,873	$ 4,530,906	$ 1,575,967	$ 6,115,081	$ 6,318,917	$ 66,410,879
Monthly Expenses													
Fuel Expense	$ 6,106,873	$ 5,515,886	$ 6,106,873	$ 5,909,877	$ 6,106,873	$ 5,909,877	$ 6,106,873	$ 6,106,873	$ 4,530,906	$ 1,575,967	$ 6,115,081	$ 6,318,917	$ 66,410,879
Post '83 SNF	$ 708,785	$ 640,193	$ 708,785	$ 685,921	$ 687,861	$ 655,548	$ 657,784	$ 659,745	$ 500,161	$ 176,500	$ 760,921	$ 708,785	$ 7,550,990
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Batch 25 MetLife Lease Interest	$ 30,799	$ 30,799	$ 30,799	$ 30,799	$ 16,126	$ 16,126	$ 16,126	$ 16,126	$ 16,126	$ 16,126			$ 219,952
Batch 26 MetLife Lease Interest	$ 64,707	$ 64,707	$ 48,594	$ 48,594	$ 48,594	$ 33,006	$ 33,006	$ 33,006	$ 19,893	$ 19,893	$ 19,893	$ 7,637	$ 441,530
Batch 27 Mizuho Lease Interest	$ 81,487	$ 81,487	$ 71,834	$ 71,834	$ 71,834	$ 62,496	$ 62,496	$ 62,496	$ 52,843	$ 52,843	$ 52,843	$ 46,587	$ 771,080
Total Monthly Expense	$ 7,017,651	$ 6,358,072	$ 6,991,885	$ 6,772,025	$ 6,956,289	$ 6,702,054	$ 6,901,285	$ 6,903,247	$ 5,144,929	$ 1,866,330	$ 6,973,738	$ 7,106,926	$ 75,694,431
Total Monthly Expense w/o SNF	$ 6,308,866	$ 5,717,879	$ 6,283,100	$ 6,086,104	$ 6,268,427	$ 6,046,505	$ 6,243,501	$ 6,243,501	$ 4,644,768	$ 1,689,829	$ 6,212,817	$ 6,398,141	$ 68,143,441
Generation (GWhE)	766.171	692.026	766.171	741.456	743.554	708.624	711.041	713.161	540.656	190.790	741.456	766.171	8,081.278
Mills/KWH	9.159	9.188	9.126	9.133	9.355	9.458	9.706	9.680	9.516	9.782	9.405	9.276	9.367
Mills/KWH w/o SNF	8.234	8.263	8.201	8.208	8.430	8.533	8.781	8.755	8.591	8.857	8.379	8.351	8.432

Indiana Michigan Power Company
Cook Unit 1 Monthly Expensing
2015

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2335.3	2109.3	2335.3	2259.9	2335.3	2259.9	2335.3	2335.3	2259.9	2335.3	2259.9	2335.3	27495.9
Conv. Factor (BTU/Kwh)	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	
Generation (MBTU)	7,968,259	7,197,137	7,968,259	7,711,218	7,968,259	7,711,218	7,968,259	7,968,259	7,711,218	7,968,259	7,711,218	7,968,259	93,819,819
BTU Charge ($/MBTU)	0.7930	0.7930	0.7930	0.7930	0.7930	0.7930	0.7930	0.7930	0.7930	0.7930	0.7930	0.7930	
Fuel Expense	$ 6,318,917	$ 5,707,409	$ 6,318,917	$ 6,115,081	$ 6,318,917	$ 6,115,081	$ 6,318,917	$ 6,318,917	$ 6,115,081	$ 6,318,917	$ 6,115,081	$ 6,318,917	$ 74,400,150
Monthly Expenses													
Fuel Expense	$ 6,318,917	$ 5,707,409	$ 6,318,917	$ 6,115,081	$ 6,318,917	$ 6,115,081	$ 6,318,917	$ 6,318,917	$ 6,115,081	$ 6,318,917	$ 6,115,081	$ 6,318,917	$ 74,400,150
Post '83 SNF	$ 708,785	$ 640,193	$ 708,785	$ 685,921	$ 687,861	$ 655,548	$ 657,784	$ 659,745	$ 652,384	$ 683,938	$ 760,921	$ 708,785	$ 8,210,651
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Batch 26 MetLife Lease Interest	$ 7,637	$ 7,637	$ 6,312	$ 6,312	$ 6,312	$ 5,029	$ 5,029	$ 5,029	$ 6,703	$ 6,703	$ 6,703	$ 2,378	$ 71,784
Batch 27 Mizuho Lease Interest	$ 46,587	$ 46,587	$ 39,794	$ 39,794	$ 39,794	$ 33,223	$ 33,223	$ 33,223	$ 26,430	$ 26,430	$ 26,430	$ 19,637	$ 411,152
Total Monthly Expense	$ 7,106,926	$ 6,426,826	$ 7,098,808	$ 6,872,108	$ 7,077,884	$ 6,833,881	$ 7,039,953	$ 7,041,914	$ 6,825,598	$ 7,060,988	$ 6,934,135	$ 7,074,717	$ 83,393,737
Total Monthly Expense w/o SNF	$ 6,398,141	$ 5,786,633	$ 6,390,023	$ 6,186,187	$ 6,390,023	$ 6,178,333	$ 6,382,169	$ 6,382,169	$ 6,173,214	$ 6,377,050	$ 6,173,214	$ 6,365,932	$ 75,183,086
Generation (GWhE)	766.2	692.0	766.2	741.5	743.6	708.6	711.0	713.2	705.2	739.3	741.5	766.2	8794.3
Mills/KWH	9.276	9.287	9.265	9.268	9.519	9.644	9.901	9.874	9.679	9.551	9.352	9.234	9.483
Mills/KWH w/o SNF	8.351	8.362	8.340	8.343	8.594	8.719	8.976	8.949	8.754	8.626	8.326	8.309	8.549

Indiana Michigan Power Company
Cook Unit 1 Monthly Expensing
2016

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2335.3	2184.6	1657.3	527.3	2335.3	2259.9	2335.3	2335.3	2259.9	2335.3	2259.9	2335.3	25160.6
Conv. Factor (BTU/Kwh)	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	
Generation (MBTU)	7,968,259	7,454,177	5,654,893	1,799,284	7,968,259	7,711,218	7,968,259	7,968,259	7,711,218	7,968,259	7,711,218	7,968,259	85,851,561
BTU Charge ($/MBTU)	0.7930	0.7930	0.7930	0.7930	0.8122	0.8122	0.8122	0.8122	0.8122	0.8122	0.8122	0.8122	
Fuel Expense	$ 6,318,917	$ 5,911,245	$ 4,484,393	$ 1,426,852	$ 6,471,935	$ 6,263,163	$ 6,471,935	$ 6,471,935	$ 6,263,163	$ 6,471,935	$ 6,263,163	$ 6,471,935	$ 69,290,573
Monthly Expenses													
Fuel Expense	$ 6,318,917	$ 5,911,245	$ 4,484,393	$ 1,426,852	$ 6,471,935	$ 6,263,163	$ 6,471,935	$ 6,471,935	$ 6,263,163	$ 6,471,935	$ 6,263,163	$ 6,471,935	$ 69,290,573
Post '83 SNF	$ 708,785	$ 663,057	$ 503,009	$ 160,048	$ 687,861	$ 655,548	$ 657,784	$ 659,745	$ 652,384	$ 683,938	$ 760,921	$ 708,785	$ 7,501,866
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Batch 26 MetLife Lease Interest	$ 2,378	$ 2,378	$ 1,052	$ 1,052	$ 1,052								$ 7,912
Batch 27 Mizuho Lease Interest	$ 19,637	$ 19,637	$ 12,845	$ 12,845	$ 12,845	$ 8,955	$ 8,955	$ 8,955	$ 7,330	$ 7,330	$ 7,330	$ 5,705	$ 132,369
Total Monthly Expense	$ 7,074,717	$ 6,621,317	$ 5,026,298	$ 1,625,797	$ 7,198,694	$ 6,952,666	$ 7,163,674	$ 7,165,636	$ 6,947,877	$ 7,188,204	$ 7,056,414	$ 7,211,425	$ 77,232,720
Total Monthly Expense w/o SNF	$ 6,365,932	$ 5,958,260	$ 4,523,290	$ 1,465,749	$ 6,510,832	$ 6,297,118	$ 6,505,890	$ 6,505,890	$ 6,295,493	$ 6,504,265	$ 6,295,493	$ 6,502,640	$ 69,730,854
Generation (GWhE)	766.171	716.741	543.734	173.006	743.554	708.624	711.041	713.161	705.204	739.313	741.456	766.171	8028.2
Mills/KWH	9.234	9.238	9.244	9.397	9.681	9.812	10.075	10.048	9.852	9.723	9.517	9.412	9.620
Mills/KWH w/o SNF	8.309	8.313	8.319	8.472	8.756	8.886	9.150	9.123	8.927	8.798	8.491	8.487	8.686

Indiana Michigan Power Company
Cook Unit 1 Monthly Expensing
2017

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2335.3	2109.3	2335.3	2259.9	2335.3	2259.9	2335.3	2335.3	1431.3	904.0	2259.9	2335.3	25236.0
Conv. Factor (BTU/Kwh)	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	
Generation (MBTU)	7,968,259	7,197,137	7,968,259	7,711,218	7,968,259	7,711,218	7,968,259	7,968,259	4,883,771	3,084,487	7,711,218	7,968,259	86,108,601
BTU Charge ($/MBTU)	0.8122	0.8122	0.8122	0.8122	0.8122	0.8122	0.8122	0.8122	0.8122	0.8122	0.8244	0.8244	
Fuel Expense	$ 6,471,935	$ 5,845,619	$ 6,471,935	$ 6,263,163	$ 6,471,935	$ 6,263,163	$ 6,471,935	$ 6,471,935	$ 3,966,670	$ 2,505,265	$ 6,356,862	$ 6,568,757	$ 70,129,176
Monthly Expenses													
Fuel Expense	$ 6,471,935	$ 5,845,619	$ 6,471,935	$ 6,263,163	$ 6,471,935	$ 6,263,163	$ 6,471,935	$ 6,471,935	$ 3,966,670	$ 2,505,265	$ 6,356,862	$ 6,568,757	$ 70,129,176
Post '83 SNF	$ 708,785	$ 640,193	$ 708,785	$ 685,921	$ 687,861	$ 655,548	$ 657,784	$ 659,745	$ 413,177	$ 264,750	$ 760,921	$ 708,785	$ 7,552,255
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Batch 27 Mizuho Lease Interest	$ 5,705	$ 5,705	$ 4,080	$ 4,080	$ 4,080	$ 2,508	$ 2,508	$ 2,508	$ 589	$ 589	$ 589		$ 32,941
Total Monthly Expense	$ 7,211,425	$ 6,516,517	$ 7,209,800	$ 6,978,164	$ 7,188,877	$ 6,946,219	$ 7,157,227	$ 7,159,189	$ 4,405,436	$ 2,795,605	$ 7,143,372	$ 7,302,542	$ 78,014,373
Total Monthly Expense w/o SNF	$ 6,502,640	$ 5,876,324	$ 6,501,015	$ 6,292,243	$ 6,501,015	$ 6,290,671	$ 6,499,443	$ 6,499,443	$ 3,992,259	$ 2,530,854	$ 6,382,451	$ 6,593,757	$ 70,462,117
Generation (GWhE)	766.171	692.026	766.171	741.456	743.554	708.624	711.041	713.161	446.629	286.186	741.456	766.171	8082.6
Mills/KWH	9.412	9.417	9.410	9.411	9.668	9.802	10.066	10.039	9.864	9.769	9.634	9.531	9.652
Mills/KWH w/o SNF	8.487	8.491	8.485	8.486	8.743	8.877	9.141	9.114	8.939	8.843	8.608	8.606	8.718

Indiana Michigan Power Company
Cook Unit 1 Monthly Expensing
2018

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2335.3	2109.3	2335.3	2259.9	2335.3	2259.9	2335.3	2335.3	2259.9	2335.3	2259.9	2335.3	27495.9
Conv. Factor (BTU/Kwh)	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	3412.1	
Generation (MBTU)	7,968,259	7,197,137	7,968,259	7,711,218	7,968,259	7,711,218	7,968,259	7,968,259	7,711,218	7,968,259	7,711,218	7,968,259	93,819,819
BTU Charge ($/MBTU)	0.8244	0.8244	0.8244	0.8244	0.8244	0.8244	0.8244	0.8244	0.8244	0.8244	0.8244	0.8244	
Fuel Expense	$ 6,568,757	$ 5,933,071	$ 6,568,757	$ 6,356,862	$ 6,568,757	$ 6,356,862	$ 6,568,757	$ 6,568,757	$ 6,356,862	$ 6,568,757	$ 6,356,862	$ 6,568,757	$ 77,341,817
Monthly Expenses													
Fuel Expense	$ 6,568,757	$ 5,933,071	$ 6,568,757	$ 6,356,862	$ 6,568,757	$ 6,356,862	$ 6,568,757	$ 6,568,757	$ 6,356,862	$ 6,568,757	$ 6,356,862	$ 6,568,757	$ 77,341,817
Post '83 SNF	$ 708,785	$ 640,193	$ 708,785	$ 685,921	$ 687,861	$ 655,548	$ 657,784	$ 659,745	$ 652,384	$ 683,938	$ 760,921	$ 708,785	$ 8,210,651
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Total Monthly Expense	$ 7,302,542	$ 6,598,264	$ 7,302,542	$ 7,067,783	$ 7,281,618	$ 7,037,410	$ 7,251,541	$ 7,253,502	$ 7,034,246	$ 7,277,695	$ 7,142,783	$ 7,302,542	$ 85,852,468
Total Monthly Expense w/o SNF	$ 6,593,757	$ 5,958,071	$ 6,593,757	$ 6,381,862	$ 6,593,757	$ 6,381,862	$ 6,593,757	$ 6,593,757	$ 6,381,862	$ 6,593,757	$ 6,381,862	$ 6,593,757	$ 77,641,817
Generation (GWhE)	766.171	692.026	766.171	741.456	743.554	708.624	711.041	713.161	705.204	739.313	741.456	766.171	8794.3
Mills/KWH	9.531	9.535	9.531	9.532	9.793	9.931	10.198	10.171	9.975	9.844	9.633	9.531	9.762
Mills/KWH w/o SNF	8.606	8.610	8.606	8.607	8.868	9.006	9.273	9.246	9.050	8.919	8.607	8.606	8.829

Indiana Michigan Powr Company
Cook Unit 2 Monthly Expensing
2014

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2,451.2	2,214.0	2,451.2	2,372.1	2,451.2	2,372.1	2,451.2	2,451.2	2,372.1	2,451.2	2,372.1	2,451.2	28,860.7
Conv. Factor (BTU/Kwh)	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	
Generation (MBTU)	8,363,778	7,554,380	8,363,778	8,093,978	8,363,778	8,093,978	8,363,778	8,363,778	8,093,978	8,363,778	8,093,978	8,363,778	98,476,735
BTU Charge ($/MBTU)	0.6966	0.6966	0.6966	0.6966	0.6966	0.6966	0.6966	0.6966	0.6966	0.6966	0.6966	0.6966	
Fuel Expense	$ 5,826,166	$ 5,262,344	$ 5,826,166	$ 5,638,225	$ 5,826,166	$ 5,638,225	$ 5,826,166	$ 5,826,166	$ 5,638,225	$ 5,826,166	$ 5,638,225	$ 5,826,166	$ 68,598,408
Monthly Expenses													
Fuel Expense	$ 5,826,166	$ 5,262,344	$ 5,826,166	$ 5,638,225	$ 5,826,166	$ 5,638,225	$ 5,826,166	$ 5,826,166	$ 5,638,225	$ 5,826,166	$ 5,638,225	$ 5,826,166	$ 68,598,408
Post '83 SNF	$ 723,824	$ 653,776	$ 723,824	$ 700,475	$ 715,977	$ 682,757	$ 688,515	$ 693,092	$ 680,226	$ 719,247	$ 775,475	$ 723,824	$ 8,481,012
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Batch 21 DCC III Lease Interest	$ 20,002	$ 17,647	$ 16,768	$ 15,905	$ 15,048	$ 14,187	$ 13,316	$ 12,431	$ 11,414	$ 10,491	$ 9,546	$ 8,579	$ 165,335
Batch 22 Lease Interest	$ 87,410	$ 78,023	$ 78,023	$ 78,023	$ 63,110	$ 63,110	$ 63,110	$ 48,034	$ 48,034	$ 48,034	$ 32,795	$ 32,795	$ 720,501
Total Monthly Expense	$ 6,682,402	$ 6,036,790	$ 6,669,781	$ 6,457,628	$ 6,645,302	$ 6,423,280	$ 6,616,108	$ 6,604,724	$ 6,402,899	$ 6,628,938	$ 6,481,041	$ 6,616,364	$ 78,265,256
Total Monthly Expense w/o SNF	$ 5,958,578	$ 5,383,014	$ 5,945,957	$ 5,757,154	$ 5,929,324	$ 5,740,523	$ 5,927,592	$ 5,911,631	$ 5,722,673	$ 5,909,691	$ 5,705,566	$ 5,892,540	$ 69,784,244
Generation (GWhE)	782.428	706.709	782.428	757.188	773.946	738.036	744.260	749.208	735.300	777.480	757.188	782.428	9,086.598
Mills/KWH	8.541	8.542	8.524	8.528	8.586	8.703	8.890	8.816	8.708	8.526	8.559	8.456	8.613
Mills/KWH w/o SNF	7.616	7.617	7.599	7.603	7.661	7.778	7.964	7.891	7.783	7.601	7.535	7.531	7.680

Indiana Michigan Powr Company
Cook Unit 2 Monthly Expensing
2015

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2,451.2	2,214.0	1,897.7	553.5	2,451.2	2,372.1	2,451.2	2,451.2	2,372.1	2,451.2	2,372.1	2,451.2	26,488.6
Conv. Factor (BTU/Kwh)	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	
Generation (MBTU)	8,363,778	7,554,380	6,475,183	1,888,595	8,363,778	8,093,978	8,363,778	8,363,778	8,093,978	8,363,778	8,093,978	8,363,778	90,382,757
BTU Charge ($/MBTU)	0.6966	0.6966	0.6966	0.6966	0.7285	0.7285	0.7285	0.7285	0.7285	0.7285	0.7285	0.7285	
Fuel Expense	$ 5,826,166	$ 5,262,344	$ 4,510,580	$ 1,315,586	$ 6,093,121	$ 5,896,569	$ 6,093,121	$ 6,093,121	$ 5,896,569	$ 6,093,121	$ 5,896,569	$ 6,093,121	$ 65,069,989
Monthly Expenses													
Fuel Expense	$ 5,826,166	$ 5,262,344	$ 4,510,580	$ 1,315,586	$ 6,093,121	$ 5,896,569	$ 6,093,121	$ 6,093,121	$ 5,896,569	$ 6,093,121	$ 5,896,569	$ 6,093,121	$ 65,069,989
Post '83 SNF	$ 723,824	$ 653,776	$ 560,380	$ 163,444	$ 715,977	$ 682,757	$ 688,515	$ 693,092	$ 680,226	$ 719,247	$ 775,475	$ 723,824	$ 7,780,537
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Batch 21 DCC III Lease Interest	$ 7,589	$ 6,576	$ 5,538	$ 4,477	$ 3,391	$ 2,280	$ 1,154	$ -	$ -	$ -	$ -	$ -	$ 31,005
Batch 22 Lease Interest	$ 32,795	$ 17,557	$ 17,557	$ 17,557	$ 3,781	$ 3,781	$ 3,781	$ 3,291	$ 3,291	$ 3,291	$ 2,638	$ 2,638	$ 111,958
Total Monthly Expense	$ 6,615,374	$ 5,965,253	$ 5,119,055	$ 1,526,064	$ 6,841,271	$ 6,610,387	$ 6,811,571	$ 6,814,505	$ 6,605,086	$ 6,840,659	$ 6,699,682	$ 6,844,583	$ 73,293,490
Total Monthly Expense w/o SNF	$ 5,891,550	$ 5,311,476	$ 4,558,675	$ 1,362,620	$ 6,125,293	$ 5,927,630	$ 6,123,056	$ 6,121,412	$ 5,924,860	$ 6,121,412	$ 5,924,207	$ 6,120,759	$ 65,512,953
Generation (GWhE)	782.428	706.709	605.750	176.677	773.946	738.036	744.260	749.208	735.300	777.480	757.188	782.428	8,329.410
Mills/KWH	8.455	8.441	8.451	8.638	8.839	8.957	9.152	9.096	8.983	8.799	8.848	8.748	8.799
Mills/KWH w/o SNF	7.530	7.516	7.526	7.712	7.914	8.032	8.227	8.171	8.058	7.873	7.824	7.823	7.865

Indiana Michigan Powr Company
Cook Unit 2 Monthly Expensing
2016

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2,451.2	2,293.0	2,451.2	2,372.1	2,451.2	2,372.1	2,451.2	2,451.2	2,372.1	316.3	1,186.1	2,451.2	25,618.8
Conv. Factor (BTU/Kwh)	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	
Generation (MBTU)	8,363,778	7,824,179	8,363,778	8,093,978	8,363,778	8,093,978	8,363,778	8,363,778	8,093,978	1,079,197	4,046,989	8,363,778	87,414,965
BTU Charge ($/MBTU)	0.7285	0.7285	0.7285	0.7285	0.7285	0.7285	0.7285	0.7285	0.7285	0.7285	0.8363	0.8363	
Fuel Expense	$ 6,093,121	$ 5,700,017	$ 6,093,121	$ 5,896,569	$ 6,093,121	$ 5,896,569	$ 6,093,121	$ 6,093,121	$ 5,896,569	$ 786,209	$ 3,384,576	$ 6,994,790	$ 65,020,904
Monthly Expenses													
Fuel Expense	$ 6,093,121	$ 5,700,017	$ 6,093,121	$ 5,896,569	$ 6,093,121	$ 5,896,569	$ 6,093,121	$ 6,093,121	$ 5,896,569	$ 786,209	$ 3,384,576	$ 6,994,790	$ 65,020,904
Post '83 SNF	$ 723,824	$ 677,125	$ 723,824	$ 700,475	$ 715,977	$ 682,757	$ 688,515	$ 693,092	$ 680,226	$ 92,806	$ 441,057	$ 756,517	$ 7,576,195
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Batch 22 Lease Interest	$ 2,638	$ 1,984	$ 1,984	$ 1,984	$ 1,338	$ 1,338	$ 1,338	$ 692	$ 692	$ 692			$ 14,680
Total Monthly Expense	$ 6,844,583	$ 6,404,126	$ 6,843,929	$ 6,624,028	$ 6,835,437	$ 6,605,664	$ 6,807,975	$ 6,811,906	$ 6,602,487	$ 904,707	$ 3,850,632	$ 7,776,306	$ 72,911,780
Total Monthly Expense w/o SNF	$ 6,120,759	$ 5,727,001	$ 6,120,105	$ 5,923,553	$ 6,119,459	$ 5,922,907	$ 6,119,459	$ 6,118,813	$ 5,922,261	$ 811,901	$ 3,409,576	$ 7,019,790	$ 65,335,584
Generation (GWhE)	782.428	731.948	782.428	757.188	773.946	738.036	744.260	749.208	735.300	100.320	395.694	817.768	8,108.524
Mills/KWH	8.748	8.749	8.747	8.748	8.832	8.950	9.147	9.092	8.979	9.018	9.731	9.509	8.992
Mills/KWH w/o SNF	7.823	7.824	7.822	7.823	7.907	8.025	8.222	8.167	8.054	8.093	8.617	8.584	8.058

Indiana Michigan Powr Company
Cook Unit 2 Monthly Expensing
2017

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2,451.2	2,214.0	2,451.2	2,372.1	2,451.2	2,372.1	2,451.2	2,451.2	2,372.1	2,451.2	2,372.1	2,451.2	28,860.7
Conv. Factor (BTU/Kwh)	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	
Generation (MBTU)	8,363,778	7,554,380	8,363,778	8,093,978	8,363,778	8,093,978	8,363,778	8,363,778	8,093,978	8,363,778	8,093,978	8,363,778	98,476,735
BTU Charge ($/MBTU)	0.8363	0.8363	0.8363	0.8363	0.8363	0.8363	0.8363	0.8363	0.8363	0.8363	0.8363	0.8363	
Fuel Expense	$ 6,994,790	$ 6,317,875	$ 6,994,790	$ 6,769,151	$ 6,994,790	$ 6,769,151	$ 6,994,790	$ 6,994,790	$ 6,769,151	$ 6,994,790	$ 6,769,151	$ 6,994,790	$ 82,358,007
Monthly Expenses													
Fuel Expense	$ 6,994,790	$ 6,317,875	$ 6,994,790	$ 6,769,151	$ 6,994,790	$ 6,769,151	$ 6,994,790	$ 6,994,790	$ 6,769,151	$ 6,994,790	$ 6,769,151	$ 6,994,790	$ 82,358,007
Post '83 SNF	$ 756,517	$ 683,306	$ 756,517	$ 732,113	$ 748,670	$ 714,396	$ 721,208	$ 725,785	$ 711,864	$ 751,940	$ 807,113	$ 756,517	$ 8,865,946
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Total Monthly Expense	$ 7,776,306	$ 7,026,180	$ 7,776,306	$ 7,526,264	$ 7,768,460	$ 7,508,547	$ 7,740,998	$ 7,745,575	$ 7,506,016	$ 7,771,729	$ 7,601,264	$ 7,776,306	$ 91,523,953
Total Monthly Expense w/o SNF	$ 7,019,790	$ 6,342,875	$ 7,019,790	$ 6,794,151	$ 7,019,790	$ 6,794,151	$ 7,019,790	$ 7,019,790	$ 6,794,151	$ 7,019,790	$ 6,794,151	$ 7,019,790	$ 82,658,007
Generation (GWhE)	817.768	738.629	817.768	791.388	809.286	772.236	779.600	784.548	769.500	812.820	791.388	817.768	9,502.698
Mills/KWH	9.509	9.512	9.509	9.510	9.599	9.723	9.929	9.873	9.754	9.561	9.605	9.509	9.631
Mills/KWH w/o SNF	8.584	8.587	8.584	8.585	8.674	8.798	9.004	8.948	8.829	8.636	8.585	8.584	8.698

Indiana Michigan Powr Company
Cook Unit 2 Monthly Expensing
2018

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Fuel Expense													
Net Generation (GWhT)	2,451.2	2,214.0	2,134.9	316.3	2,451.2	2,372.1	2,451.2	2,451.2	2,372.1	2,451.2	2,372.1	2,451.2	26,488.6
Conv. Factor (BTU/Kwh)	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	3,412.1	
Generation (MBTU)	8,363,778	7,554,380	7,284,580	1,079,197	8,363,778	8,093,978	8,363,778	8,363,778	8,093,978	8,363,778	8,093,978	8,363,778	90,382,757
BTU Charge ($/MBTU)	0.8363	0.8363	0.8363	0.8553	0.8553	0.8553	0.8553	0.8553	0.8553	0.8553	0.8553	0.8553	
Fuel Expense	$ 6,994,790	$ 6,317,875	$ 6,092,236	$ 923,055	$ 7,153,675	$ 6,922,912	$ 7,153,675	$ 7,153,675	$ 6,922,912	$ 7,153,675	$ 6,922,912	$ 7,153,675	$ 76,865,066
Monthly Expenses													
Fuel Expense	$ 6,994,790	$ 6,317,875	$ 6,092,236	$ 923,055	$ 7,153,675	$ 6,922,912	$ 7,153,675	$ 7,153,675	$ 6,922,912	$ 7,153,675	$ 6,922,912	$ 7,153,675	$ 76,865,066
Post '83 SNF	$ 756,517	$ 683,306	$ 658,902	$ 97,615	$ 748,670	$ 714,396	$ 721,208	$ 725,785	$ 711,864	$ 751,940	$ 807,113	$ 756,517	$ 8,133,833
Fuel Reload Engineering	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 25,000	$ 300,000
Total Monthly Expense	$ 7,776,306	$ 7,026,180	$ 6,776,138	$ 1,045,670	$ 7,927,346	$ 7,662,307	$ 7,899,884	$ 7,904,461	$ 7,659,776	$ 7,930,615	$ 7,755,025	$ 7,935,192	$ 85,298,899
Total Monthly Expense w/o SNF	$ 7,019,790	$ 6,342,875	$ 6,117,236	$ 948,055	$ 7,178,675	$ 6,947,912	$ 7,178,675	$ 7,178,675	$ 6,947,912	$ 7,178,675	$ 6,947,912	$ 7,178,675	$ 77,165,066
Generation (GWhE)	817.768	738.629	712.249	105.518	809.286	772.236	779.600	784.548	769.500	812.820	791.388	817.768	8,711.310
Mills/KWH	9.509	9.512	9.514	9.910	9.795	9.922	10.133	10.075	9.954	9.757	9.799	9.703	9.792
Mills/KWH w/o SNF	8.584	8.587	8.589	8.985	8.870	8.997	9.208	9.150	9.029	8.832	8.779	8.778	8.858

DIRECT TESTIMONY OF CHARLES F. WEST
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY
2014 PSCR PLAN CASE

Q. Please state your name, position, and business address.

A. My name is Charles F. West. I am Manager, Fuel Procurement, in the Fuel, Emissions and Logistics Department for American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP). My business address is 155 West Nationwide Boulevard, Suite 500, Columbus, Ohio 43215.

Q. What are your primary areas of responsibility as Manager, Fuel Procurement, for AEPSC?

A. I am responsible for managing coal procurement, contract oversight, and inventory monitoring activities for AEP operating companies, Indiana Michigan Power Company (I&M), Southwestern Electric Power Company (SWEPCO), Public Service Company of Oklahoma (PSO), and Appalachian Power Company (APCo). I am also a fuel procurement agent on behalf of Ohio Valley Electric Corporation and Indiana Kentucky Electric Corporation.

Q. Please briefly describe your educational background.

A. I graduated from Queen's University in Kingston, Ontario, Canada in 1978 with a degree in Mining Engineering and I later obtained my Professional Engineer license in the State of Washington.

Q. Please describe your professional background.

A. After graduation in 1978, I was employed in the mining industry by Cleveland Cliffs Iron Company in Michigan and later by Quintette Coal Company in British Columbia. I then spent over seven years employed by

PacifiCorp in various engineering and management positions at coal mining operations in Washington State and Wyoming and at their headquarters in Salt Lake City, Utah. In 1995, I accepted a position as Coal Buyer for Central and Southwest Corporation (CSW), a utility holding company in Dallas, Texas. I transferred to Columbus, Ohio as a Coal Buyer after CSW's merger with AEP in 2000. In 2003, I joined Reliant Energy Inc. in Canonsburg, PA as a Senior Fuels Specialist. In 2005, I returned to AEP as a Coordinator in the Fuels, Emissions and Logistics department. I was promoted to Manager of Cook Coal Terminal in Metropolis, IL in 2007 and accepted my current position in January of 2009.

Q. Have you previously filed testimony before this Commission or other Commissions?

A. Yes. I have submitted testimony to the Michigan Public Service Commission and the Indiana Utility Regulatory Commission on behalf of I&M, and the Public Service Commission of West Virginia on behalf of APCo. In addition, I have submitted testimony to the Public Utility Commission of Texas on behalf of SWEPCO and the Oklahoma Corporation Commission on behalf of PSO.

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

A. The purpose of my testimony in this proceeding is to:

(1) Provide a summary of I&M's long-term supply agreements;

(2) Submit a short-term forecast of delivered coal prices for the calendar year 2014;

(3) Submit a five-year forecast of projected delivered coal prices;

(4) Discuss I&M's coal purchasing strategy; and

(5) Discuss market conditions affecting I&M's fuel costs.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring two exhibits:

(1) Exhibit IM-12 (CFW-1) titled "Indiana Michigan Power Company Coal Cost Forecast 2014", which provides a forecast of the monthly delivered coal costs for I&M's generating stations in 2014; and

(2) Exhibit IM-13 (CFW-2) titled "Indiana Michigan Power Company Five-Year Coal Cost Forecast", which provides a forecast of annual delivered coal costs for each I&M generating station from 2014 through 2018.

Q. Please describe the role of AEPSC in I&M's fuel procurement process.

A. AEPSC, acting as agent for all of the electric utility operating companies of AEP System, including I&M, is responsible for the procurement and delivery of coal to the Company's generating stations, as well as establishing coal inventory target level ranges and managing those levels.

AEPSC's primary objective is to assure a continuous supply of coal of the appropriate quality to all of AEP's coal generating stations, delivered at the lowest reasonable cost over a period of years so as to promote the generation of the lowest cost per kWh of electricity, within the constraints of safety, reliability of supply, and environmental requirements.

Coal deliveries must be arranged so that sufficient coal is available at all times in order to provide and maintain adequate and dependable electric service for the customer. The quality of the delivered coal, in addition to the consistency of the sulfur content, is fundamental to I&M in achieving and maintaining compliance with the applicable environmental limitations and operating efficiencies.

Q. Please identify and describe I&M's coal generating stations.

A. I&M has two coal generating stations, Rockport and Tanners Creek, that are both projected to be in operation during 2014.

The Rockport generating station, located in Spencer County, Indiana, consists of two 1300-megawatt coal generating units. Sulfur dioxide (SO_2) emissions at Rockport are limited by the New Source Performance Standard to 1.2 lbs. SO_2 per Million British Thermal Unit (MMBtu). Compliance with the emission limit is achieved by using a blend consisting primarily of low-sulfur subbituminous coal in the steam generators. The coal supply for Rockport currently uses a blend of Powder River Basin (PRB) coal from Wyoming and low-sulfur bituminous coal from Colorado and various eastern sources.

The Tanners Creek generating station is located in Dearborn County, Indiana, and consists of four coal units with a total nominal capacity of 995 megawatts. Units 1, 2, and 3 (TC 1-3) are limited to SO_2 emissions of 1.2 lbs. SO_2/MMBtu and Unit 4 (TC 4) has been modified to a 1.2% sulfur standard on an annual basis. As a result of the different air emission standards, as well as differences in the boiler designs, the coal supplies for TC 1-3 and TC 4 vary in order to meet the differing coal quality requirements of the units. The fuel requirements of TC 1-3 will be met from bituminous sources located in Colorado and/or from eastern bituminous sources. TC 4, similar to Rockport, can use a blend of subbituminous and bituminous coals.

Q. Please summarize the contracts forecasted to be used to supply coal in 2014.

A. The summary below contains information on the contracts under which I&M expects to receive coal during the calendar year 2014. The first column lists the suppliers represented by consecutive letters. A letter is used in lieu of a name in order to maintain the confidentiality of individual suppliers. The second column identifies the type of coal. Western coal typically originates in the Power River Basin in Wyoming while Eastern coal can originate from a variety of eastern sources. The third column represents the contractual start and end period (month and year). The fourth and final column displays the tons I&M expects to receive under each contract in 2014. Tons can be received directly into one of the plants, or received at the Cook Coal Terminal and transferred to the plant when needed.

Supplier	Coal Type	Term	2014 Tons
A	Western	Dec 04 - Dec 14	1,875,000
B	Western	Dec 04 - Dec 16	4,000,000
C	Eastern	Jun 08 - Dec 14	90,000

Q. Please provide a summary of I&M's anticipated coal supplies and costs.

A. The majority of I&M's need for coal during 2014 will be supplied by long-term coal contracts that have been in place for several years.

In addition to the above mentioned long-term contracts, coal may also be purchased to fulfill any additional supply requirements through both long term and spot agreements with various other suppliers. I&M expects to receive approximately 7.8 million tons of coal in 2014 at the Rockport plant at a projected weighted average delivered cost of 202.75 cents/MMBtu (exclusive of affiliated transportation costs).

I&M expects to receive approximately 448,000 tons of coal in 2014 at TC 1-3 at a projected weighted average delivered cost 302.69 cents/MMBtu (exclusive of affiliate transportation costs).

I&M expects to receive approximately 1.2 million tons of coal in 2014 at TC 4 at a projected weighted average delivered cost of 197.80 cents/MMBtu (exclusive of affiliate transportation costs).

All of the forecasted deliveries and costs, as discussed above, are supported by Exhibit IM-12 (CFW-1) and were provided to Witness Riley for use in preparing I&M's forecast.

Q. What is the anticipated overall cost of coal delivered to I&M plants in 2014?

A. As shown in Exhibit IM-12 (CFW-1), the anticipated overall cost of coal delivered to I&M plants in 2014 is 208.18 cents/MMBTU or $38.75 per ton (exclusive of affiliate transportation costs).

Q. How were the forecasted deliveries and prices determined?

A. The amount of coal projected to be consumed was based on load forecasts for the applicable years. Coal delivery requirements were then determined by taking into consideration coal inventory, the forecast of coal consumption, and adjustments for any contingencies that would necessitate an increase or decrease in coal inventory levels.

Next, the sources of the coal were determined by taking into account environmental and boiler constraints, as well as, contractual obligations and existing sources of supply. The price of contract coal and committed spot market purchases are based on contractual agreements. The prices of coal purchases not yet committed were estimated based on AEPSC's market knowledge.

Finally, transportation costs were forecasted based on an estimate of the rates under the rail contract with Union Pacific to deliver western coal to the Cook Coal Terminal that became effective on January 1, 2013.

Q. Please describe I&M's coal purchasing strategy.

A. I&M's coal purchasing strategy is based on continuous market monitoring and evaluation along with periodic competitive bids. After I&M's uncommitted needs for coal during the upcoming year are estimated, coal producers are contacted and given the parameters for the amount and quality of coal that is sought. From bid results and/or existing opportunities, if reasonable, I&M then makes its selection of the coals needed to meet its requirements based primarily on price and coal quality considerations.

Q. How are market conditions affecting I&M's fuel costs?

A. The unstable economy continues to provide challenges for predicting coal consumption and has had a significant impact on coal procurement.

However, weather, natural gas prices, and environmental impositions have had the largest impact on the demand for, and cost of, coal for I&M.

In an effort to adjust to a down market due to low natural gas prices, pending regulations, and other factors, coal producers idled mines and cut production in the fourth quarter of 2012. In fact, coal production during the last quarter of 2012 reached the lowest fourth quarter level in more than 15 years (US Energy Information Administration (EIA) Quarterly Coal Report: October – December 2012).

The national trend of decreased coal production continued into 2013; coal production during the first quarter was about 1.8% lower than the previous quarter and 8% lower than the first quarter of 2012 (EIA Quarterly Coal Report: January – March 2013). While coal suppliers have decreased production to meet the reduced levels of demand, generating stations that burn coal generally are experiencing higher inventory compared to historical averages. This continues to have an impact on the short-term coal market, but is not expected to significantly affect the long-term market prices.

In addition to these conditions, the US Environmental Protection Agency (EPA), on July 6, 2011, released the Cross-state Air Pollution Rule (CSAPR). Under CSAPR, reductions in emissions were to begin as early as January 1, 2012. However, on December 30, 2011, the US Court of Appeals for the District of Columbia Circuit issued a stay of CSAPR which delayed the implementation of the rules set to begin January 1, 2012. The court later, on August 21, 2012, decided to vacate the rule and instructed the EPA to continue administering the Clean Air Interstate Rule pending the EPA's promulgation of a valid replacement. The EPA appealed this decision and on June 24, 2013, the US Supreme Court announced it would consider the EPA's appeal during its 2013/2014 term. This regulatory uncertainty continues to contribute to, or impact, the price differential for the ultra-low sulfur PRB (0.55 lbs. SO_2/MMBtu). At this time, we do not anticipate this new ruling will have a significant impact on I&M's generation plans beyond 2014, but I&M will continue to monitor the evolving regulatory and legal environment. Beginning in 2015, Mercury and Air Toxics Standards (MATS) will introduce new constraints. The expected impact of MATS is reflected in Exhibit IM-13 (CFW-2), particularly in 2015 when Tanners Creek is shut down and when Rockport will experience decreased burn while efforts are made to install environmental controls.

Despite these conditions, there is less risk in the projection of I&M's delivered coal prices in 2014 as much of the prices are currently locked in under long-term contracts. Based on current market projections, I&M may expect to pay between \$11/ton and \$13/ton for PRB coal and between \$62/ton and \$73/ton for bituminous coal in 2014.

Q. Is risk assessment an important factor in I&M's coal purchasing decision?

A. Yes. The Company considers a vendor's financial status, ability to deliver, and past performance when evaluating its decision to do business with that supplier. Purchases from reliable creditworthy vendors serve to enhance I&M's security of supply.

Q. Do you have an opinion regarding the reasonableness of I&M's coal costs?

A. Yes. I&M has and continues to aggressively pursue and manage its coal supply and transportation costs, recognizing and addressing opportunities to provide a reliable supply of coal at the lowest cost reasonably possible.

Q. Does this conclude your direct testimony?

A. Yes.

Indiana Michigan Power Company
Monthly Coal Cost Forecast
For the Year 2014

	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Total
Rockport													
Tons (000)	751	756	734	582	352	638	645	696	639	677	580	706	7,756
¢/MMBTU	200.33	201.71	202.78	202.19	201.68	202.26	203.76	202.95	202.99	204.85	203.12	204.20	202.75
Tanners 1-3													
Tons (000)	73	28	33	37	18	25	69	68	36	39	15	7	448
¢/MMBTU	308.46	288.92	293.17	296.13	271.17	285.13	307.67	307.54	295.71	320.83	320.83	320.83	302.69
Tanners 4													
Tons (000)	126	126	-	-	87	112	149	149	131	125	124	112	1,241
¢/MMBTU	196.22	196.76	0.00	0.00	196.68	197.10	197.38	197.79	198.49	198.90	199.03	199.51	197.80
I&M Total													
Tons (000)	950	910	767	619	457	775	863	913	806	841	719	825	9,445
¢/MMBTU	210.36	204.50	207.76	209.38	204.28	204.98	213.14	212.03	207.56	210.86	205.58	204.88	208.18

Slight variances due to rounding

Exhibit IM-13 (CFW-2)

Indiana Michigan Power Company
Five Year Annual Coal Cost Forecast
For the Years of 2014 Through 2018

	2014	2015	2016	2017	2018
Rockport					
Tons (000)	7,756	6,344	9,082	8,628	8,540
¢/MMBTU	202.75	215.19	220.18	226.04	230.74
Tanners Creek 1-3					
Tons (000)	448	43	-	-	-
¢/MMBTU	302.69	325.00	0.00	0.00	0.00
Tanners Creek 4					
Tons (000)	1,241	235	-	-	-
¢/MMBTU	197.80	209.95	0.00	0.00	0.00
I&M Total					
Tons (000)	9,445	6,622	9,082	8,628	8,540
¢/MMBTU	208.18	215.90	220.18	226.04	230.74

Slight variances due to rounding

DIRECT TESTIMONY OF RICHARD A. RILEY
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY
2014 PSCR PLAN CASE

Q. Would you please state your name and business address?

A. My name is Richard A. Riley, and my business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. By whom are you employed and what is your position?

A. I am employed by the American Electric Power Service Corporation (AEPSC) as a Staff Financial Analyst Coordinator. AEPSC supplies engineering, financing, accounting, and similar planning and advisory services to the ten electric operating companies of the American Electric Power System including Indiana Michigan Power Company (I&M or Company).

Q. Would you please describe your educational and professional background?

A. Yes. I received a Bachelor of Science Degree in Business Management from The Ohio State University in 1982. I earned a Certified Public Accountant Certificate in 1982 and the designation of Certified Internal Auditor in 1988. In 1997, I completed the AEP Management Development program at The Ohio State University.

I was employed by AEPSC in February 1987 as an internal auditor. After reaching the position of Senior Auditor, I transferred to the Corporate Planning and Budgeting Department in 1995 as a Financial Analyst. In July 1999, I left AEPSC to pursue an employment opportunity outside the utility industry. In July 2007, I re-joined AEPSC as a Financial Analyst and have held various positions with increasing levels of responsibility within that group. In February 2013, I was named to my current position.

Q. What are your responsibilities as a Staff Financial Analyst Coordinator?

A. I am primarily responsible for the supervision of the financial forecasting and analysis of the AEP System's ten electric operating companies including I&M. In this capacity, I coordinate short- and long-term forecasts for these companies as well as monthly analysis of budget to actual variances. With respect to this filing, I am responsible for the derivation of the Power Supply Cost Recovery (PSCR) fuel data for the forecast periods.

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes. I have submitted testimony on behalf of I&M before the Michigan Public Service Commission (MPSC or the Commission) in the Company's most recent base rate filing, (Case U-16801) and before the Indiana Utility Regulatory Commission in various fuel and other rider cost proceedings. I have also submitted testimony on behalf of Appalachian Power Company in its Expanded Net Energy Cost proceedings before the West Virginia Public Service Commission.

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

A. The purpose of my testimony is to present the forecasts of the Company's monthly power supply costs and net energy requirements for the period January 2014 through December 2014 and, in accordance with Commission requirements, provide similar data on an annual basis for the years 2014 through 2018. I will also describe the methodologies employed to derive I&M's estimated power supply costs.

Q. Have the data you are sponsoring been prepared in a manner generally consistent with previous I&M PSCR Plan filings and modified for the Commission Orders in Case U-16433 and Case U-16801?

A. Yes. I have prepared data consistent with previous PSCR Plan filings, with the modifications from Commission Orders in Case U-16433 and Case U-16801 included.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibits:

- Exhibit IM-14 (RAR-1) that identifies, by component, the forecasted monthly Total Company - Michigan Basis power supply costs for the period January 1, 2014 through December 31, 2014.
- Exhibit IM-15 (RAR-2) that details the forecasted monthly Total Company - Michigan Basis net energy requirement for the period January 1, 2014 through December 31, 2014.
- Exhibit IM-16 (RAR-3) that identifies, by component, the annual forecasted Total Company - Michigan Basis power supply costs for the years 2014 through 2018.
- Exhibit IM-17 (RAR-4) that details the forecasted annual Total Company - Michigan Basis net energy requirement for the

years 2014 through 2018.

Q. What are the power supply costs you address?

A. Power supply costs, as shown on Exhibits IM-14 (RAR-1) and IM-16 (RAR-3), reflect those costs allowable under the terms of I&M's PSCR clause adopted pursuant to Act 304 of the Public Acts of 1982, and the methodologies in this PSCR Plan are consistent with the PSCR basing point included in the Commission Order in Case U-16801.

The costs included in the determination of the total power supply cost include all items in accounts 447 and 555 except those related to Indiana jurisdictional trackers and revenues directly related to I&M’s wholesale requirements customers. There are also a few items that are not in accounts 447 and 555 that are related to Off-System Sales (OSS) margins that have been included in the development of I&M's Total Company – Michigan Basis PSCR factor.

Q. Please identify the 447 and 555 accounts related to Indiana jurisdictional trackers and revenues directly related to I&M’s wholesale requirements customers that have been excluded in the development of I&M's Total Company – Michigan Basis PSCR factor.

A. The 447 and 555 accounts that were excluded in the development of I&M's Total Company – Michigan Basis PSCR factor are provided in the following table.

Account	Description
4470027	Wholesale/Municipal/Public Authority Fuel Revenue
4470033	Wholesale/Municipal/Public Authority Base Revenue
4470150	Trans Revenue - Dedicated Wholesale/Municipal
4470171	Over-Under OSS Margin Sharing – Indiana
4470172	Over-recovered PJM Expense – Indiana
4470183	Over-recovered Capacity - IN
5550106	Under-recovered PJM Expense – Indiana
5550119	Under-recovered Capacity - IN

Q. Would you please provide a general description of the methodologies and assumptions utilized in the development of I&M's Total Company - Michigan Basis PSCR costs for the period 2014 through 2018?

A. A discussion of the specific methodologies and assumptions used in the derivation of each of these items by category follows. As Witness MacLean discusses, the forecast reflects the dissolution of the AEP Pool January 1, 2014 and that I&M will operate on a stand-alone basis for the period 2014 through 2018.

<u>Fossil Fuel Expense</u>

Q. Would you please describe how the cost of fossil fuel consumed was calculated?

A. Yes. The cost of fossil fuel consumed was based on the generation forecast for each of I&M's fossil generating units as projected by the AEPSC's Resource Planning Section and provided to me by Witness MacLean, and on the projection of fossil fuel deliveries and costs as developed by the AEPSC Fuels, Emissions and Logistics Department and provided to me by Witness

West.

The cost of fossil fuel consumed for each of I&M's generating units is equal to the number of tons of coal consumed multiplied by the average unit cost of coal in fuel inventory ($/ton), Account 151.

For the 2014 plan year, the cost of fuel consumed was developed on a monthly basis. The average cost of coal was defined as the weighting of the average cost of coal in inventory at the beginning of the month plus the projected cost of fuel delivered during the month. The tons of coal consumed were calculated by Witness MacLean using the *PLEXOS*® simulation model.

Exhibit IM-14 (RAR-1), line 2 includes fuel handling costs and ash disposal costs net of ash sales proceeds which are then credited (as shown on Exhibit IM-14 (RAR-1), lines 28 and 30) against the total power supply cost. Exhibit IM-14 (RAR-1), line 2 also includes affiliated transportation costs which are subject to base rate recovery. As such, these costs are also credited against the total power supply cost as shown on Exhibit IM-14 (RAR-1), line 29.

Q. On September 17, 2013, I&M announced that Tanners Creek Unit 4 (TC 4) will be retired by mid-2015 and will not be converted to burn natural gas. Is this decision reflected in the Company's PSCR forecast for 2014 through 2018?

A. No. For purposes of this PSCR forecast, TC 4 was assumed to be retrofitted in 2015 to burn natural gas.

Q. Is the retirement of TC 4 expected to impact on I&M's 2014 plan year PSCR forecast?

A. No. Since the retirement of TC 4 does not occur until mid-2015, I&M does not expect this to affect its costs in 2014 and, accordingly, its projection for this filing would remain unchanged.

Q. Would you please explain why the impact of the retirement of TC 4 is not reflected in this filing?

A. Yes. Given the timing of the decision and the filing deadline in this case, I&M was not able to model the impact of the retirement in its five year forecast. Nevertheless, I&M does not expect there to be a material difference in the PSCR if the retirement were reflected in its five year forecast.

Nuclear Fuel Expense

Q. Would you please describe how the projection of nuclear fuel expense was developed?

A. Yes. Nuclear fuel expense was forecasted for each unit of the Donald C. Cook Nuclear Plant. The projection of nuclear fuel expense consists of a base fuel component and post-April 7, 1983 spent nuclear fuel disposal costs. The base fuel component is calculated by multiplying the number of British thermal units (BTU's) generated by the nuclear fuel by the BTU charge. Lease finance and administrative charges are then added to this amount. Post-April 7, 1983 spent nuclear fuel disposal costs are calculated based on the rate of one mill per kilowatt-hour of electricity generated and sold in accordance with the Nuclear Waste Policy Act of 1982. The projections of nuclear generation and nuclear fuel expense were provided to me by Witness Bellville.

Allowance Consumption and Allowance Gains/(Losses)

Q. Does I&M's 2014 PSCR Plan forecast include any emission allowance expenses or credits arising from compliance with environmental regulations?

A. Yes. I&M's 2014 PSCR Plan includes emission allowance expenses related to the Clean Air Interstate Rule (CAIR).

Q. Does the Cross State Air Pollution Rule (CSAPR) have an impact on the 2014 PSCR Plan forecast?

A. No. The CSAPR, which was to be the replacement for the CAIR, was vacated by the District of Columbia Circuit Court of Appeals in August 2012. The U.S. Supreme Court has agreed to hear the U.S. Environmental Protection Agency's (EPA) appeal of the vacatur. However, a ruling is not expected until sometime in 2014 and it is not likely that the CSAPR would be immediately reinstated. I&M's plan is consistent with the District Court's instruction for the EPA to continue to implement CAIR until a valid replacement rule is adopted.

Q. Does Title IV of the Clean Air Act have an impact on the 2014 PSCR Plan forecast?

A. Yes. Title IV, which regulates emissions of SO_2, is included in the CAIR, since CAIR SO_2 reductions are achieved through the retirement of Title IV SO_2 allowances.

Q. What is I&M's PSCR Plan forecast for emission allowance expenses and credits in 2014?

A. I&M is forecasted to incur $13,873,000 of SO_2 allowance expenses in 2014 as shown on Exhibit IM-14 (RAR-1), line 8. The CAIR also includes both Seasonal NO_x and Annual NO_x emission limits. I&M is expected to incur $59,000 of NO_x allowance expenses in 2014. Gains from allowance sales as shown on Exhibit IM-14 (RAR-1), line 27 are forecasted at zero as a result of the vacatur of the CSAPR.

<u>Consumables</u>

Q. For what purposes does I&M use consumables?

A. I&M currently consumes activated carbon at its Rockport Plant, where it is injected into the flue gas stream to reduce mercury emissions.

Dry sorbent injection equipment is forecasted to be placed in service on Rockport Unit 1 in December 2014 and on Rockport Unit 2 in April 2015. This equipment will use sodium bicarbonate in a process designed to reduce SO_2 emissions by 50%. Because of the timing of the in-service dates, only the sodium bicarbonate expense consumed at Unit 1 in December 2014 is included in the 2014 PSCR Plan forecast.

I&M also has the ability to consume urea at its Tanners Creek Plant, where it can be injected into the boilers of Units 1, 2, and 3 to reduce NO_x emissions from those units when economically beneficial compared to the cost of consuming NO_x allowances.

Q. What costs are included in I&M's 2014 PSCR Plan as a result of using these consumables?

A. I&M's 2014 PSCR forecast includes expenses associated with the consumption of activated carbon at Rockport Plant. The 2014 forecast also includes expenses associated with the consumption of sodium bicarbonate at Rockport Unit 1 in December 2014. Because of the timing of the in-service date for the equipment to be installed on Unit 2, sodium bicarbonate expense associated that unit is not included in the forecast for 2014. It is included in the PSCR forecast for 2015 through 2018.

I&M is not forecasted to incur expenses associated with the consumption of urea at the Tanners Creek Plant due to low forecasted NO_x allowance prices. Consumable expenses are shown on Exhibit IM-14 (RAR-1), line 9.

Purchased Power

Q. Referring to Exhibit IM-14 (RAR-1), what costs are reflected in lines 10-12 associated with Purchased Power?

A. Purchased Power includes the costs of planned and unplanned non-affiliated purchases, planned wind purchases, and planned purchases from the AEP Generating Company (AEG).

Q. Would you please describe the non-affiliated purchases?

A. Yes. Non-affiliated purchases include planned purchases from the Ohio Valley Electric Corporation (OVEC) as well as I&M's share of the unplanned purchases I&M occasionally will make from non-affiliated suppliers to meet its total load.

Q. How were the costs associated with the non-affiliated purchases determined?

A. The projected gigawatt-hours (GWh) purchased from OVEC reflect I&M's share of the anticipated OVEC surplus. The cost associated with these purchases is based on a contractual agreement with OVEC.

For 2014, the costs associated with other non-affiliated system purchases were based on I&M's stand-alone projected unplanned energy purchases that I&M occasionally would be expected to make from non-affiliated suppliers.

Q. Do the projected 2014 PSCR costs include Wind Purchases?

A. Yes. The total cost of I&M's wind power purchases are included in the 2014 forecast of PSCR costs, as shown on Exhibit IM-14 (RAR-1), line 11. The total cost includes purchases from the Fowler Ridge and Wildcat I Wind Farms. Purchases from Fowler Ridge are included pursuant to the MPSC Order in Case U-15361, dated December 4, 2007 and the MPSC Order in Case U-15808, dated September 15, 2009. Wildcat I purchases are included pursuant to the MPSC Order in Case U-16584, dated August 25, 2011.

Q. Would you please describe the purchases from AEG?

A. Planned purchases from AEG represent the purchase of 70% of the power and energy from AEG's share of Rockport Units 1 & 2. The costs associated with these purchases are composed of both fuel and non-fuel charges.

Q. Would you please explain the derivation of the non-fuel charges associated with the Rockport Unit's 1 and 2 unit power purchases from AEG?

A. Yes. Pursuant to the Unit Power Agreement between I&M and AEG (FERC Rate Schedule No. 1), as amended, I&M agrees to pay AEG, in consideration for the right to receive a portion of the output from AEG's share of Rockport Units 1 & 2, an amount sufficient to enable AEG to pay its operating and other expenses, as well as to provide a return on its investment. The projection of the non-fuel charges for the 2014 plan year was calculated based upon the terms of the Unit Power Agreement, approved by the FERC on August 1, 1984, and reflects I&M's purchase of 70% of the power to which AEG is entitled from Rockport Unit's 1 and 2 (which is equivalent to 35% of the total power from both units).

Off-System Sales Received From Pool / Energy Delivered to Pool for Off-System Sales

Q. Referring to Exhibit IM-14 (RAR-1), lines 13 and 22, why are there no costs associated with Off-System Sales Received from Pool included in the 2014 PSCR forecast or credits associated with Energy Delivered to Pool for Off-System Sales?

A. In the past, these costs and credits were allocated to I&M as a member of the AEP Power Pool. These costs and credits will disappear with the dissolution of the AEP Power Pool on January 1, 2014.

Primary Energy Received / Delivered

Q. Referring to Exhibit IM-14 (RAR-1), lines 14 and 23, why are there no Primary Energy Received costs or credits for Primary Energy Delivered in the 2014

PSCR forecast?

A. In the past, I&M received primary energy from the AEP System Pool and delivered it as well. When the AEP Power Pool is dissolved on January 1, 2014, primary energy will no longer be supplied to or delivered by I&M.

PJM Interconnection LLC (PJM) Ancillaries

Q. Would you please identify the items included in PJM Ancillaries that result from the AEP East System's participation in the PJM Regional Transmission Organization?

A. Yes. PJM Ancillaries include operating reserve charges and credits as well as charges and credits for ancillary services. In the past, these charges and credits were allocated to I&M based its forecasted member load ratio. In the 2014 PSCR Plan forecast, these charges and credits will be direct assigned.

Q. Can you provide a brief description of these services provided by PJM?

A. Yes, the following provides a brief description:

PJM Operating Reserves – Operating reserve charges cover the operating reserve credits provided as make-whole payments to generators that are called on by PJM out of economic dispatch order and do not receive sufficient revenues from the energy or ancillary service markets to cover their offers.

Ancillary Services – These charges and credits are associated with services that are necessary to support the transmission of capacity and energy from resources to loads, while maintaining reliable operation of the transmission system.

Capacity Settlement Charges and/or Credits

Q. Referring to Exhibit IM-14 (RAR-1), lines 16 and 24, why are there no Capacity Settlement Charges or Credits included in the 2014 PSCR forecast?

A. These charges and credits disappear with the dissolution of the AEP Power Pool on January 1, 2014.

Financial Transmission Rights (FTR) Revenue, Net of Congestion Costs - Load Serving Entity (LSE)

Q. Would you please describe the FTR Revenue, Net of Congestion Costs – LSE that are included in Exhibit IM-14 (RAR-1), line 17?

A. Yes. Congestion costs in PJM are simply the difference between what a load pays for energy and what a generator supplying the load receives for the energy it produces. If there were no congestion on any transmission line in PJM, the Locational Marginal Price (LMP) would be the same for all generators and loads across the entire PJM market region (not taking marginal losses into account). However, when transmission lines become constrained, LMPs vary across the entire region and the price for energy paid by the load is different than the price received for energy produced by the generator.

To offset this impact, LSEs and integrated utilities such as AEP are assigned auction revenue rights (ARRs) which can be converted into FTRs through PJM's FTR auctions. ARRs are an entitlement to receive an allocation of net FTR auction revenues and provide for a fixed stream of revenues based on the results of the FTR auctions. FTRs are financial instruments that entitle the holder to the right to receive compensation from PJM for congestion on the FTR’s path. All FTRs have a source point (beginning) and a sink point (end). The difference between the day-ahead FTR sink and source congestion components of LMP determine the value of each FTR path. Since the value of FTRs are based upon the congestion components of LMP, their value will rise and fall with congestion prices and therefore provide for a variable revenue stream that should track increases and decreases in congestion costs. The purpose of ARRs and FTRs is to help these load-serving customers mitigate the incremental costs associated with congestion by effectively offering the LSE a financial hedge to offset the uncertainty associated with such congestion impacts on LMPs.

Transmission Losses

Q. Would you please describe the Transmission Losses that are included in Exhibit IM-14 (RAR-1), line 18?

A. Yes. These costs and credits are associated with the financial settlement of transmission line losses due to resistance on the transmission system within PJM.

OSS Revenue Cost of Goods Sold (COGS)

Q. Referring to Exhibit IM-14 (RAR-1), line 25, would you please describe the credits associated with OSS Revenue COGS?

A. Yes. OSS Revenue COGS is the cost recovery portion of OSS revenue. Specifically, revenues related to known or committed system sales were developed in accordance with the terms of the specific existing agreements governing those known system sales. Since uncommitted system sales as described by Witness MacLean are primarily short-term in nature and are representative of spot market energy sales in PJM, the prices and the ultimate counter-party buyers from PJM are not known or knowable. As a result, the forecast of revenues from such uncommitted system sales was based on the recovery of the AEP production costs of making those wholesale energy sales along with a forecast of net realizations (revenues less out-of-pocket costs) based on expected (PJM) market conditions at the AEP-Dayton market hub.

The revenue shown on Exhibit IM-14 (RAR-1), line 25 recovers the variable cost of making the off-system sales. It includes the variable generating costs of fuel, fuel handling, one-half of maintenance costs, and emission allowance costs or the purchases associated with making these sales. Such costs are forecasted for I&M, within PJM, on a stand-alone basis.

OSS Margin (80%)

Q. Referring to Exhibit IM-14 (RAR-1), line 26, would you please describe the credits associated with OSS Margin (80%)?

A. Yes. OSS Margin (80%) represents the customers' portion of I&M's margins received from OSS. The OSS Margins are derived from physical operations (which are calculated by subtracting the variable cost of making OSS as described above from the related revenue) and financial transactions. This sharing of 80% of OSS margins was the level agreed to in the settlement of

Case No. U-16801, which was approved by the MPSC.

Adjustment for Fuel Handling and Affiliated Transportation Exclusion

Q. Have you excluded fuel handling and affiliated transportation costs in the determination of the Total Company – Michigan Basis power supply cost?

A. Yes. Consistent with Act 304, I have excluded $11,838,000 in fuel handling costs and $28,072,000 in affiliated transportation costs.

Adjustment for Ash Disposal Costs/Credits

Q. Have you excluded ash disposal costs/credits in the determination of the Total Company – Michigan Basis power supply cost?

A. Yes. Consistent with the Commission's Order in I&M's 2011 PSCR Plan, Case U-16433, which rejected the Company's proposal to include ash disposal costs and revenues in I&M's PSCR Clause as currently defined, I have excluded $2,288,000 in net ash disposal costs/credits.

Total Company- Michigan Basis Projected 2014
Power Supply Costs and Net Energy Requirements

Q. What are I&M's projected 2014 power supply costs and net energy requirements?

A. The 2014 power supply costs for I&M, on a total Company basis, are estimated to be $454,231,000 or 18.80 mills per kWh before consideration for any line losses, based on a net energy requirement of 24,153.5 GWh.

Q. Does this conclude your testimony?

A. Yes.

INDIANA MICHIGAN POWER COMPANY
2014-2018 MICHIGAN PSCR PLAN
TOTAL COMPANY - MICHIGAN BASIS
($000)

Line No.	Description	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014 Total
1	**Fuel Costs**													
2	Fossil Generation	$ 28,954	$ 28,391	$ 23,240	$ 17,133	$ 12,781	$ 23,761	$ 27,044	$ 25,095	$ 24,228	$ 22,395	$ 10,021	$ 20,018	$ 263,059
3	Nuclear Generation	$ 13,700	$ 12,395	$ 13,662	$ 13,230	$ 13,602	$ 13,125	$ 13,517	$ 13,508	$ 11,548	$ 8,495	$ 13,455	$ 13,723	$ 153,960
4														
5	Total Fuel Cost	$ 42,654	$ 40,786	$ 36,901	$ 30,362	$ 26,382	$ 36,886	$ 40,562	$ 38,603	$ 35,776	$ 30,890	$ 23,476	$ 33,741	$ 417,019
6														
7	Plus:													
8	Allowance Consumption	$ 1,571	$ 1,545	$ 1,244	$ 910	$ 742	$ 1,263	$ 1,424	$ 1,330	$ 1,318	$ 1,208	$ 512	$ 866	$ 13,933
9	Consumables	$ 643	$ 625	$ 621	$ 442	$ 279	$ 507	$ 566	$ 525	$ 539	$ 530	$ 196	$ 1,525	$ 6,999
10	Purchased Power Non-Affil	$ 5,091	$ 4,467	$ 4,542	$ 4,999	$ 4,945	$ 4,415	$ 4,932	$ 5,428	$ 5,152	$ 5,084	$ 4,967	$ 6,542	$ 60,563
11	Purchased Power - Wind	$ 4,606	$ 4,597	$ 4,388	$ 5,282	$ 3,283	$ 2,542	$ 1,938	$ 1,754	$ 2,835	$ 4,278	$ 4,564	$ 4,758	$ 44,826
12	Purchased Power - AEG	$ 24,502	$ 23,969	$ 24,012	$ 19,994	$ 16,210	$ 21,714	$ 22,955	$ 22,031	$ 22,506	$ 22,110	$ 14,440	$ 20,422	$ 254,864
13	Off-System Sales Received from Pool	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Primary Energy Received	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	PJM Ancillaries	$ 2,153	$ 1,893	$ 1,867	$ 2,257	$ 2,342	$ 2,224	$ 3,328	$ 2,556	$ 2,368	$ 2,205	$ 2,076	$ 1,817	$ 27,086
16	Capacity Settlement Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17	FTR Revenue Net of Congestion Costs - LSE	$ (520)	$ (1,073)	$ (261)	$ 2,627	$ (1,009)	$ 527	$ 620	$ (674)	$ (466)	$ 33	$ (1,143)	$ (1,424)	$ (2,763)
18	Transmission Losses	$ 1,931	$ 1,932	$ 1,882	$ 1,284	$ 1,028	$ 1,431	$ 1,685	$ 1,568	$ 1,492	$ 1,527	$ 1,631	$ 1,517	$ 18,909
19														
20														
21	Less:													
22	Energy Delivered to Pool for Off-System Sales	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
23	Primary Energy Delivered	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
24	Capacity Settlement Credits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
25	Off-System Sales Revenue COGS	$ 33,188	$ 33,201	$ 31,724	$ 23,959	$ 15,768	$ 24,435	$ 23,526	$ 22,270	$ 23,802	$ 17,121	$ 10,432	$ 21,979	$ 281,407
26	Off-System Sales Margin (80%)	$ 8,097	$ 6,933	$ 7,196	$ 5,200	$ 1,745	$ 5,612	$ 8,121	$ 7,078	$ 4,727	$ 2,082	$ 862	$ 5,947	$ 63,599
27	Allowance Gains/(Losses)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
28	Fuel Handling	$ 1,346	$ 1,326	$ 915	$ 687	$ 574	$ 1,106	$ 1,280	$ 1,188	$ 1,089	$ 956	$ 486	$ 885	$ 11,838
29	Affiliated Transportation	$ 2,704	$ 2,418	$ 1,543	$ 1,251	$ 1,315	$ 2,486	$ 3,474	$ 3,250	$ 2,688	$ 3,768	$ 1,272	$ 1,903	$ 28,072
30	Ash Disposal Cost/Credits	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 191	$ 2,288
31														
32	Total Power Supply Cost	$ 37,105	$ 34,674	$ 33,627	$ 36,870	$ 34,611	$ 37,680	$ 41,418	$ 39,144	$ 39,022	$ 43,748	$ 37,475	$ 38,859	$ 454,231
33														
34	Net Energy Requirement (GWh)	2,184.0	1,961.8	1,975.3	1,831.3	1,870.0	2,022.8	2,261.4	2,213.6	1,927.5	1,885.4	1,879.7	2,140.8	24,153.5
35														
36	PSCR Fuel Factor (mills/kWh) w/o Losses	16.98	17.67	17.02	20.13	18.50	18.62	18.31	17.68	20.24	23.20	19.93	18.15	18.80

INDIANA MICHIGAN POWER COMPANY
2014-2018 MICHIGAN PSCR PLAN
Net Energy Requirement
GWH

Line No.	Description	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	2014 Total
1	**Generation**													
2	Fossil	1,089.6	1,068.7	885.3	640.6	461.4	859.1	966.8	904.8	878.4	825.1	343.0	715.7	9,638.5
3	Nuclear	1,548.6	1,398.7	1,548.6	1,498.7	1,517.5	1,446.6	1,455.3	1,462.4	1,276.0	968.3	1,498.7	1,548.6	17,168.0
4	Hydro	10.3	9.6	11.7	12.2	10.6	8.5	7.7	6.9	5.1	7.3	8.6	10.6	109.1
5	Total Generation	2,648.5	2,477.0	2,445.6	2,151.5	1,989.5	2,314.2	2,429.8	2,374.1	2,159.5	1,800.7	1,850.3	2,274.9	26,915.6
6														
7	plus:													
8														
9	Purchased Power													
10	AEG	594.0	577.3	572.8	408.2	255.4	468.7	522.6	484.8	497.7	489.6	182.6	414.3	5,468.1
11	OVEC	91.0	69.2	71.6	73.4	70.1	62.9	73.0	70.1	59.9	71.3	58.6	64.2	835.4
12	Other System Purchases	-	0.2	0.4	13.1	15.4	5.5	14.6	27.1	18.6	22.3	28.3	84.9	230.5
13	Wind Purchases	72.6	71.0	73.7	86.1	56.0	43.0	31.5	30.2	47.4	70.7	77.7	74.0	733.9
14	Primary Energy Received from the Pool	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Total Purchased Power	757.7	717.7	718.5	580.9	397.0	580.1	641.7	612.2	623.6	653.8	347.3	637.4	7,267.8
16														
17	less:													
18														
19	Primary Energy Delivered	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Energy for System Sales	1,222.2	1,232.8	1,188.8	901.1	516.6	871.5	810.1	772.7	855.6	569.2	317.9	771.5	10,030.0
21														
22	Net Energy Requirement	2,184.0	1,961.8	1,975.3	1,831.3	1,870.0	2,022.8	2,261.4	2,213.6	1,927.5	1,885.4	1,879.7	2,140.8	24,153.5

INDIANA MICHIGAN POWER COMPANY
2014-2018 MICHIGAN PSCR PLAN
TOTAL COMPANY - MICHIGAN BASIS
($000)

Line No.	Description	2014 Total	2015 Total	2016 Total	2017 Total	2018 Total
1	**Fuel Costs**					
2	Fossil Generation	$ 263,059	$ 219,142	$ 244,984	$ 260,639	$ 261,345
3	Nuclear Generation	$ 153,960	$ 156,687	$ 150,144	$ 169,538	$ 171,151
4						
5	Total Fuel Cost	$ 417,019	$ 375,830	$ 395,128	$ 430,177	$ 432,496
6						
7	Plus:					
8	Allowance Consumption	$ 13,933	$ 4,557	$ 3,744	$ 3,217	$ 2,781
9	Consumables	$ 6,999	$ 33,226	$ 48,287	$ 59,917	$ 62,375
10	Purchased Power Non-Affil	$ 60,563	$ 67,208	$ 78,557	$ 71,996	$ 79,035
11	Purchased Power - Wind	$ 44,826	$ 72,702	$ 74,224	$ 75,057	$ 76,304
12	Purchased Power - AEG	$ 254,864	$ 275,175	$ 322,521	$ 335,000	$ 344,777
13	Off-System Sales Received from Pool	$ -	$ -	$ -	$ -	$ -
14	Primary Energy Received	$ -	$ -	$ -	$ -	$ -
15	PJM Ancillaries	$ 27,086	$ 28,877	$ 30,756	$ 31,371	$ 31,998
16	Capacity Settlement Charges	$ -	$ -	$ -	$ -	$ -
17	FTR Revenue Net of Congestion Costs - LSE	$ (2,763)	$ (4,220)	$ (4,304)	$ (4,390)	$ (4,478)
18	Transmission Losses	$ 18,909	$ 19,287	$ 19,673	$ 20,067	$ 20,468
19						
20						
21	Less:					
22	Energy Delivered to Pool for Off-System Sales	$ -	$ -	$ -	$ -	$ -
23	Primary Energy Delivered	$ -	$ -	$ -	$ -	$ -
24	Capacity Settlement Credits	$ -	$ -	$ -	$ -	$ -
25	Off-System Sales Revenue COGS	$ 281,407	$ 247,006	$ 291,206	$ 342,447	$ 345,510
26	Off-System Sales Margin (80%)	$ 63,599	$ 96,516	$ 141,671	$ 172,764	$ 180,364
27	Allowance Gains/(Losses)	$ -	$ -	$ -	$ -	$ -
28	Fuel Handling	$ 11,838	$ 7,762	$ 7,312	$ 7,291	$ 7,342
29	Affiliated Transportation	$ 28,072	$ 22,054	$ 27,825	$ 19,984	$ 23,839
30	Ash Disposal Cost/Credits	$ 2,288	$ 3,792	$ 3,822	$ 5,285	$ 6,362
31						
32	Total Power Supply Cost	$ 454,231	$ 495,512	$ 496,751	$ 474,641	$ 482,340
33						
34	Net Energy Requirement (GWh)	24,153.5	24,067.0	23,924.0	23,819.8	23,712.2
35						
36	PSCR Fuel Factor (mills/kWh) w/o Losses	18.80	20.58	20.76	19.92	20.34

INDIANA MICHIGAN POWER COMPANY
2014-2018 MICHIGAN PSCR PLAN
Net Energy Requirement
GWH

Line No.	Description	2014 Total	2015 Total	2016 Total	2017 Total	2018 Total
1	**Generation**					
2	Fossil	9,638.5	7,765.6	8,584.2	8,687.1	8,527.7
3	Nuclear	17,168.0	17,123.9	16,136.6	17,585.5	17,505.7
4	Hydro	109.1	111.7	110.6	110.5	110.5
5	Total Generation	26,915.6	25,001.2	24,831.4	26,383.1	26,143.9
6						
7	plus:					
8						
9	Purchased Power					
10	AEG	5,468.1	4,903.8	5,862.8	5,788.5	5,701.5
11	OVEC	835.4	1,001.6	1,190.4	1,267.4	1,280.3
12	Other System Purchases	230.5	305.8	357.4	60.5	102.5
13	Wind Purchases	733.9	1,385.2	1,390.7	1,385.2	1,385.2
14	Primary Energy Received from the Pool	-	-	-	-	-
15	Total Purchased Power	7,267.8	7,596.4	8,801.3	8,501.6	8,469.5
16						
17	less:					
18						
19	Primary Energy Delivered	-	-	-	-	-
20	Energy for System Sales	10,030.0	8,530.6	9,708.7	11,064.8	10,901.2
21						
22	Net Energy Requirement	24,153.5	24,067.0	23,924.0	23,819.8	23,712.2

DIRECT TESTIMONY OF CAROLE A. MYSER
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY
2014 PSCR PLAN CASE

Q. Would you please state your name and business address?

A. My name is Carole A. Myser. My business address is 700 Morrison Road, Gahanna, Ohio 43230-6642.

Q. By whom are you employed, and what is your position?

A. I am employed by American Electric Power (AEP) Service Corporation (AEPSC) as Manager–Transmission Settlements. AEPSC supplies engineering, financing, accounting, and similar planning and advisory services to the subsidiaries of the American Electric Power System including Indiana Michigan Power Company (I&M or Company).

Q. Would you please describe your educational and professional background?

A. I graduated from Wittenberg University in 1984 with a Bachelor of Arts degree in Business Administration with an Accounting emphasis. I was employed by the Firm now known as Deloitte & Touche as a Tax Consultant from 1984-87. In 1987, I joined AEPSC in the Tax Department and held various positions progressing to a Senior Tax Analyst. In 1998 I was promoted to a Transmission Marketing Analyst in Transmission Operations. Since 2003 I have progressed through several management levels in various departments: Manager-Transmission Marketing in Transmission Strategy & Business Development (2003), Manager Investor Relations (2005), Manager-Financial Reporting (2006), Manager – Transmission Settlements in Transmission

Operations (2008), and Manager – Transmission Settlements in Transmission Settlements & Investments (2012). I am a Certified Public Accountant in Ohio.

Q. What are your responsibilities as Manager – Transmission Settlements?

A. I am primarily responsible for the forecasting of transmission revenue and expenses, RTO transmission settlements reconciliations, and other third party transmission settlement activities.

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes. I have submitted testimony on behalf of I&M before the Michigan Public Service Commission (MPSC) in the 2013 PSCR Plan case and 2012 PSCR Reconciliation case.

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

A. The purpose of my testimony is to present the forecasts of the Company's monthly Open Access Transmission Tariff (OATT) expenses for the period January 2014 through December 2014 and annual OATT expenses for the years 2014 through 2018. I will also describe the methodologies employed to derive I&M's estimated OATT expenses.

Q. What exhibits are you sponsoring in this proceeding?

A. I am sponsoring the following exhibit:

- Exhibit IM-18 (CAM-1) identifies, by component, the forecasted monthly OATT expenses for the period January 2014 through December 2014, as well as the annual forecasted OATT expenses for 2015 - 2018.

Q. Would you please describe the OATT charges and credits included in the 2014 PSCR plan and proposed PSCR factors?

A. Based on the Commission's Order in Case No. U-16801, the charges and credits which constitute I&M's OATT expenses to be reflected in the PSCR factor are:

1. Network Integration Transmission Service (NITS);
2. Firm and Non-Firm Point-to-Point (PTP) Transmission Credits;
3. Schedule 1A Ancillary Service Charges;
4. PJM Transmission Enhancement Charges;
5. PJM Administration Fees;
6. RTO Start-up Cost Recovery Charges (SCRC);
7. PJM Expansion Cost Recovery Charges (ECRC).

Q. Please provide a general description of the OATT charges and credits and the methodologies utilized in the development of I&M's forecasted OATT expenses for the period of 2014 – 2018.

A. A discussion of the specific methodologies and assumptions used in the derivation of each of these items by category follows.

<u>Network Integrated Transmission Service</u>

Q. What are Network Integrated Transmission Service charges?

A. These are wholesale transmission expenses allocated to I&M for the company's usage of the AEP transmission system in PJM. PJM allocates a portion of the total costs required to provide reliable network transmission service to each load serving entity (LSE) in the AEP transmission zone. As an LSE, AEP is allocated a portion of the NITS costs, which it further allocates to its operating companies.

The AEP East Companies' charges are computed by applying the zonal NITS rate to the total AEP LSE Network Service Peak Load (NSPL) of the prior calendar year, coincident with the prior calendar year NSPL of the entire AEP zone. The NITS rates are calculated using the formula rates specified in Attachments H-14 and H-20 of the PJM OATT. The NITS rates are updated annually effective July 1. Pursuant to Appendix 1 of the Transmission Agreement, approved by the FERC on October 29, 2010 (FERC Docket No. ER09-1279-000), the NITS charges incurred by the AEP East Companies to serve load in the AEP Zone of PJM are further allocated to I&M based on its contribution to the AEP LSE average 12 month coincident peak (12CP) transmission load through October 31 of the prior year.

Q. How was the projection of Network Integrated Transmission Service expense developed?

A. I&M's projected NITS expense was developed using two methods. First, because the NITS rate billing determinants have already been approved by the FERC (Docket Nos. ER08-1329-000 and ER10-355-000) for the period of January – June 2014, these billing determinants are used to forecast total monthly NITS charges for this time period. The total AEP East NITS charge is determined by multiplying the NITS rate by the prior calendar year NSPL of the

AEP East LSEs in PJM. Once the total AEP NITS charge is forecasted, I&M's share of the charge is calculated based on its pro rata share of the AEP East Operating Companies' 12CP load.

To forecast the NITS expenses beyond the effective period of the FERC approved billing determinants, transmission revenue requirement projections were forecasted into the future. Load forecasts received from AEP's Economic Forecasting group are used to estimate future peak loads. These forecasted transmission revenue requirements are applied to project monthly NITS charges for the AEP East Operating Companies in PJM. The projected NITS charges are then allocated to I&M based on its projected 12CP load share.

<u>Firm and Non-Firm Point-to-Point Transmission Credits</u>

Q. What are Firm and Non-Firm Point-to-Point transmission credits?

A. Each month, PJM allocates revenues for both Firm and Non-Firm PTP transmission service to the various PJM Transmission Zones, proportionate to the revenue requirements for NITS in each zone. PJM further allocates the AEP Zone share of PJM PTP revenues directly to AEP and other NITS customers in the AEP Zone. I&M is then allocated a portion of AEP's PTP credits based on its 12 CP load share.

Q. How did you forecast Firm and Non-Firm PTP transmission credits?

A. PTP transmission credits are forecasted using the latest available actual credits appearing on the PJM Settlement statement based on recent transmission service reservations. For 2014, an average of I&M's actual annual PTP transmission credit for the 12 month period ending August 2013 was used to derive a monthly total applied to January – December 2014. This number was held constant as a reasonable forecast because in outer years demand for PTP transmission reservations is less reasonably predictable over the long term.

<u>Schedule 1A Ancillary Service Charges</u>

Q. What are Schedule 1A ancillary service charges?

A. These are charges paid by AEP to PJM for transmission scheduling and dispatch services provided by AEP East Operating Companies. PJM OATT Schedule 1A includes a rate, specified in $/MWh, for Scheduling, System Control and Dispatch Service provided by PJM Transmission Owners in each PJM Zone. The rate for that service is updated annually with the NITS formula rate updates discussed above.

Q. How was the projection of Schedule 1A ancillary service charges developed?

A. For the period of January – June 2014, the rate used in billing for Schedule 1A charges has been approved by the FERC. This rate is held constant throughout the forecast period. To forecast I&M's Schedule 1A charge in 2014, the current FERC approved Schedule 1A rate is multiplied by the total AEP LSE energy (MWh) forecasted for calendar year 2014 to derive the total AEP Schedule 1A charge. I&M's share of the total AEP Schedule 1A charge is calculated by applying the current FERC approved Schedule 1A rate to I&M's historical share of the forecasted load.

PJM Transmission Enhancement Charges

Q. What are PJM Transmission Enhancement charges?

A. The Transmission Enhancement expenses are paid by AEP to PJM to help fund investment in extra-high voltage transmission projects that are determined to be needed to maintain reliability throughout the entire PJM footprint (regional projects). The costs resulting from Regional Projects are allocated to the PJM Zones that are deemed to benefit from each project on an annual load-ratio share basis. The cost responsibility allocated to each zone for all RTEP projects is charged to NITS customers based on their respective NSPL shares. AEP then allocates a portion of its assigned transmission enhancement costs to I&M based on its 12CP load share.

Q. How was the projection of PJM Transmission Enhancement charges developed?

A. The latest transmission project information published by PJM is used to estimate transmission revenue requirements for regional projects with costs approved to be allocated to the AEP Zone. The latest FERC approved PJM regional cost allocation policy is used to estimate the portion of each project that can be expected to be allocated to the AEP Zone for the period 2014-2018. Of the total forecasted AEP Transmission Enhancement charge, I&M is allocated a percentage based on its forecasted share of the average 12 CP.

PJM Administrative Charges

Q. What are PJM Administrative charges?

A. PJM charges each market participant on a monthly basis a number of fees to recover its operating and administration costs. PJM also charges fees to transmission customers and other market participants to fund the operation of FERC and certain other organizations that are involved in management of transmission reliability and regulation. These fees are defined in PJM OATT Schedules 9 and 10, and are approved by the FERC. Administrative costs incurred by the PJM RTO are passed on to member LSE's through an energy based rate ($/MWh).

Q. How was the projection of PJM Administrative charges developed?

A. We used the available projected administrative fee rate information for 2014 and 2015 released by PJM to project charges for the entire forecast period. Historical actual charges were adjusted proportionally to the projected rates for 2014 and 2015. An annual estimated growth rate of 2% is applied for the period 2016 – 2018. I&M's share of the total PJM administrative charge is determined by I&M's Member Load Ratio (MLR).

<u>RTO Start-Up Cost Recovery Charges</u>

Q. What are RTO Start-Up Cost Recovery Charges?

A. The RTO Start-Up Cost Recovery Charges (SCRC) recover the AEP East Companies' direct costs for RTO development and start-up. The charge is only billed to customers in the AEP Zone in PJM. The SCRC rate collects the costs associated with the AEP East Operating Companies joining PJM and FERC-approved carrying costs over a fifteen-year amortization period scheduled to end in 2020.

Q. How was the projection of RTO Start-up Cost Recovery Charges developed?

A. Collectively, the AEP Zone in PJM is annually charged $2,362,185, plus any applicable true-up adjustment, for RTO SCRC. Because the RTO SCRC charge is an amortized expense, we do not forecast a significant change in I&M's expenses for this charge. Therefore, we used a historical 12 month average to project these expenses for the forecast period.

<u>PJM Expansion Cost Recovery Charges</u>

Q. What are PJM Expansion Cost Recovery charges?

A. PJM expansion cost recovery charges (ECRC) recover costs that PJM originally incurred to expand the RTO's capability to accommodate the addition of new zones added during 2004 and 2005 (including the AEP zone). Although PJM incurred these costs, the AEP East Companies, Commonwealth Edison Company (ComEd), the Dayton Power and Light Company (Dayton), and Dominion Virginia Power (Dominion) are required to reimburse PJM. AEP, ComEd and Dayton filed a proposal at the FERC for PJM to recover the expansion costs over a ten-year period from all customers of the RTO. The outcome of that case was a settlement pursuant to which customers in all PJM zones except the Dominion Zone pay ECRC rates. Dominion elected not to include its expansion costs in the ECRC charges and was exempted from paying the ECRC charges that implement region-wide recovery of the AEP, ComEd and Dayton costs. The ECRC rates will be collected for ten years, through April 2015, coinciding with the FERC-approved amortization period for the PJM expansion costs

Q. How was projection of PJM Expansion Cost Recovery charges developed?

A. Pursuant to PJM OATT Schedule 13, the ECRC rates are designed to collect approximately 1/10 of the total amount of $52,549,556 each twelve months of the Cost Recovery Period. The portion of that amount being collected in the New PJM Zone (which includes the AEP zone) is $30,864,989. The charges are applied to the NSPL of the Network Customers in each applicable zone. Because the ECRC charge is an amortized expense, a significant change in I&M's charge is not expected. Therefore, a historical 12 month average was used to project these expenses for the forecast period.

Q. How were these projected OATT costs included in I&M's projected PSCR costs?

A. The projected OATT costs are incorporated in the development of the proposed PSCR factor as described by witness Hille.

Q. Does this conclude your prefiled direct testimony?

A. Yes.

Indiana Michigan Power Company
Total Company Projected OATT Expenses

Basis for Cost Allocation ($000)

Line No.	Description	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Total 2014
	Total I&M													
1	PJM Administrative Charges	1,039	930	875	766	821	930	985	985	821	875	875	1,039	10,941
	Retail Energy Only													
2	Schedule 1A Ancillary Service Charges	150	140	151	159	155	152	155	155	164	166	152	159	1,859
	Retail Demand Only													
3	Network Integration Transmission Service (NITS) Charges	8,626	7,791	8,626	8,348	8,626	8,348	10,350	10,343	10,009	10,343	10,009	10,343	111,761
4	Firm and Non-Firm Point to Point Transmission Credits	(145)	(136)	(108)	(109)	(117)	(138)	(149)	(156)	(165)	(177)	(143)	(174)	(1,716)
5	PJM Transmission Enhancement Charges	1,053	1,053	1,053	1,053	1,053	1,094	1,229	1,229	1,229	1,229	1,229	1,229	13,732
6	RTO Start-up Cost Recovery Charges	42	38	42	41	42	41	42	42	41	42	41	42	496
7	PJM Expansion Cost Recovery Charges	46	46	46	46	46	46	46	46	46	46	46	46	552

Indiana Michigan Power Company
Total Company Projected OATT Expenses

Basis for Cost Allocation ($000)

Line No.	Description	Annual 2014	Annual 2015	Annual 2016	Annual 2017	Annual 2018
	Total I&M					
1	PJM Administrative Charges	10,941	12,509	13,503	13,707	13,922
	Retail Energy Only					
2	Schedule 1A Ancillary Service Charges	1,859	1,186	950	948	943
	Retail Demand Only					
3	Network Integration Transmission Service (NITS) Charges	111,761	128,392	141,326	156,872	172,623
4	Firm and Non-Firm Point to Point Transmission Credits	(1,716)	(1,716)	(1,716)	(1,716)	(1,716)
5	PJM Transmission Enhancement Charges	13,732	19,467	25,488	28,833	28,561
6	RTO Start-up Cost Recovery Charges	496	497	498	497	497
7	PJM Expansion Cost Recovery Charges	552	276			

DIRECT TESTIMONY OF DAVID L. HILLE
ON BEHALF OF
INDIANA MICHIGAN POWER COMPANY
2014 PSCR PLAN CASE

Q. Please state your name and business address.

A. My name is David L. Hille. My business address is One Summit Square, P. O. Box 60, Fort Wayne, Indiana 46801.

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

A. I am employed by Indiana Michigan Power Company (I&M or Company) as Principal Regulatory Consultant in the Regulatory Services Department.

Q. Please briefly describe your educational and business experience.

A. I graduated from Ball State University in 1983 with a Bachelor of Science Degree in Accounting. After graduating in 1983, I joined American Electric Power Service Corporation as an Auditor Assistant performing operational reviews of the area offices of I&M and Michigan Power Company. As an internal auditor, I became experienced in the process of inspecting and analyzing data and then drawing conclusions and reporting findings based on the data inspected.

In May 1986, I accepted a position in I&M's Rates and Tariffs Department as a Rate Analyst. My duties included preparing data used in formal and informal rate proceedings that included monthly, quarterly, and annual filings.

In September 1991, I was named to Senior Rate Analyst. My duties in that position involved the accumulation, documentation, presentation, and review of data for various rate proceedings. In January 1996, I became

Manager of Rates and Regulations responsible for matters concerning various rate proceedings and fuel factors and the supervision of the preparation of various reports or studies, as required. In particular, I am responsible for preparing or reviewing I&M's monthly Power Supply Cost Recovery (PSCR) reports and coordinating the preparation and filing of I&M's annual PSCR plan and reconciliation cases. The department and my position were later changed to Regulatory Services and Senior Regulatory Consultant, respectively, and I have since been named Principal Regulatory Consultant but my central responsibilities remained the same. I directly report to the Director of Regulatory Services

Q. Have you previously submitted testimony in any regulatory proceedings?

A. Yes. I testified before the Michigan Public Service Commission (MPSC) in I&M's 1996, 1997, and 2004 PSCR Plan Cases and I&M's 1996 and 1997 PSCR Reconciliation Cases. I also submitted testimony to the MPSC in I&M's 1995, 1998, 1999, 2000, and 2005 through 2013 PSCR Plan Cases and I&M's 1994, 1995, 1998, and 2004 through 2012 PSCR Reconciliation Cases. In addition, I have testified before the Indiana Utility Regulatory Commission in I&M's fuel cost proceedings.

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

A. The purpose of my testimony in this proceeding is to support the calculation of I&M's PSCR Plan Case factors for each of the billing months of January through December 2014, describe the estimated roll in over/under-recoveries from the 2013 PSCR Plan case, and support the resultant revised tariff sheet.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, Exhibit IM-19 (DLH-1), page 1 of 2, shows the calculation of the proposed PSCR factor applicable to the billing months of January through December 2014. Page 2 of 2 shows the estimated under-recovery expected at the end of the 2013 PSCR plan year. Exhibit IM-20 (DLH-2) calculates the applicable transmission factor includable within the PSCR clause. Exhibit IM-21 (DLH-3) contains the revised tariff sheet that reflects the proposed PSCR factor.

Q. How did you calculate the proposed PSCR factor?

A. The PSCR factor was calculated in accordance with the methodology approved in I&M's most recent general base rate proceeding, Case No. U-16801. As shown on Exhibit IM-19 (DLH-1), page 1 of 2, I calculated the proposed PSCR factor using data provided by Witness Riley by dividing the sum of the monthly forecasted costs by the sum of the monthly net energy requirements, adjusting the resulting quotient for losses by applying a 4.6% loss factor, adding the PSCR transmission factor, and then subtracting the 23.77 mills per kWh power supply cost base approved in Case No. U-16801. In addition, the effect of the roll-in methodology, shown on line 8, results in a proposed PSCR factor of 2.55 mills per kWh applicable to the billing months of January through December 2014.

Q. Why did you use a 4.6% loss factor?

A. In accordance with the Order Approving Settlement Agreement in MPSC Case

No. U-16801, the 4.6% loss factor established in that proceeding shall be used for PSCR purposes until a new loss factor is established in a subsequent base rate case.

Q. Does the proposed PSCR factor include costs related to transmission?

A. Yes. Consistent with the Order Approving Settlement Agreement in MPSC Case No. U-16801, I&M's most recent base rate case, the PSCR factor includes those transmission items established in that case.

Q. How were amounts related to those transmission items forecasted?

A. A description of the transmission items and the forecasted amounts are supported by Witness Myser.

Q. How was the factor associated with these transmission items determined?

A. As set forth in the methodology in Case No. U-16801, the projected amounts, by category, are divided by the projected net energy requirement as supplied by Witness Riley, then multiplied by the respective allocation adjustment and loss factor at levels established in the base rate case. The transmission factors are shown on Exhibit IM-20 (DLH-2).

Q. Do the projected transmission factors include the transmission phase-in credits based on the schedule set forth in Case No. U-16801?

A. Yes, those credits are shown on Exhibit IM-20 (DLH-2), line 29, and in accordance with that schedule, the credits expire in June 2014.

Q. What is the result of these calculations?

A. As shown on Exhibit IM-20 (DLH-2) the 2014 projected transmission factor is

7.30 mills/kWh.

Q. Where is the proposed PSCR factor reflected in I&M's tariffs?

A. I&M's proposed PSCR factor is included on Sheet No. D-110.00, as shown in Exhibit IM-21 (DLH-3). When the Commission issues an order approving the 2014 PSCR Plan factor, the approved factor will be reflected on Sheet No. D-110.00.

Q. Can you briefly describe the benefits of the roll-in methodology?

A. The roll-in method spreads the over/under-recovery amount across all twelve months of the plan year, minimizing its impact on customers while providing rate stability. In addition, the roll-in methodology is administratively more efficient and cost effective for I&M than the historical refund/surcharge method. Furthermore, when a refund or surcharge appears on customer's bills during specified months this increases customer inquires and volatility in customer bills. In summary, I&M believes the roll-in methodology provides customers with better rate stability, improves bill clarity, minimizes customer confusion and uncertainty, and is more administratively and cost efficient.

Q. Are you aware if the roll-in methodology has been implemented by other companies?

A. It is my understanding that this methodology is being utilized in numerous PSCR and Gas Cost Recovery (GCR) filings of various companies.

Q. Please describe Exhibit IM-19 (DLH-1), page 2 of 2?

A. Exhibit IM-19 (DLH-1), page 2 of 2, sets forth by month, I&M's current 2013 plan year actual and estimated over/under-recoveries. Actual over/under recovered amounts are shown for January through July 2013 and, preliminary over/under-recoveries are shown for August along with estimates for the balance of the year. The calculation of interest, for both actual and estimated over/under-recovery balances, has been performed in the same manner as past I&M reconciliation cases. The estimated annual over-recovery amount, including interest, is $1,788,861. Consistent with the roll-in methodology approved by the MPSC in Case No. U-15004, this under-recovered amount has been rolled into the 2014 Plan Year's proposed power supply cost recovery factor calculation as shown on Exhibit IM-19 (DLH-1), page 1 of 2.

Q. How are over or under-recoveries determined in the annual PSCR reconciliation?

A. There are no changes in the way over or under-recoveries are determined in the annual PSCR reconciliation.

Q. Does I&M plan to accrue interest on over/under-recoveries?

A. Yes, over and under-recoveries will accrue interest on a monthly basis during the 12 month PSCR period at the rates prescribed in Act 304.

Q. What is the net effect on customers' bills as a result of the proposed PSCR Plan Case factors?

A. I&M's customers will experience a decrease of 3.11 mills per kWh as a result of the proposed factor of 2.55 mills per kWh.

Q. Are I&M's policies and the costs included in this plan reasonable and prudent and in accordance with the provisions of Act 304?

A. Yes. I&M's objective is to achieve the lowest total unit cost of electricity to customers over the long term while insuring an adequate and reliable supply of energy. The testimony of Witness West addresses I&M's sources and cost of coal and the testimony of Witness Bellville illustrates how I&M's fuel procurement practices minimize the cost of nuclear fuel, while the testimony of Witnesses MacLean and Riley support the overall sources of power supply of I&M’s expected demand and net energy requirements to meet its objective. Furthermore, Witness Myser supports the manner in which AEP’s OATT meets this objective.

Q. Does this complete your direct testimony?

A. Yes.

Indiana Michigan Power Company
Determination of the Michigan Jurisdiction
Power Supply Cost Recovery Factor
January 2014 - December 2014

Line No.	Description	Twelve Month Totals	
1	Total Power Supply Costs (000's)	$454,231	
2	Net Energy Requirement (GWh)	24,154	
3	Line 1 / Line 2	18.80	Mills/kWh
4	Line 3 * 1.046	19.66	Mills/kWh
5	Plus: PSCR Transmission Factor (See Exhibit DLH-2)	7.30	Mills/kWh
6	Less Current Power Supply Cost Base	23.77	Mills/kWh
7	Subtotal - Line 4 plus Line 5 less Line 6	3.19	Mills/kWh
8	Estimated 2013 Over-recovery of $1,788,861 / 2,797,000,000 Est'd kWh 2014	(0.64)	Mills/kWh
9	PSCR Billing Factor for the Michigan Jurisdiction - Line 7 + Line 8	2.55	Mills/kWh

Indiana Michigan Power Company
Current 2013 PSCR Plan Year Over/(Under) Recoveries
Michigan Jurisdiction

	Description	Actual Jan	Actual Feb	Actual Mar	Actual Apr	Actual May	Actual Jun	Actual Jul	Preliminary Aug	Estimated Sep	Estimated Oct	Estimated Nov	Estimated Dec	Total
1	Sales subject to PSCR (KWh)	245,297,312	239,389,982	236,403,079	233,230,863	209,508,952	223,490,021	253,408,220	248,287,843	240,900,000	210,300,000	211,000,000	244,500,000	2,795,716,272
2	PSCR Base Incl Losses (Mills/kWh)	23.77	23.77	23.77	23.77	23.77	23.77	23.77	23.77	23.77	23.77	23.77	23.77	
3	PSCR Factor (Mills/kWh)	5.66	5.66	5.66	5.66	5.66	5.66	5.66	5.66	5.66	5.66	5.66	5.66	
4	Total PSCR Revenues Lines [1*(2 + 3)]	7,219,100	7,045,247	6,957,342	6,863,983	6,165,849	6,577,312	7,457,804	7,307,111	7,089,687	6,189,129	6,209,730	7,195,635	$82,277,929
5	Applicable Power Costs	5,472,583	6,528,165	6,640,562	7,624,317	6,302,029	5,980,593	7,199,328	5,991,186	6,407,940	6,670,716	6,057,810	6,535,485	$77,410,714
6	Over/(Under) Recovery Lines [4 - 5]	$1,746,517	$517,082	$316,780	($760,334)	($136,180)	$596,719	$258,476	$1,315,925	$681,747	($481,587)	$151,920	$660,150	$4,867,215
7	Beginning Recovery Balance (1)	($3,153,543)	($1,407,026)	($889,944)	($573,164)	($1,333,498)	($1,469,678)	($835,845)	($577,369)	$738,556	$1,420,303	$938,716	$1,090,636	
8	Ending Recovery Balance Lines [6 + 7] (2)	($1,407,026)	($889,944)	($573,164)	($1,333,498)	($1,469,678)	($835,845)	($577,369)	$738,556	$1,420,303	$938,716	$1,090,636	$1,750,786	
9	Average Recovery Balance Lines [7 + 8] / 2	($2,280,285)	($1,148,485)	($731,554)	($953,331)	($1,401,588)	($1,152,762)	($706,607)	$80,594	$1,079,430	$1,179,510	$1,014,676	$1,420,711	
10	Applicable Interest Rate	0.40%	0.36%	0.36%	0.36%	0.34%	0.33%	0.32%	10.20%	10.20%	10.20%	10.20%	10.20%	
11	Monthly Interest Lines [9 * 10] / 12	($760)	($345)	($219)	($286)	($397)	($317)	($188)	$685	$9,175	$10,026	$8,625	$12,076	$38,075
12	YTD Interest	($760)	($1,105)	($1,324)	($1,610)	($2,007)	($2,324)	($2,512)	($1,827)	$7,348	$17,374	$25,999	$38,075	
13	Rolling Over/(Under) Recovery Lines [8 + 12]	($1,407,786)	($891,049)	($574,488)	($1,335,108)	($1,471,685)	($838,169)	($579,881)	$736,729	$1,427,651	$956,090	$1,116,635	$1,788,861	
									Total Overrecovery and Interest					$1,788,861

(1) January beginning balance represents the amount as filed in the 2012 PSCR reconciliation case U-16891-R.
(2) June under recovery balance reduced by the credit as ordered in Case No. U-17223 of $37,114

Indiana Michigan Power Company
Total Company Projected OATT Expenses

Line No.	Basis for Cost Allocation ($000) Description	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14
1	**Total I&M**						
2	PJM Administrative Charges	1,039	930	875	766	821	930
3	PJM Administrative Charge - Default assessments	0	0	0	0	0	0
4	**Subtotal I&M**	**1,039**	**930**	**875**	**766**	**821**	**930**
5	Net Energy Requirement (GWh)	2,184	1,962	1,975	1,831	1,870	2,023
6	Transmission Cost (mills/kWh) w/o Losses (L4/L5)	0.48	0.47	0.44	0.42	0.44	0.46
7	Allocation Adjustment (L46)	1.0023	1.0023	1.0023	1.0023	1.0023	1.0023
8	Transmission Factor (mills/kWh) w/o Losses (L6xL7)	0.48	0.48	0.44	0.42	0.44	0.46
9	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046	1.046
10	**TOTAL I&M Transmission Factor (mills/kWh) w/ Losses (L8xL9)**	**0.50**	**0.50**	**0.46**	**0.44**	**0.46**	**0.48**
11							
12	**Retail Energy Only**						
13	Schedule 1A Ancillary Service Charges	150	140	151	159	155	152
14	(Transmission Owner Scheduling, System Control and Load Dispatching)						
15	**Subtotal Retail Energy Only**	**150**	**140**	**151**	**159**	**155**	**152**
16	Net Energy Requirement (GWh)	2,184	1,962	1,975	1,831	1,870	2,023
17	Transmission Cost (mills/kWh) w/o Losses (L15/L16)	0.07	0.07	0.08	0.09	0.08	0.08
18	Allocation Adjustment (L46)	1.2932	1.2932	1.2932	1.2932	1.2932	1.2932
19	Transmission Factor (mills/kWh) w/o Losses (L17xL18)	0.09	0.09	0.10	0.11	0.11	0.10
20	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046	1.046
21	**Retail Energy Transmission Factor (mills/kWh) w/ Losses (L19xL20)**	**0.09**	**0.10**	**0.10**	**0.12**	**0.11**	**0.10**
22							
23	**Retail Demand Only**						
24	Network Integration Transmission Service (NITS) Charges	8,626	7,791	8,626	8,348	8,626	8,348
25	Firm and Non-Firm Point to Point Transmission Credits	(145)	(136)	(108)	(109)	(117)	(138)
26	PJM Transmission Enhancement Charges	1,053	1,053	1,053	1,053	1,053	1,094
27	RTO Start-up Cost Recovery Charges	42	38	42	41	42	41
28	PJM Expansion Cost Recovery Charges	46	46	46	46	46	46
29	Revised Transmission Agreement Phase-In Credits	(500)	(500)	(500)	(500)	(500)	(500)
30	**Subtotal Retail Demand Only**	**9,122**	**8,292**	**9,159**	**8,879**	**9,150**	**8,891**
31	Net Energy Requirement (GWh)	2,184	1,962	1,975	1,831	1,870	2,023
32	Transmission Cost (mills/kWh) w/o Losses (L30/L31)	4.18	4.23	4.64	4.85	4.89	4.39
33	Allocation Adjustment (L46)	1.274	1.274	1.274	1.274	1.274	1.274
34	Transmission Factor (mills/kWh) w/o Losses (L32xL33)	5.32	5.38	5.91	6.18	6.23	5.60
35	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046	1.046
36	**Retail Demand Transmission Factor (mills/kWh) w/ Losses (L34xL35)**	**5.57**	**5.63**	**6.18**	**6.46**	**6.52**	**5.86**
37							
38	**Transmission Factor (mills/kWh) w/ Losses (L10+L21+L36))**	**6.16**	**6.23**	**6.75**	**7.02**	**7.09**	**6.44**
39							

Line No.		Total I&M	Retail Energy	Retail Demand
40	*Derivation of Allocation Adjustment*	*Total I&M*	*Retail Energy*	*Retail Demand*
41				
42	Applicable Allocation Factor	14.28826%	18.43603%	18.16327%
43				
44	MI Energy Allocation Factor	14.25592%	14.25592%	14.25592%
45				
46	Allocation Adjustment (L42/L44)	1.0022685	1.2932192	1.27408613

Exhibit IM-20 (DLH-2)
Case No. U-17318

Indiana Michigan Power Company
Total Company Projected OATT Expenses

Line No.	Basis for Cost Allocation ($000) Description	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Total 2014
1	**Total I&M**							
2	PJM Administrative Charges	985	985	821	875	875	1,039	10,941
3	PJM Administrative Charge - Default assessments	0	0	0	0	0	0	0
4	**Subtotal I&M**	**985**	**985**	**821**	**875**	**875**	**1,039**	**10,941**
5	Net Energy Requirement (GWh)	2,261	2,214	1,928	1,885	1,880	2,141	24,154
6	Transmission Cost (mills/kWh) w/o Losses (L4/L5)	0.44	0.44	0.43	0.46	0.47	0.49	0.45
7	Allocation Adjustment (L46)	1.0023	1.0023	1.0023	1.0023	1.0023	1.0023	1.0023
8	Transmission Factor (mills/kWh) w/o Losses (L6xL7)	0.44	0.45	0.43	0.47	0.47	0.49	0.45
9	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046	1.046	1.046
10	**TOTAL I&M Transmission Factor (mills/kWh) w/ Losses (L8xL9)**	**0.46**	**0.47**	**0.45**	**0.49**	**0.49**	**0.51**	**0.47**
11								
12	**Retail Energy Only**							
13	Schedule 1A Ancillary Service Charges	155	155	164	166	152	159	1,859
14	(Transmission Owner Scheduling, System Control and Load Dispatching)							
15	**Subtotal Retail Energy Only**	**155**	**155**	**164**	**166**	**152**	**159**	**1,859**
16	Net Energy Requirement (GWh)	2,261	2,214	1,928	1,885	1,880	2,141	24,154
17	Transmission Cost (mills/kWh) w/o Losses (L15/L16)	0.07	0.07	0.09	0.09	0.08	0.07	0.08
18	Allocation Adjustment (L46)	1.2932	1.2932	1.2932	1.2932	1.2932	1.2932	1.2932
19	Transmission Factor (mills/kWh) w/o Losses (L17xL18)	0.09	0.09	0.11	0.11	0.10	0.10	0.10
20	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046	1.046	1.046
21	**Retail Energy Transmission Factor (mills/kWh) w/ Losses (L19xL20)**	**0.09**	**0.09**	**0.12**	**0.12**	**0.11**	**0.10**	**0.10**
22								
23	**Retail Demand Only**							
24	Network Integration Transmission Service (NITS) Charges	10,350	10,343	10,009	10,343	10,009	10,343	111,761
25	Firm and Non-Firm Point to Point Transmission Credits	(149)	(156)	(165)	(177)	(143)	(174)	(1,716)
26	PJM Transmission Enhancement Charges	1,229	1,229	1,229	1,229	1,229	1,229	13,732
27	RTO Start-up Cost Recovery Charges	42	42	41	42	41	42	496
28	PJM Expansion Cost Recovery Charges	46	46	46	46	46	46	552
29	Revised Transmission Agreement Phase-In Credits	0	0	0	0	0	0	(3,000)
30	**Subtotal Retail Demand Only**	**11,518**	**11,504**	**11,160**	**11,483**	**11,182**	**11,486**	**121,825**
31	Net Energy Requirement (GWh)	2,261	2,214	1,928	1,885	1,880	2,141	24,154
32	Transmission Cost (mills/kWh) w/o Losses (L30/L31)	5.09	5.20	5.79	6.09	5.95	5.36	5.04
33	Allocation Adjustment (L46)	1.274	1.274	1.274	1.274	1.274	1.274	1.274
34	Transmission Factor (mills/kWh) w/o Losses (L32xL33)	6.49	6.62	7.37	7.76	7.58	6.84	6.43
35	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046	1.046	1.046
36	**Retail Demand Transmission Factor (mills/kWh) w/ Losses (L34xL35)**	**6.79**	**6.92**	**7.71**	**8.12**	**7.93**	**7.15**	**6.72**
37								
38	**Transmission Factor (mills/kWh) w/ Losses (L10+L21+L36))**	**7.34**	**7.49**	**8.28**	**8.72**	**8.52**	**7.76**	**7.30**
39								

Line No.	Description	Total I&M	Retail Energy	Retail Demand
40	*Derivation of Allocation Adjustment*	*Total I&M*	*Retail Energy*	*Retail Demand*
41				
42	Applicable Allocation Factor	14.28826%	18.43603%	18.16327%
43				
44	MI Energy Allocation Factor	14.25592%	14.25592%	14.25592%
45				
46	Allocation Adjustment (L42/L44)	1.0022685	1.2932192	1.2740861

Indiana Michigan Power Company
Total Company Projected OATT Expenses

Line No.	Basis for Cost Allocation ($000) Description	Annual 2014	Annual 2015	Annual 2016	Annual 2017	Annual 2018
1	**Total I&M**					
2	PJM Administrative Charges	10,941	12,509	13,503	13,707	13,922
3	PJM Administrative Charge - Default assessments	0	0	0	0	0
4	**Subtotal I&M**	**10,941**	**12,509**	**13,503**	**13,707**	**13,922**
5	Net Energy Requirement (GWh)	24,154	24,067	23,924	23,820	23,712
6	Transmission Cost (mills/kWh) w/o Losses (L4/L5)	0.45	0.52	0.56	0.58	0.59
7	Allocation Adjustment (L46)	1.0023	1.0023	1.0023	1.0023	1.0023
8	Transmission Factor (mills/kWh) w/o Losses (L6xL7)	0.45	0.52	0.57	0.58	0.59
9	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046
10	**TOTAL I&M Transmission Factor (mills/kWh) w/ Losses (L8xL9)**	**0.47**	**0.54**	**0.59**	**0.60**	**0.62**
11						
12	**Retail Energy Only**					
13	Schedule 1A Ancillary Service Charges	1,859	1,186	950	948	943
14	(Transmission Owner Scheduling, System Control and Load Dispatching)					
15	**Subtotal Retail Energy Only**	**1,859**	**1,186**	**950**	**948**	**943**
16	Net Energy Requirement (GWh)	24,154	24,067	23,924	23,820	23,712
17	Transmission Cost (mills/kWh) w/o Losses (L15/L16)	0.08	0.05	0.04	0.04	0.04
18	Allocation Adjustment (L46)	1.2932	1.2932	1.2932	1.2932	1.2932
19	Transmission Factor (mills/kWh) w/o Losses (L17xL18)	0.10	0.06	0.05	0.05	0.05
20	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046
21	**Retail Energy Transmission Factor (mills/kWh) w/ Losses (L19xL20)**	**0.10**	**0.07**	**0.05**	**0.05**	**0.05**
22						
23	**Retail Demand Only**					
24	Network Integration Transmission Service (NITS) Charges	111,761	128,392	141,326	156,872	172,623
25	Firm and Non-Firm Point to Point Transmission Credits	(1,716)	(1,716)	(1,716)	(1,716)	(1,716)
26	PJM Transmission Enhancement Charges	13,732	19,467	25,488	28,833	28,561
27	RTO Start-up Cost Recovery Charges	496	497	498	497	497
28	PJM Expansion Cost Recovery Charges	552	276	0	0	0
29	Revised Transmission Agreement Phase-In Credits	(3,000)	0	0	0	0
30	**Subtotal Retail Demand Only**	**121,825**	**146,916**	**165,596**	**184,486**	**199,965**
31	Net Energy Requirement (GWh)	24,154	24,067	23,924	23,820	23,712
32	Transmission Cost (mills/kWh) w/o Losses (L30/L31)	5.04	6.10	6.92	7.75	8.43
33	Allocation Adjustment (L46)	1.274	1.274	1.274	1.274	1.274
34	Transmission Factor (mills/kWh) w/o Losses (L32xL33)	6.43	7.78	8.82	9.87	10.74
35	Loss Correction Multiplier	1.046	1.046	1.046	1.046	1.046
36	**Retail Demand Transmission Factor (mills/kWh) w/ Losses (L34xL35)**	**6.72**	**8.14**	**9.22**	**10.32**	**11.24**
37						
38	**Transmission Factor (mills/kWh) w/ Losses (L10+L21+L36))**	**7.30**	**8.75**	**9.87**	**10.98**	**11.91**
39						
40	*Derivation of Allocation Adjustment*	*Total I&M*		*Retail Energy*		*Retail Demand*
41						
42	Applicable Allocation Factor	14.28826%		18.43603%		18.16327%
43						
44	MI Energy Allocation Factor	14.25592%		14.25592%		14.25592%
45						
46	Allocation Adjustment (L42/L44)	1.0022685		1.2932192		1.2740861

Exhibit IM-21 (DLH-3)
Case No. U-17318

INDIANA MICHIGAN POWER COMPANY

REVISED TARIFF SHEET TO REFLECT PROPOSED PSCR FACTOR

POWER SUPPLY COST RECOVERY FACTOR

(Continued from Sheet No. D-109.00)

Not more than 45 days following the last day of each billing month in which a power supply cost recovery factor has been applied to customers' bills, the Company shall file with the Commission a detailed statement for that month of the revenues recorded pursuant to the power supply cost recovery factor, the allowance for cost of power included in the base rates established in the latest Commission order for the Company, and the cost of power supply.

Not less than once a year and not later than 90 days after the end of the 12-month period covered by the Company's most recently authorized power supply cost recovery plan, a power supply cost reconciliation proceeding will be commenced to reconcile the revenues recorded pursuant to the power supply cost recovery factor and the allowance for cost of power included in the base rates as established by the Commission under the Company's most recent power supply cost recovery plan, among other things. The Company shall be required to refund to customers, or to credit to customers' bills any net amount, plus interest, determined to have been recovered which is in excess of the amounts properly expensed by the Company for power supply. The Company shall recover from customers any net amount, plus interest, by which the amount determined to have been recovered over the period covered was less than the amount determined to have been properly expensed by the Company for power supply.

Maximum allowable Power Supply Cost Recovery Factors approved by the Commission:

(1)	(2)	(3)	(4)	
Billing Month	Total PSCR Costs (Mills/kWh)	PSCR Costs In Base Rates (Mills/kWh)	PSCR Factor Charge/(Credit) (Mills/kWh)	
			(Col. 2 - Col. 3)	
May – Dec. 2012	25.24	23.77	1.47	D
Jan. – Dec. 2013	29.45	23.77	5.68	

Should the Company apply a lesser factor than the above, or if the factor is later revised pursuant to Commission Orders or 1982 PA 304, the Company will notify the Commission if necessary and file a revision to the above list.

Actual Power Supply Cost Recovery factors billed pursuant to 1982 PA 304, Section 6j(9):

(1)	(2)	(3)	(4)	
Billing Month	Total PSCR Costs (Mills/kWh)	PSCR Costs In Base Rates (Mills/kWh)	PSCR Factor Charge/(Credit) (Mills/kWh)	
			(Col. 2 - Col. 3)	
May – Dec. 2012	25.24	23.77	1.47	D
Jan. – Dec. 2013	29.43	23.77	5.66	
Jan. – Dec. 2014	26.32	23.77	2.55	N