Exhibit H

Minnesota Public Utilities Commission Docket No. E-001/PA-01-1505
Responses to Information Requested in Order

Minnesota Public Utilities Commission Docket No. E-001/M-05-406
Responses to Information Requested in December 20, 2006 – Order Establishing Accounting Treatment for MISO Day 2 Costs

Minnesota Public Utilities Commission Docket No. E-001/M-05-406
Responses to Information Requested in February 6, 2008 – Order Acting on Electric Utilities, Annual Reports, Requiring Further Filings, and Amending Order of December 20, 2006 on Passing MISO Day 2 Costs through Fuel Clause

Minnesota Public Utilities Commission Docket No. E-001, 015, 002, 017/M-08-528
Responses to Information Requested in August 23, 2010 – Order Authorizing Ongoing Use of the Fuel Clause Adjustment and Setting Reporting Requirement in the Matter of IPL's Petition for Approval of Proposed Accounting to Recover Costs and Pass Through Revenues Related to MISO Ancillary Services.

Minnesota Public Utilities Commission Docket Nos. E-999/AA-09-961 & 10-884 Responses to Information Requested in April 6, 201 – Order Acting on Electric Utilities' Annual Reports and Requiring Additional Filings.

Minnesota Public Utilities Commission Docket No. E999/AA-11-792 Responses to Information Requested in August 16, 2013 – Order Acting on Electric Utilities' Annual Reports, Requiring Refund of Certain Curtailment Costs, and Requiring Additional Filings

(PUBLIC)

INTERSTATE POWER & LIGHT COMPANY
Minnesota Public Utilities Commission Order in Docket No. E-001/PA-01-1505
Responses to Information Requested in Order

3) Report, as part of its Annual Automatic Adjustment of Charges report (AAA) filed under Minnesota Rules part 7825.2800, the following:

a) The Schedule 10 administrative charges paid to the MISO under the MISO tariff.

IPL has been allocated $2,636,328.60 for Schedule 10 administrative charges that Alliant Energy has paid to MISO for the period July 1, 2014 – June 30, 2015. The Minnesota jurisdictional allocation of these charges is $152,907.06.

See Attachment H.

b) Any amount of MISO administrative charge deferred by the MISO for later recovery.

See below for a comparative balance sheet analysis December 2014 vs. December 2015 which contains deferred MISO charge information.

Midcontinent Independent System Operator, Inc.

Balance Sheet

(Dollars In Thousands)

	December 31 2014	December 31 2013
Assets		
Current assets:		
Cash and cash equivalents *(Note 5)*	$ 67,161	$ 89,391
Restricted cash *(Note 5)*	674,304	537,888
Cash - deposits *(Note 5)*	60,097	44,748
Accounts receivable *(Note 6)*	24,947	26,799
Deferred regulatory assets *(Note 4)*	7,967	5,683
Prepayments	10,198	8,676
Other	3,193	2,751
Total current assets	847,867	715,936
Fixed assets:		
Fixed assets *(Note 7)*	496,859	478,780
Accumulated depreciation and amortization	(369,270)	(328,538)
	127,589	150,242
Projects in development	41,061	21,583
Net fixed assets	168,650	171,825
Other assets:		
Deferred note offering fee	749	853
Deferred regulatory assets *(Note 4)*	18,362	23,401
Total assets	$ 1,035,628	$ 912,015
Liabilities		
Current liabilities:		
Accounts payable	$ 3,645	$ 3,587
Accrued liabilities *(Note 8)*	83,379	70,014
Accrued interest	2,782	3,116
Restricted deposits	535,772	420,359
Market participant liability	106,402	93,537
FERC assessment liability	19,325	14,258
Current portion of capitalized leases *(Note 12)*	1,023	938
Notes payable *(Note 14)*	–	18,485
Deferred revenue	6,143	8,594
Total current liabilities	758,471	632,888
Long-term liabilities:		
Accrued liabilities	11,237	9,989
Restricted deposits	16,526	12,451
Capitalized leases, net of current portion *(Note 12)*	6,957	7,980
Deferred revenue	42,437	48,707
Notes payable *(Note 14)*	200,000	200,000
Total long-term liabilities	277,157	279,127
Total liabilines	$ 1,035,628	$ 912,015

See accompanying notes.

Midcontinent Independent System Operator, Inc.

Notes to Financial Statements (continued)
(Dollars In Thousands)

4. Regulatory Assets and Liabilities

The following regulatory assets and liabilities were included in the deferred regulatory assets and liabilities lines on the balance sheets:

Transmission:	Current Schedule 10	Settlement Agreement	Data Center Loss Schedule 10	Grid America/ Ameren/ Illinois Power Payments	South Region Schedule 10	Total
December 31, 2012	$ 1,105	$ 417	$ 879	$ 4,402	$ 8,430	$ 15,233
Amortization	-	(417)	(879)	(3,453)	(1,771)	(6,520)
Current Year Deferral	(13)	-	-	-	12,523	12,510
December 31, 2013	1,092	-	-	949	19,182	21,223
Amortization	-	-	-	(949)	(3,837)	(4,786)
Current Year Deferral	(424)	-	-	-	-	(424)
December 31, 2014	$ 668	$ -	$ -	$ -	$ 15,345	$ 16,013

Markets/Other:	Current Market Costs Sch. 16	Current Market Costs Sch. 17	Data Center Loss Sch. 16 & 17	Pension Plan	South Region Sch. 16 & 17	Total
December 31, 2012	$ 453	$ 1,602	$ 925	$ 1,438	$ 6,492	$ 10,910
Amortization	-	-	(925)	-	-	(925)
Current Year Deferral	(670)	(3,431)	-	(789)	2,766	(2,124)
December 31, 2013	(217)	(1,829)	-	649	9,258	7,861
Amortization	-	-	-	-	(1,851)	(1,851)
Current Year Deferral	185	3,472	-	649	-	4,306
December 31, 2014	$ (32)	$ 1,643	$ -	$ 1,298	$ 7,407	$ 10,316

Regulatory Assets Total:	Current	Non-Current	Total
Transmission	$ 4,504	$ 11,509	$ 16,013
Markets	3,463	5,555	9,018
Other	-	1,298	1,298
Total	$ 7,967	$ 18,362	$ 26,329

The "Current Schedule 10, 16 and 17" rates are based on forecasted billing units and expenditures. Differences between revenue collected and actual costs for the month are included in subsequent months' rate calculations. These costs are classified as deferred regulatory assets and will be recovered in a subsequent period.

4. Regulatory Assets and Liabilities (continued)

MISO entered into an FERC-approved settlement agreement over the definition of megawatt hours of transmission service in the Schedule 10 – ISO Cost Recovery Adder, which resulted in the deferral of $25,000 of costs incurred during 2003, to be recovered over a five-year period, which began February 1, 2008. All deferred costs associated with the settlement agreement have been recovered as of February 28, 2013.

In September 2011, during construction of MISO's Carmel Data Center, an air handling unit suffered a mechanical failure. The failure caused metallic dust contamination throughout the Data Center and related information technology (IT) equipment that had already been installed prior to beginning operations. As a result of this contamination, MISO removed the contaminated IT equipment and remediated the Data Center. MISO was able to salvage $629 of existing contaminated equipment and rebuilt the Data Center and replaced it with new uncontaminated IT equipment. MISO received FERC approval on April 4, 2012, to defer the loss of $11,140. On July 12, 2012, MISO received a final net insurance settlement check in the amount of $5,100. On August 23, 2012, MISO filed with the FERC regarding the amortization of the remaining $5,400 loss related to the Data Center. On January 4, 2013, the FERC approved MISO's request to amortize the $5,400 loss over a six-month period beginning September 1, 2012. The loss associated with the Data Center has been fully recovered as of February 28, 2013.

MISO paid $23,174 to the participants in Grid America to reimburse them for expenditures they made to develop Alliance Regional Transmission Organization and to comply with the requirements of FERC Order 2000. Pursuant to an FERC order, these costs were deemed to be costs of MISO to be recovered under the Tariff over a 10-year period. All deferred costs associated with the settlement agreement have been recovered as of September 30, 2013.

Ameren Services Company (Ameren) joined MISO and MISO paid $26,075 to Ameren, including $18,000 to reimburse the exit fee that Ameren paid in 2001 to withdraw from MISO, $949 in interest on the exit fee, and $7,126 to reimburse Ameren for expenditures it made to develop Alliance Regional Transmission Organization and to comply with the requirements of FERC Order 2000. The $7,126 and $949 were deferred costs to be recovered over a 10-year period. All deferred costs associated with the settlement agreement have been recovered as of April 30, 2014.

Midcontinent Independent System Operator, Inc.

Notes to Financial Statements (continued)
(Dollars In Thousands)

4. Regulatory Assets and Liabilities (continued)

Illinois Power Company joined MISO and MISO paid \$15,452, including \$6,382 to reimburse the exit fee that Illinois Power Company paid in 2001 to withdraw from MISO, \$373 in interest on the exit fee, and \$8,697 to reimburse Illinois Power Company for expenditures it made to develop Alliance Regional Transmission Organization and to comply with the requirements of FERC Order 2000. The \$8,697 and \$373 were deferred costs to be recovered over a 10-year period. All deferred costs associated with the settlement agreement have been recovered as of September 30, 2014.

The operating costs associated with integrating the South Region, including Entergy and additional entities located within the Entergy and MISO footprint, are being deferred in order to align the recovery of costs associated with the integration effort with those that benefit from the integration of the South Region. The deferred cost of the integration was \$28,440, consisting of internal and external operational staff, extended regulatory proceedings travel, and customer outreach. MISO will recover the deferred integration costs under appropriate Schedules 10, 16, and 17 over a five-year period beginning January 1, 2014.

On December 1, 2012, MISO assumed the role of the independent coordinator of transmission (ICT) for the Entergy system from Southwest Power Pool effective until Entergy fully integrated into MISO on December 19, 2013. As ICT for the Entergy region, MISO served as the reliability coordinator and tariff administrator, managed long-term transmission planning, and conducted Entergy's weekly power procurement process. MISO deferred costs of \$1,930 associated with providing ICT services, which were recovered over a 12-month period beginning December, 1 2012, the date in which MISO assumed the role of ICT for Entergy. All deferred costs associated with ICT services have been recovered as of December 31, 2013.

5) Do the following:

c) Report to the Commission, in IPL's annual AAA report, each instance where the MISO directed IPL to curtail IPL's owned generation, for reliability reasons, that resulted in an interruption of firm retail electric service to IPL's retail customers in Minnesota.

No such instances occurred for the period July 1, 2014 through June 30, 2015.

d) Report to the Commission in IPL's annual AAA report each instance where the MISO directed the curtailment of a delivery of a firm purchased power supply that subsequently resulted in an interruption of firm retail electric service to IPL's retail customers in Minnesota.

No such instances occurred for the period July 1, 2014 through June 30, 2015.

8) Do the following:

b) Report in its AAA report on changes to MISO tariffs that may ultimately affect the rates of retail customers in Minnesota, and on IPL's efforts to minimize MISO transmission service costs.

In the period between July 1, 2014 and June 30, 2015, the Federal Energy Regulatory Commission (FERC) has issued numerous orders accepting, or conditionally accepting proposed revisions to MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff). In general, any modification of the Tariff has the potential to ultimately affect the rates of retail customers in Minnesota.

Either Alliant Energy Corporate Services, Inc. (AECS), on behalf of its utility affiliates IPL and Wisconsin Power and Light Company (WPL), or IPL and WPL directly, intervene in many of the FERC dockets dealing with proposed revisions to MISO's Tariff, in order to represent the interest of the utilities' customers. Recent examples of IPL's involvement in FERC dockets that impact the Tariff are as follows:

EL12-35-000, ER13-2379-000: Following complaints regarding MISO transmission formula rates, FERC initiated an investigation in 2012, noting that the current structure may be unjust, unreasonable, unduly discriminatory, preferential or otherwise unlawful. IPL submitted comments to FERC in June 2012. In May 2013, FERC issued an order which found that MISO's and individual company formula rate protocols are insufficient. FERC directed MISO and the impacted TOs, which includes ITC-M, to make certain changes to their formula rate protocols. MISO and the TOs, including ITC-M, collaborated on their compliance filing and filed at FERC on September 13, 2013. On October 18, 2013, AECS on behalf of its affiliate utilities IPL and WPL, filed comments at FERC on the compliance filing. On March 20, 2014, FERC conditionally accepted the September 2013 compliance filing and denied a rehearing request on its 2013 order for changes in MISO's

Attachment O tariff protocols. FERC has recognized the comments made by AECS, OMS and others that new protocols filed by the MISO and the TOs focused on the processes and timelines to review and challenge the after-the-fact rates. The new protocols did not clearly provide any additional mechanisms for review and challenge of the projected rates for the following year, such as those IPL is subject to from ITC-M. FERC indicated in the March 2014 order that the May 2013 order was meant to apply to projected revenue requirements as well. On April 18, 2014, OMS requested a rehearing and clarification of the March 20 order, asserting that FERC failed to make clear that the proposed protocols apply to the initial establishment of a formula rate revenue requirement by a MISO TO, and that FERC erred when it allowed the revised formula rate protocols to become effective on January 1, 2014, rather than the refund effective date of May 23, 2012, established in the May 2013 order. MISO and the TOs filed a revised compliance filing on May 19, 2014. Also on May 19, FERC issued a tolling order on OMS' rehearing request. On June 9, 2014, a group of Arkansas and Mississippi cooperative and municipal utilities (Joint Customers) filed a Protest at FERC against the MISO and the TOs on procedural, timeline and calculation issues. On June 12, 2014, the OMS filed a Motion to File Comments Out of Time and Comments of OMS regarding procedural issues.

EL14-12-000: On November 12, 2013, a group of industrial customer organizations in MISO filed a complaint at FERC seeking reduction of the base ROE (12.38%) used by the MISO TOs (including ITC-M) transmission rates to 9.15%, instituting a capital structure in which the assumed equity component does not exceed 50%, and eliminating the ROE adders currently approved for the other ITC Holdings operating companies in Michigan (ITCTransmission and METC) for being a member of a RTO and for being an independent transmission owner (Docket No. EL14-12-000). AECS filed an intervention without comments in Docket No. EL14-12-000 on December 10, 2013 on behalf of IPL and WPL as interested parties. On October 16, 2014, FERC issued an order on the MISO TO ROE complaint (Docket No. EL14-12-000): Established hearing and settlement judge procedures on the ROE element of the complaint, and setting a refund date of November 12, 2013, the date of the complaint, Denied the request to limit the capital structure of MISO TOs to 50% equity, Denied the request to eliminate the ROE incentive adders of ITC Transmission and METC; ITC Holdings companies operating in Michigan, Dismissed the portion of the complaint that includes MISO as a party. Settlement discussions on the MISO TO ROE complaint were initiated on November 13, 2014. The parties last met on December 16, 2014 but were not able to continue progress toward an appropriate base ROE. The settlement judge declared an impasse and filed a report on December 17, 2014 recommending the matter be scheduled for evidentiary hearing. In FERC orders issued for the MISO base ROE complaint in January and February 2015, FERC appointed a Presiding Administrative Law Judge (ALJ) and established a pre-hearing conference and the hearing procedural schedule. The Commencement of Hearing is scheduled for August 17, 2015 with an Initial Decision to be issued by the ALJ by November 30, 2015. A final decision by the Commission is not expected until the middle of 2016.

EL15-45-000: On February 12, 2015, a group of cooperative and municipal utilities in MISO filed a second complaint at FERC seeking reduction of the base ROE (12.38%) used by the MISO TOs (including ITC-M) transmission rates to 8.67%. AECS filed an intervention without comments on February 20, 2015 on behalf of IPL and WPL as interested parties. On June 18, 2015, FERC issued an order, established hearing procedures, leaving the requested consolidation with EL14-12-000 to the discretion of the Chief Administrative Law Judge. A refund date of February 12, 2015 was set. On June 24, 2015, the Chief Administrative Law Judge denied consolidation with EL14-12-000. FERC indicated it expects the presiding judge should be able to render a decision within 12 months of the commencement of hearing procedures, or by June 30, 2016. Thus, absent any settlement, FERC estimates it would be able to issue a final decision by May 31, 2017.

ER15-358-000: On November 6, 2014, a group of MISO TOs, including ITC-M, filed a request at FERC to implement a 50 basis point RTO incentive adder to each TOs ROE for participation in MISO.

An effective date of November 7, 2014 was requested, however, collection of the RTO adder was requested to be deferred until after the issuance of a final order addressing the pending MISO base ROE complaint EL14-12-000. The TOs acknowledge that the requested adder would be added to the base ROE for each TO only to the extent that the addition of the adder results in a total ROE within the range of reasonable returns established by FERC. On November 26, 2014, AECS filed comments on the MISO TO request for a 50 basis point RTO incentive. AECS filed comments highlighting certain information related to transmission development in MISO to aid FERC's decision making process; specifically that the historical transmission investment in the MISO footprint has been robust and that MISO currently employs a number of risk mitigation measures that affect the investment environment of the MISO TOs and should be considered by the Commission, such as forward-looking rates. AECS also noted general support for prudent transmission investment that balances reliability needs with customer cost impacts. Numerous other parties filed protests and comments. On January 5, 2015, FERC issued an order accepting the MISO TO request to implement a 50 basis point RTO incentive adder to each TOs ROE for participation in MISO. The Regional Transmission Organization (RTO) incentive adder is to become effective January 6, 2015, subject to refund, and subject to the outcome of the MISO base ROE proceeding in EL14-12-000 which will establish the MISO base ROE and cap implementation of any ROE incentive adders to the upper end of the zone of reasonableness. Collection of the RTO incentive adder is also deferred pending the outcome of the MISO base ROE proceeding. Various rehearing requests were filed. On March 4, 2015, FERC issued a tolling order to allow further time for it to consider the rehearing requests.

ER15-945-000: On January 30, 2015, ITC-M filed for a 100 basis point incentive adder for its status as a Transco, or independent transmission company. An effective date of the same as the filing was requested, however, collection of the independence adder was requested to be deferred until after the issuance of a final order addressing the pending MISO base ROE complaint EL14-12-000. ITC-M acknowledges that the requested adder would be added to the base ROE only to the extent that the addition of the adder results in a total ROE within the range of reasonable returns established by FERC. On February 20, 2015, IPL filed comments, requesting FERC to reevaluate its overall transmission ROE incentive policies to ensure the policies are meeting the intended goals, including consideration of cost impacts to customers, before considering the ITC-M request. In the alternative, IPL requested consolidation of the request with the broader evaluation of the MISO TO ROE in EL14-12-000, as the most efficient, holistic, and expeditious means to resolve the ITC Midwest ROE matter. Numerous other parties filed protests and comments. On March 31, 2015, FERC granted ITC-M's request for an adder, but found 50 basis points to be reasonable given current market conditions. The independence adder is to become effective April 1, 2015, subject to refund, and subject to the outcome of the MISO base ROE proceeding in EL14-12-000 which will establish the MISO base ROE and cap implementation of any ROE incentive adders to the upper end of the zone of reasonableness. Collection of the independence adder is also deferred pending the outcome of the MISO base ROE proceeding. On April 29, 2015 MISO on behalf of ITC-M filed a compliance filing to reflect the ITC-M tariff changes for implementation of a 50 basis point independence ROE incentive adder upon determination of the MISO base ROE in Docket No. EL14-12-000. On April 30, 2015, ITC-M and RPGI filed rehearing requests. ITC-M argued for the full 100 basis points adder originally requested, while RPGI argued that granting of an independence adder is not justified. On June 1, 2015, FERC issued a tolling order to allow further time for it to consider the rehearing requests.

Additional detail about all of MISO's filings and FERC's orders related to MISO's filings can be found at the following hyperlink:

https://www.misoenergy.org/Library/FERCFilingsOrders/Pages/FERCFilings.aspx

In addition to AECS participation in FERC proceedings, AECS participates in the MISO stakeholder meetings to represent retail customers' interests and influence MISO's ultimate proposed tariff changes.

c) **Submit in its AAA reports an annual analysis of how the transfer of operational control to the MISO has affected IPL's overall transmission costs and revenues and its overall energy costs for retail customers, including –**

Overall energy costs for retail customers have not been significantly impacted by the formation of MISO, largely due to the elimination of rate pancaking. (see ii below). Under the MISO tariff, IPL has a Joint Rate Zone Agreement with Great River Energy (GRE) and Southern Minnesota Municipal Power Agency (SMMPA) where MISO charges for network transmission service. The Joint Rate Zone Agreement replaced service under previous agreements with GRE and SMMPA reducing expenses that IPL historically paid to GRE and SMMPA.

While costs have been attenuated by the MISO tariff and the Joint Rate Zone Agreement, some cost increase has been experienced since ITC Midwest acquired the transmission system from IPL in 2007. These costs reflect investments being made in the transmission system by ITC Midwest to improve reliability and reduce congestion. Multi-Value Projects (MVPs) are a newer category of large scale transmission projects in MISO; the first portfolio of which were approved by the MISO Board of Directors in late 2011. MVPs support reliability improvements, market efficiency and state mandates for renewable generation. MVP criteria require that they bring MISO-wide benefits and that the benefits out-weigh the costs, thus the costs of these projects are shared across the MISO footprint. These costs started being allocated in January 2012. The net impact of these changes to Minnesota retail ratepayers is small.

i. an analysis of how MISO membership has affected IPL's ability to use its own generating sources when they are the least cost power source and;

Through its generation offer and market clearing processes, the MISO market provides IPL the ability to effectively utilize its resources when they are the least cost power source, or other resources as economically appropriate. IPL typically commits its base load generating units and dispatches them to specified minimum output levels, while making additional output available to MISO based on the unit's offers. IPL typically leaves the commitment and dispatch decisions of its intermediate and peaking units to MISO based on offer parameters. In most cases where IPL commits and dispatches a unit at a specific level, the primary objective is to make certain that the unit remains on-line and is not cycled on and off.

ii. IPL's ability to access low cost power on the wholesale market for its retail customers.

IPL has designated all Minnesota jurisdictional load as network load under the MISO Tariff. Under the MISO Tariff, rate pancaking has been eliminated for transmission service within the MISO footprint. The elimination of pancaked rates reduces transmission costs, increasing the availability of economical energy resources to IPL. The MISO market also provides another source of energy for IPL's use to serve its retail load instead of owned generation and bilateral transactions. This additional source of energy adds to the diversity and availability of IPL's potential energy resources, which tends to lower energy costs.

INTERSTATE POWER & LIGHT COMPANY
Minnesota Public Utilities Commission Order in Docket No. E-001/M-05-406
Responses to Information Requested in Order

December 20, 2006 - Order Establishing Accounting Treatment for MISO Day 2 Costs

7) Each petitioning utility shall provide to the Department the following additional reporting requirements in their monthly FCA reports and AAA reports:

A) Each utility shall file as part of its electric AAA report certain information regarding its plans with respect to acquiring fuel and purchased power:

1) Each utility shall include in its AAA report an overview of its anticipated events and planned actions to address fuel clause costs, and the actions planned by the utility to minimize or lower such costs whenever possible. Each utility shall provide a discussion of tools for managing fuel clause costs including a) plans for use of financial instruments or other mechanisms to hedge the costs of natural gas or other fuels, b) plans to hedge purchased energy costs (either through forward bilateral purchases or financial instruments), including how the utility will plan for and cover fuel and energy risk during planned unit outages; and c) where deemed appropriate, plans for additional optimization of congestion cost hedging through the purchase and/or sale of FTRs in the MISO Day 2 Market.

1) a) and b):
In the past, IPL had requested variances from the fuel clause adjustment (FCA) rules, Minnesota Rules, parts 7825.2400-7825.2600, to recover the costs of financial hedging for its electric operations. IPL's hedging activities typically have included the use of financial and physical instruments to increase price stability. Financial hedging, however, has not been specifically approved for recovery under the FCA rules, hence the need to request a variance.

Due to concerns expressed at the Commission's November 22, 2011, Agenda Meeting, IPL re-examined its practice of requesting an additional variance from the FCA rules. IPL has followed the lead of its fellow Minnesota utilities by ceasing requests for variances from the FCA rules.

The last variance under Docket No. E001/M-11-494 expired June 30, 2013. As detailed in the letter expressing IPL's intent to discontinue future requests for a variance filed March 1, 2013 under this Docket, IPL avers that the last variance covers all financial hedges entered into prior to the variance expiration, regardless of whether the contracts were completed by that date. The remaining financial contracts transacted prior to the variance's expiration extended through December 2014. No financial hedges have been transacted for the Minnesota operations after the expiration of the variance. In conjunction with the FCA rules, IPL may continue to transact physically in order to address risks.

1) c):
IPL plans to continue to participate in MISO's FTR auction, utilizing FTRs to hedge against congestion exposure in the MISO market.

3) Each utility shall provide and update a list of the network resources that it designates used to serve native load.

See Attachment A.

B) To help customers manage their energy costs, each utility shall submit an annual FCA Forecast of the cost per MWh of fuel and purchased power costs for the next 12 months. This FCA Forecast shall include all fuel and energy costs associated with the operation of the utility's system, in addition to projected MISO Day 2 costs and revenues. The FCA Forecast shall identify major changes that impact the stability of the forecast resulting from underlying changes in the utility's cost inputs. The FCA Forecast shall address projected variances in fuel costs and purchased power due to increased volatility in fuel markets. Finally, each utility shall explain the reasons for deviations in the forecasts from actual costs in the previous year.

See Exhibit E.

Note: the 2016 forecast is based on the 2016 Strategic Plan fuel costs which incorporate adjustments for long-term growth rates from public information sources.

Major changes that impact the stability of the forecast resulting in the cost inputs as well as some of the reasons for deviations in forecasts from actual costs:

Timing and duration differences in planned major plant outages
Market prices of MISO energy market (buy and sell)
Forced plant outages
Market price of natural gas
Changes in the cost of coal commodity and transportation

C) Each utility shall prepare a summary of its AAA filing stating key factors affecting costs (including Revenue Sufficiency Guarantee costs and Revenue Neutrality Uplift costs) along with the FCA Forecast.

The major items identified in B above for major changes that impact the stability of the forecast resulting in the cost inputs are also the key factors affecting costs in the forecast.

INTERSTATE POWER & LIGHT COMPANY
Minnesota Public Utilities Commission Order in Docket No. E-001/M-05-406
Responses to Information Requested in Order

February 6, 2008 - Order Acting on Electric Utilities' Annual Reports, Requiring Further Filings, and Amending Order of December 20, 2006 on Passing MISO Day 2 Costs through Fuel Clause

18) All electric utilities subject to automatic adjustment filing requirements, with the exception of Dakota Electric, shall include in future annual automatic adjustment filings the actual expenses pertaining to maintenance of generation plants, with a comparison to the generation maintenance budget from the utility's most recent rate case.

See Attachment B.

21) All electric utilities subject to automatic adjustment filing requirements, with the exception of Dakota Electric, shall provide information requested by the Department in docket E,G-999/AA-07-1130 according to the spreadsheet attached to the 2007 Report pertaining to MISO Day 2 charges, one for every month in the AAA period, for a total of 13 pages in each utility's AAA filing.

See Attachment C.

INTERSTATE POWER & LIGHT COMPANY
Minnesota Public Utilities Commission Order in Docket No. E-001, 015, 002,017/M-08-528
Responses to Information Requested in Order

August 23, 2010 - Order Authorizing Ongoing Use of Fuel Clause Adjustment and Setting Reporting Requirements in the Matter of IPL's Petition for Approval of Proposed Accounting to Recover Costs and Pass Through Revenues Related to MISO Ancillary Services. The Commission also required specific reporting requirements in the annual automatic adjustment reports as well as continued reporting on the quarterly costs and benefits of the MISO ASM market.

5) **The three utilities shall include costs and revenues from their participation in the MISO ancillary services market in future automatic adjustment reports filed under Minn Rules, parts 7825.2390 *et seq.*, including the annual filing required thereunder. They shall include costs/revenues through June 30, 2010 in the 2011 annual filings, which are due September 2010; they shall include costs/revenues beginning July 1, 2010 in the 2012 annual filings, which are due in September 2011.**

   The required information for July 1, 2014 through June 30, 2015 is included in Attachment E of this annual automatic adjustment filing. The information is split into results for the third quarter 2014, fourth quarter 2014, first quarter 2015, and second quarter of 2015.

6) **The three utilities shall continue to monitor and report all negative benefits (costs) of participation in the MISO ancillary services market and shall work with MISO to ensure that negative benefits occur, if at all, for limited periods of time and with minimal financial impact.**

   IPL continues to actively monitor MISO and is engaged in MISO stakeholder activities. No negative benefits related to the MISO ASM have been detected to date. IPL will continue to work with MISO to identify, and ameliorate (if identified) any negative benefits of the ancillary services market.

7) **The three utilities shall base the formatting of their reports on costs and revenues associated with participation in the MISO ancillary services market on the format used by Xcel and Minnesota Power in this docket.**

   This requirement is addressed in the responses below.

8) **In their annual summaries on the 12 MISO ancillary service charges the utilities shall use a format similar to that used by Minnesota Power in its Attachment 1 to its February 5, 2010 filing (4th quarter report) and shall work with the Department to develop a format that is acceptable.**

   IPL has created its report of the 12 MISO ancillary services charges (and credits) using the same format that was used by Minnesota Power. Please see

Attachment D, which contains the information for the last two quarters of 2014 and the first two quarters of 2015.

9) **In reporting daily ancillary services market activity and overall net savings created by participation in the ancillary services market, utilities shall use a format similar to that used by Xcel in Attachment A to its February 5, 2010 filing and shall work with the Department to develop a format that is acceptable.**

IPL has reported to the Department that it is not able to replicate the Xcel format at the same level of granularity (i.e., daily costs and revenues). IPL is able to display accounting costs and revenues aggregated at the monthly level of detail, which is found in Attachment D, Pages 1 - 8. Attachment E combines the monthly accounting costs and revenues and the quarterly economic benefits (the derivation of which is described below) to provide the same information provided by Xcel, but aggregated for each quarter.

10) **The utilities' written narratives on the benefits of the ancillary services market and the market's impact on their systems shall be formatted consistent with Xcel's and Minnesota Power's 4th quarter report in this docket.**

IPL and Xcel Energy exchanged ideas prior to completing the initial quarterly ASM report. It is IPL's belief that IPL and Xcel are using the same approach for calculating the benefits of the ASM. The main features of IPL's approach are an accounting analysis of the ASM-related transactions (charges and credits) with MISO, and an economic analysis of the benefits accrued because IPL is no longer required to "hold back" certain generators to provide ancillary services and is therefore enabled to gain margin on energy sales made by these generators. These margins accrue to the ratepayers through the operation of the FCA.

Details for all quarters are provided in Attachment E. The Q3 2014 ASM net benefit for IPL (total Company, including Iowa and Minnesota) of the accounting analysis and for the economic analysis is $288,248.58. This amount includes Contingency Reserve Deployment Failure charges of $3,643.33, Excessive / Deficient Energy Deployment Charge Amount of $147,402.93, and an allocation of 12.2 percent of MISO Schedule 17 Market Administrative charges in the amount of $65,956.28. The Q4 2014 ASM net benefit for IPL (total Company, including Iowa and Minnesota) of the accounting analysis and for the economic analysis is a net benefit of $299,739.18. This amount includes Contingency Reserve Deployment Failure charges of $2,622.88, Excessive / Deficient Energy Deployment Charge Amount of $165,963.21, and an allocation of 12.2 percent of MISO Schedule 17 Market Administrative charges in the amount of $81,131.47. The Q1 2015 ASM net benefit for IPL (total Company, including Iowa and Minnesota) of the accounting analysis and for the economic analysis is $260,058.39. This amount includes Contingency Reserve Deployment Failure charges of $-0-, Excessive / Deficient Energy Deployment Charge Amount of $93,103.95, and an allocation of 12.2 percent of MISO Schedule 17 Market Administrative charges in the amount of $94,648.88. The Q2 2015 ASM net benefit for IPL (total Company, including Iowa and Minnesota) of the accounting analysis and for the economic analysis is $249,796.71. This amount includes

Contingency Reserve Deployment Failure charges of $1,519.85, Excessive / Deficient Energy Deployment Charge Amount of $49,349.13, and an allocation of 12.2 percent of MISO Schedule 17 Market Administrative charges in the amount of $76,808.67. Details regarding the analysis of these two sources of costs and benefits (accounting and economic) are provided in the two following sections.

A. Accounting Cost Analysis

These are the direct accounting costs related to ASM and consist of charges for purchasing ancillary services from MISO and payments (or credits) by MISO for supplying ancillary services into the market. Over the course of the Q3 2014, IPL was a net purchaser of ancillary service from MISO. IPL sold $418,844.10 in ancillary services but purchased $437,005.75 in ancillary services, for a net excess of purchases over sales of $18,161.65. Over the course of the Q4 2014, IPL was a net seller of ancillary service to MISO. IPL sold $551.132.12 in ancillary services and purchased $548,363.67 in ancillary services, for a net excess of sales over purchases of $2,768.45. Over the course of the Q1 2015, IPL was a net purchaser of ancillary service from MISO. IPL sold $322,832.33 in ancillary services but purchased $356,443.36 in ancillary services, for a net excess of purchases over sales of $33,611.03. Over the course of the Q2 2015, IPL was a net seller of ancillary service to MISO. IPL sold $325,143.32 in ancillary services and purchased $318,973.82 in ancillary services, for a net excess of sales over purchases of $6,159.50. In total over the four quarters, IPL made net purchases of $42,834.73 for ancillary services. Attachment D provides monthly detail on the 12 charge types and the charge types are totaled on Attachment E Pages 1, 3, 5 and 7.

B. Economic Analysis of Benefits Accrued

A major source of benefits of the ASM is the elimination of the need to "hold back" low-cost coal-fired generating units on an individual utility basis, which was necessary prior to the start of the ASM in order to self-provide ancillary services. Due to holding back these units (prior to the ASM), IPL incurred an opportunity cost. The opportunity cost was the lost margin which resulted from not being able to offer in these low-cost units into the MISO energy market and thereby receive a payment which would have been higher than their fuel and operating costs. These potential lost margins must be reduced to account for IPL generators becoming unavailable to provide energy when they are awarded the opportunity to provide Regulation by MISO.[1]

Similar to Xcel, IPL has performed its economic analysis using two cases. For each case, the set of generators that IPL used prior to the ASM to supply regulation is analyzed. Using the same nomenclature as Xcel, Case A calculates the actual savings and costs for each generator in the ASM, and Case B calculates the costs for that generator if the period had been an energy-only market. Case B is the energy-only market baseline that would

[1] The ASM consists of three products: a) Regulation, b) Spinning Reserve, and c) Supplemental Reserve. Regulation is the highest-value product of the three products. IPL has limited its economic analysis (but not its accounting cost analysis) to the Regulation product. This is a conservative approach, as compared to also attempting to estimate the impacts of supplying the Spinning Reserve and Supplemental Reserve products.

have existed prior to the launch of the ASM. Case A shows the benefits made possible by the ASM.

While the analysis is performed on an hourly basis, for purposes of this report the results are aggregated for each quarter and reported on a quarterly basis. Attachment E (the sections titled Economic Analysis – Energy Savings Due to Not Holding Back Plants for Ancillaries) shows the results of this analysis for each quarter. The total benefit of no longer needing to hold back generators to provide regulation for Q3 2014 is $372,366.51. The total benefit of no longer needing to hold back generators to provide regulation for Q4 2014 is $378,102.20. The total benefit of no longer needing to hold back generators to provide regulation for Q1 2015 is $388,318.30. The total benefit of no longer needing to hold back generators to provide regulation for Q2 2015 is $320,435.88. The same table also shows the results of the accounting analysis to provide a total net accounting and economic benefit of $288,248.58 for Q3 2014, $299,739.18 for Q4 2014, $260,058.39 for Q1 2015 and $249,796.71 for Q2 2015.

The Company provides a description of how it calculates its economic opportunity costs and benefits here, and offers to share its spreadsheet used for the calculations with the Department or other interested parties upon request.

Prior to the ASM, IPL self-provided regulation at various times from eleven different generating units. Two of these units were IPL's gas-fired Emery units. If these units were deployed, they would be held back to provide regulation, which eliminated the need to hold back the following low-cost coal units (in the MW quantities shown): a) Ottumwa Generating Station (10 MW), b) Burlington Generating Station Unit 5 (10 MW), c) Neal Unit 3 (1.5 MW), d) Neal Unit 4 (1.5 MW), e) Louisa (1 MW), and f) Kapp Unit 2 (15 MW). Independent of whether the Emery units were deployed, the Lansing Unit 4 (8 MW) needed to be held back to provide regulation if it was operating.

For each hour, for the first set of generators in the paragraph above, for Case B (pre-ASM energy only market) the spreadsheet algorithms first determine whether an Emery unit is operating. If so, then the generator would not have been held back to provide regulation, so there would have been additional margin from energy sales. But if the Emery unit is not operating and the generator was operating for that hour, it would have been held back for regulation and was therefore not able to offer the held-back energy into the energy market to earn additional margin. In Case A (ASM), the only time the first set of generators would need to be held back would be if they were awarded to provide Regulation by MISO. They are then made available to earn additional margin on energy sales at all other times they are operating. The additional margin flows through the FCA to the benefit of the ratepayers.

For each hour for Lansing Unit 4 there is no test as to whether an Emery unit is operating, since Lansing Unit 4 is held back to provide regulation independent of Emery operations. In Case B (pre-ASM energy-only market), for each hour Lansing Unit 4 was dispatched (irrespective of Emery dispatch), it would have been held back to provide regulation. In contrast, in Case A (ASM), it would have been enabled to not hold back to supply regulation (unless it was awarded to provide Regulation by MISO), so the amount it had held back previous to the ASM is added back, which also produces margin that flows through the FCA.

There is an additional adjustment affecting all of the generators. The algorithm includes a logical test to ensure that the calculated amount of energy available for offer in Case A, including any amounts of Regulation awarded by MISO, is not less than the minimum operating output (known as RegMin) of the unit.

11)The utilities shall file detailed and specific explanations for all Contingency Reserve Deployment Failure and Excess/Deficient Energy Charges incurred, including an explanation as to why they should be recovered and what actions the utility took to minimize these charges.

Please refer to Attachment F for a list of the CRDF charges incurred by IPL during July 2014 - June 2015. Total charges to IPL were $7,786.05 during this period. All but $196.20 of these charges are associated with four instances when the Emery combined cycle units were transitioning from the steam unit-only operation to steam unit plus duct burners operation. The MISO Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) market clearing processes will only accept a single ramp rate for a combined cycle combustion turbine, which is a flaw that IPL has been advocating for MISO to correct since at least 2010, and which MISO intends to correct with IT system enhancements in the future. When adding the duct burners, the steam unit ramp rate is less than when the steam unit is operating by itself. The units were operating to provide energy, when MISO called on the units for additional output for spinning reserve during the instances when the transition was occurring on these four occasions, and the units were not able to respond timely. The other CRDF event was a 7.7 MW shortfall for spinning and supplemental reserve deployment at Burlington Generating Station, which was due to a unit de-rate and the unit being near its maximum output when called upon. The CRDF charge in that instance was $196.20. Considering there were only these minor CDRF events over the course of the year, and the vast majority of the charges are due to a MISO SCUC/SCED processing flaw, IPL should be allowed to recover the CRDF charges in its rates.

Excessive/Deficient Energy Deployment Charge Amount charges incurred by IPL during July 2014 – June 2015 continued to be higher than before MISO changed its tariff to implement Regulation Mileage effective on Dec. 17, 2012. MISO's implementation of Regulation Mileage was prompted by FERC Order 755, which required Regional Transmission Organizations to modify the way generators are paid for providing Regulation. Previously, generators were paid for making Regulation available, without any consideration of how accurately the Regulation-providing units responded when called upon for Regulation. FERC required the implementation of Regulation Mileage to reward units that are able to provide Regulation more efficiently than other units. Examples of such assets include flywheels, which are specifically designed to provide Regulation rather than energy. If a unit that is cleared for Regulation is not able to follow Regulation dispatch signals within very tight tolerances, there are charges related to Regulation Mileage which are settled using the Excessive/Deficient Energy Charges. It should be noted that the charges recovered from the generators are used by MISO to reduce charges to load, through socialization. This reduction in load cost appears in settlement statements on the Real Time Regulation Cost Distribution Charge type.

IPL does not have any flywheels to provide Regulation, nor are there any generator owners within MISO that have flywheels. Therefore, IPL still offers and is awarded to provide Regulation, but its assets are not perfectly suited to meet the Regulation Mileage criteria and they have therefore been assessed EDEC charges. For perspective, all EDEC charges for the 2011-2012 AAA year amounted to $42,761.13. This approximate pattern held for the first five months of the 2012-2013 AAA year, with monthly charges that ranged from $1,952.53 to $5,991.63 per month. But since the tariff change was made in December 2012, EDEC charges for the remainder of the 2012-2013 AAA year averaged $65,722.20 per month. During the 2013-2014 AAA year, EDEC charges averaged $54,449.66 per month, for a total of $653,395.90 EDEC charges for the AAA year. As IPL has continued to cease offering its less responsive generators for Regulation over time in order to avoid the EDEC charges, EDEC charges have continued to decrease, averaging $37,984.94 per month (or a total of $455,819 for the 2014-2015 AAA year. In addition to the total annual decline, the charge amounts have been significantly decreased during the last two quarters of the 2014-2015 AAA year: Q3 2014 - $147,403; Q4 2014 - $165,963; Q1 2015 - $93,104; Q2 2015 - $49,349.

IPL and other MISO generator owners still need to offer their units in for Regulation. There are no flywheel or any other types of units within the MISO market that are extant that could provide the Regulation that is currently offered by more traditional units. If IPL and other generator owners did not offer in Regulation, system reliability would not be sustainable. Therefore, the Commission should allow recovery of the EDEC charges.

12) The utilities shall clearly identify and separately list in their automatic adjustment reports all ancillary services market values included in those reports and/or passed through the Fuel Clause Adjustment.

See Attachment C.

INTERSTATE POWER & LIGHT COMPANY
Minnesota Public Utilities Commission Order in Docket Nos. E-999/AA-09-961 and E-999/AA-10-884
Responses to Information Requested in Order

April 6, 2012 - Order Acting on Electric Utilities' Annual Reports and Requiring Additional Filings

8) **Interstate, Minnesota Power, Otter Tail, and Xcel shall report in future AAA filings any offsetting revenues or compensation recovered by the utilities as a result of contracts, investments, or expenditures paid for by their ratepayers. If any offsetting revenues and/or compensation are not credited back to a utility's ratepayers through the fuel clause, the IOUs shall clearly identify such revenue or compensation by source and amount and fully justify their action in the relevant AAA filings.**

IPL included a total of $30,039,398 in offsetting revenues and credits in the Fuel Cost Adjustment (FCA) for the period July 2014 through June 2015. These included all Midwest Independent Transmission System Operator, Inc. revenues, and inter-system sales revenues to other parties, such as the PJM Market and miscellaneous risk management sales. IPL also includes a credit entitled "Steam Transfer" for the amount of fuel costs assigned to the steam utility related to the generation of export steam provided to steam utility customers. For example, IPL includes all allowable coal expenses in the FCA but then credits as "Steam Transfer," the portion of coal expenses which were used to generate the steam. IPL also had a small credit for emission allowances.

IPL includes all offsetting revenues and credits in the monthly FCA filings. See Attachment G.

13) **Interstate shall explain in future filings why it does not have economic generation resources comparable to other utilities in the MISO footprint and explain how this effects what happens when there are outages on its system.**

IPL is responding to this request for information made by the Commission in its order dated April 6, 2012 in Docket Nos. E-99/AA-09-961 and E-999/AA-10-884. Those dockets covered the 2008-2009 and 2009-2010 AAA periods. IPL provided the requested information in the 2011-2012 AAA filing in Docket No. E-999/AA-12-757. IPL provided the following information in the 2012-2013 AAA filing in Docket No. E-999/AA-13-599. Due to the timing of the response to the IPL's 2012-2013 AAA filing by the Minnesota Department of Commerce (Department), which is expected to be completed after IPL is required to file the instant AAA information, the information filed for the 2012-2013 AAA filing is repeated herein. The rate per kiloWatt hour for the various Minnesota utilities shown in the table below is obtained from the Department's response to the utilities' AAA filings, so based on the timing described above, it is not possible for IPL to update the table at this time.

IPL maintains that the appropriate proceedings to examine the Company's average cost of energy are the Integrated Resource Plan proceedings. IPL notes that the Commission did not issue an order point on this issue in its order in Docket No. E-999/AA-11-792 and the Department did not address this issue in its comments in Docket No. E-999/AA-12-757, following information that was provided by IPL in the 2011-2012 AAA filing.

For reference, and to avoid the need to retrieve this information, below is the text of IPL's response to the request for information, as filed in Docket No. E-999/AA-12-757:

IPL posits that the appropriate proceeding to review IPL's generation resources and whether those resources are economic is the Integrated Resource Plan proceeding before the Commission. The Department states the same, in its Response Comments submitted on December 30, 2011 in Dockets No. E999/AA-09-961 and E999/AA-10-884, in its "Issues to be Addressed in Future Supplemental Reporting for FYE11 AAA," wherein it states:

> *"The Department remains concerned about the current status of IPL's generation fleet and the Company's lack of progress towards replacing aging resources. The Department looks forward to reviewing the company's economic and reliability analysis of any DAEC PPA renewal and the alternatives considered by IPL in Docket No. E001/RP-08-673." (Page 28)*

The average cost per kilowatt-hour is of interest to the Department and the Commission in an AAA filing. The Department produces the cents per kilowatt-hour for each of the Minnesota utilities for each AAA year and includes the information in its report to the Commission. Below is a table that shows these values for each Minnesota investor-owned utility since the start of the MISO energy market in 2005. The table demonstrates that over this period, IPL has had the second lowest average cost per kilowatt-hour among the four utilities compared, and is in the same position for the most recently-available year (AAA FYE 11).

Cents/kWh	*MP*	*OTP*	*IPL*	*Xcel*
FYE06	*1.580*	*2.602*	*2.339*	*2.292*
FYE07	*2.178*	*2.695*	*2.390*	*2.664*
FYE08	*2.037*	*2.805*	*2.085*	*2.777*
FYE09	*1.702*	*2.479*	*2.405*	*2.648*
FYE10	*1.924*	*2.310*	*2.422*	*2.489*
FYE11	*2.018*	*2.245*	*2.196*	*2.602*
Source: Docket No. E999/AA-11-792 Minn. Dept. of Commerce, Review of 2010-2011 (FYE11) Annual Automatic Adjustment Reports For Electric Utilities, June 1, 2012, Table 7 (Page 48)				
Cents/kWh	*MP*	*OTP*	*IPL*	*Xcel*
Average	*1.907*	*2.523*	*2.306*	*2.579*

If not already addressed in the 2012-2013 AAA proceeding, IPL repeats its request (made in the 2012-2013 AAA proceeding) that the Commission make a determination in this docket as to whether IPL is required to address this issue in future AAA filings.

22) **Interstate shall provide in future AAA reports, a simple annual identification of forced outages and a short discussion of how such outages could have been avoided or alleviated.**

The requested identification and discussion of forced outages is provided in Attachment I. In addition, please note the general comments regarding the most common cause of forced outages in the IPL fleet provided in the 2011-12 AAA filing in Exhibit H pages 24 and 25, and in IPL's response to Docket E-999/AA-11-792; information request numbers 127 and 128.

28) **Interstate, Minnesota Power, Otter Tail, and Xcel shall continue to provide a comparison and reconciliation of the MISO accredited value of their generators using MISO accredited UCAP values and integrated resource plan capacity ratings in future AAA filings. This comparison and reconciliation should be prepared in sufficient detail to allow the Department to understand: (a) the impacts of generation resources that are not network deliverable (i.e., not interconnected), and (b) the possible constraints of utilities' systems and the impact of those constraints.**

See Attachment A which reflects the Zonal Resource Credit (ZRC) provisions under the current MISO Resource Adequacy (RA, also known as Module E) construct. This shows how the interconnection service (Deliverability) values and annual Generator Verification Test Capacity (GVTC) test results are part of the development of the Unforced Capacity (UCAP) MWs. In turn, the UCAP MWs can be converted into ZRCs. The column titled "adj UCAP" of Attachment A reflects the resulting ZRCs for IPL during MISO RA Planning Year (PY) 2014/2015 (which ran from June 1, 2014 through May 31, 2015).

It was the comparable ZRCs from data assembled previous to the MISO PY 2014/2015 auction that were the basis for the planning capacity values used in the 2014 Integrated Resource Plan (IRP), along with future changes that were projected at the time that the IRP was being developed. The tie out to 2014 capacity data in IRP Appendix 10A and Appendix 10C is shown in the column titled "IPL 2014 IRP" of Attachment A and in the associated notes at the bottom of the attachment.

The following describes the differences between the resources shown in IPL's IRP Appendix 10A/10C and those shown in Attachment A:

General: Minor variations in UCAP on 6 of 45 generating units as a result of evolving values before the auction. IPL's 2014 IRP was filed in March of 2014, so preliminary UCAP data was utilized in approximately January to complete the IRP. The total variation due to the evolving UCAP values between January 2014 and the end of March Planning Resource Auction is only 2.2 UCAP on a 2,900 UCAP basis, or about 0.1%.

DAEC: The IRP listed the DAEC purchase, however Attachment A reflects it at the bottom of the "IPL 2014 IRP, 2014 year" column for completeness, as per the MISO RA process this is reflected as a ZRC transfer and not within their ZRC development table.

INTERSTATE POWER & LIGHT COMPANY
Minnesota Public Utilities Commission Order
in Docket No. E-999/AA-11-792
Responses to Information Requested in Order

August 16, 2013 – Order Acting on Electric Utilities' Annual Reports, Requiring Refund of Certain Curtailment Costs, and Requiring Additional Filings

18) The electric utilities shall provide in the initial filing of all future electric AAA reports the Minnesota jurisdictional Schedule 10 costs together with the allocation factor used to support for why the allocator is reasonable. Additionally, the electric utilities shall provide information to support increases in MISO Schedule 10 costs of five percent or higher over the prior year's costs, including an explanation of benefits received by customers for these added costs.

See Attachment H.

Production (non-energy portion) and transmission costs are allocated to state jurisdictions on the basis of System Coincident Peak (SCP). SCP is an appropriate allocator because generation and transmission facilities are designed to serve peak load and SCP is the best indicator of system load. The use of the SCP allocator for generation and transmission costs is consistent with IPL's last three Minnesota retail electric rate cases.

MISO Schedule 10 charges allow MISO to recover the costs associated with operating the independent system operator (ISO). Such costs include, but are not limited to, operations planning, maintenance coordination, billing and settlements, scheduling, reliability coordination, transmission planning and tariff administration. These costs are recovered through Schedule 10 and are applied to all transmission customers, such as IPL, across the MISO footprint. The costs are allocated through demand and energy rates. For the period of July 2014 through June 2015 total MISO Schedule 10 charges were greater than 5% higher as compared to the prior year's period. The comparable average rates per unit of demand and energy were higher in part due to relatively lower demand and load factors in this period as compared to the July 2013 through June 2014 period. The increase would also be impacted, in part, due to changes in MISO's operating costs charged through MISO Schedule 10.

20) The Beginning with the fiscal year 2012 AAA filing, to assist the Department with its plans to do a more detailed review of congestion paths, including related costs and revenues in the fiscal year 2012 AAA, the electric utilities shall:

a. Provide hourly data on Day-Ahead Locational Marginal Price (LMP) basis, including energy, line losses, and congestion charges for each generation node, each load node, and Minnesota Hub for the current AAA period. The Department requests that utilities send

this data to the DOC in Access file format and include a separate reference guide defining all column headers.

IPL will work with the Department to provide an Access file which includes the requested information. **[Trade Secret Data Begins** [redacted] **Trade Secret Data Ends]**

The column headers are defined as:

Date – Day of the AAA year.
HE – Hour ending. HE 1 is the first hour of the day.
CP Node – Commercial pricing node.
DAMEC – Day ahead marginal energy component.
DAMCC – Day ahead marginal congestion component.
DAMLC – Day ahead marginal loss component.
DALMP – Day ahead locational marginal price.

b. **Perform the following analysis based on the above requested data:**

i. **Identify hours in which congestion costs are incurred between a generation node and load node (path);**

ii. **Sum the qualifying congestion costs by path (multiplying MW times difference in Marginal congestion costs Mcc for each path); and**

iii. **Identify the ten paths with the highest amount of congestion costs for the current AAA period.**

See Attachment J.

c. **Include the ten paths identified above and the total of their congestion costs. For each path, also answer the following questions:**

i. **What is the Company's Financial Transmission Rights (FTRs) hedging positions and Auction Revenue Rights (ARRs) for these ten paths?**

[Trade Secret Data Begins [redacted]

[redacted]

[redacted] **Trade Secret Data Ends]**

ii. **Identify all FTR revenues, ARR revenues, congestion expenses, and the resulting net congestion cost or revenue for these ten paths.**

See Attachment J.

iii. **Based on the Company responses to a, b, and c.i. and c.ii., what cost effective improvements could be considered to reduce the congestion amounts for the identified paths?**

[Trade Secret Data Begins [redacted]

Trade Secret Data Ends]