Alliant Energy Corporate Service
Legal Department
319-786-4742 – Phone

Paula N. Johnson
Senior Attorney - Regulatory

Interstate Power and Light Company
An Alliant Energy Company

Alliant Tower
4902 North Biltmore Lane
P.O. Box 77007
Madison, Wisconsin 53707-1007

Office: 1.800.822.4348
www.alliantenergy.com

March 31, 2014

Dr. Burl W. Haar
Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

RE: Interstate Power and Light Company
Docket No. E001/RP-14-77
2014 Electric Integrated Resource Plan

Dear Dr. Haar:

Interstate Power and Light Company (IPL) hereby submits via eFiling its 2014 Electric Integrated Resource Plan (Resource Plan or IRP) filing to the Minnesota Public Utilities Commission (Commission) pursuant to the Commission's *Order Finding Baseload Diversification Study in Compliance with 2012 Resource Plan Order, Setting Date for New Resource Plan, and Setting Further Requirements* issued on May 13, 2013. The Resource Plan identifies how IPL proposes to meet the capacity and energy needs of its customers over the 2015-2029 planning period.

IPL has made significant investments in its generating fleet to position it for market competitiveness, reliability and compliance with state and federal guidelines. As a result, IPL is well-positioned to provide reliable and cost-effective service into the future through existing and expected investments in its owned and acquired generation fleet, which includes renewable energy, and energy efficiency opportunities. IPL is currently investing in approximately:

- 450 megawatts (MWs) of wind power;
- 400 MWs from nuclear under a purchased power agreement;
- 2,500 MWs of existing fossil fuel (coal and natural gas) power;
- Demand Side Management (DSM) goals approved by the Commission; and
- 650 MW Marshalltown Generating Station Combined Cycle facility (MGS) with a scheduled 2017 in-service date.

These investments have placed IPL in a good position to provide reliable and economical service into the future and at the same time keeps customers' rates as low as possible.

IPL intends to continue its proactive approach through planned retirement of certain older, smaller and less efficient intermediate steam units and peaking units in the next five years rather than taking a reactionary approach. These and other steps are discussed in the five-year action plan.

IPL will continue to work with stakeholders to ensure that its Resource Plan is thoroughly understood and implemented effectively. Implementation of this Resource Plan will allow IPL to meet customer needs, significantly reduce carbon and other emissions, and maintain reliable service at reasonable rates. IPL welcomes dialogue with stakeholders and looks forward to the Commission's consideration of its Resource Plan.

Copies of the Resource Plan have been served on the Minnesota Department of Commerce, Division of Energy Resources, and the Minnesota Office of Attorney General – Residential Utilities and Small Business Division. Additionally, as reflected on the attached Affidavit of Service, the IPL 2014 IRP Non-Technical Summary has been served on IPL's official general service list and the 2008 IRP service list (*see* Docket No. E001/RP-08-673).

Respectfully submitted,

/s/ Paula N. Johnson
Paula N. Johnson
Senior Attorney - Regulatory

PNJ/tao
Enclosures

cc: Service List
Steve Rakow

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	**Chair**
David C. Boyd	**Commissioner**
Nancy Lange	**Commissioner**
Dan Lipschultz	**Commissioner**
Betsy Wergin	**Commissioner**

IN THE MATTER OF INTERSTATE POWER AND LIGHT COMPANY'S 2014 INTEGRATED RESOURCE PLAN	**DOCKET NO. E001/RP-14-77**

AFFIDAVIT OF SERVICE

STATE OF IOWA)
) ss.
COUNTY OF LINN)

Tonya A. O'Rourke, being first duly sworn on oath, deposes and states:

That on the 31st day of March, 2014, copies of the foregoing Affidavit of Service, together with Interstate Power and Light Company's, 2014 Electric Integrated Resource Plan, were served upon the parties on the attached service list, by e-filing, overnight delivery, electronic mail, and/or first-class mail, proper postage prepaid from Cedar Rapids, Iowa.

/s/ Tonya A. O'Rourke
Tonya A. O'Rourke

Subscribed and Sworn to Before Me
this 31st day of March, 2014.

/s/ Kathleen J. Faine
Kathleen J. Faine
Notary Public
My Commission Expired on February 20, 2015

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Bobby	Adam	bobby.adam@conagrafoods.com	ConAgra	Suite 5022 11 ConAgra Drive Omaha, NE 68102	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Michael	Bradley	mike.bradley@lawmoss.com	Moss & Barnett	Suite 4800 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
City	Clerk	sschulte@ci.albertlea.org	City of Albert Lea	221 E Clark St Albert Lea, MN 56007	Paper Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Ian	Dobson	ian.dobson@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
David	Grover	dgrover@itctransco.com	ITC Midwest	444 Cedar St Ste 1020 Saint Paul, MN 55101-2129	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Paula N.	Johnson	PaulaJohnson@alliantenergy.com	Interstate Power and Light Company	200 First Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Jim	Krueger	jkrueger@fmcs.coop	Freeborn-Mower Cooperative Services	Box 611 Albert Lea, MN 56007	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Steven	Nyhus	swnyhus@flaherty-hood.com	Flaherty & Hood PA	525 Park St Ste 470 Saint Paul, MN 55103	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Larry L.	Schedin	Larry@LLSResources.com	LLS Resources, LLC	12 S 6th St Ste 1137 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Matthew J.	Schuerger P.E.	mjsreg@earthlink.net	Energy Systems Consulting Services, LLC	PO Box 16129 St. Paul, MN 55116	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Ron	Spangler, Jr.	rlspangler@otpco.com	Otter Tail Power Company	215 So. Cascade St. PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	Yes	OFF_SL_8-673_1
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_8-673_1
Elizabeth	Goodpaster	bgoodpaster@mncenter.org	MN Center for Environmental Advocacy	Suite 206 26 East Exchange Street St. Paul, MN 551011667	Electronic Service	Yes	OFF_SL_8-673_1
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_8-673_1
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	Yes	OFF_SL_8-673_1
Kent	Ragsdale	kentragsdale@alliantenergy.com	Alliant Energy-Interstate Power and Light Company	P.O. Box 351 200 First Street, SE Cedar Rapids, IA 524060351	Electronic Service	Yes	OFF_SL_8-673_1
Marya	White	mwhite@misoenergy.org	MISO	1125 Energy Park Dr St. Paul, MN 55108	Electronic Service	No	OFF_SL_8-673_1

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	**Chair**
David C. Boyd	**Commissioner**
Nancy Lange	**Commissioner**
Dan Lipzhultz	**Commissioner**
Betsy Wergin	**Commissioner**

IN THE MATTER OF INTERSTATE POWER AND LIGHT COMPANY'S 2014 INTEGRATED RESOURCE PLAN	**DOCKET NO. E001/RP-14-77**

STATEMENT PROVIDING JUSTIFICATION FOR TRADE SECRET INFORMATION

Pursuant to the Minnesota Public Utilities Commission's (Commission) revised procedures for Handling Trade Secret and Privileged Data and Minn. Stat. §13.37 and Minn. Rule Pt. 7829.0500, Interstate Power and Light Company (IPL) has marked specific information contained within its 2014 Electric Integrated Resource Plan (Resource Plan) as Trade Secret.

IPL is providing a non-public version of its Resource Plan that contains trade secret information, as defined by section 13.37, subd. 1(b) of the Minnesota Statutes, in that the information is the subject of efforts by IPL that are reasonable under the circumstances to maintain its secrecy, and that derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. IPL has marked the information pursuant to the Minnesota Public Utilities Commission's Revised Procedures for Handling Trade Secret and Privileged Data, Minn. Rule Pt. 7829.0500.

A small number of people currently have knowledge of this information, which is not available from public sources, and IPL makes consistent efforts to maintain the confidentiality of the information. The information has substantial value to IPL, and would be of substantial value to IPL's competitors for various purposes. Should the information fall into the hands of IPL's competitors, it could be used to create a competitive disadvantage for IPL, resulting in higher costs to IPL's customers.

Accordingly, IPL believes the above identified information contained in IPL's Resource Plan meets the definition of trade secret under Minn. Stat. §13.37.

IPL 2014 IRP Non-Technical Summary

The following Non-Technical Summary provides a high level description of Interstate Power and Light Company's (IPL) 2014 Electric Integrated Resource Plan (RIP, Resource Plan) and factors affecting the 2014 IRP. In doing so, this Non-Technical Summary describes IPL's resource needs, the resource plan IPL has created to meet those needs, the process and analytical techniques used to create the plan, activities required over the next five years to implement the plan, and the likely effect of plan implementation on electric rates and bills.

Strategic Electric Integrated Resource Planning

IPL's Strategic Plan is built upon three primary elements: competitive cost, reliable service, and balanced generation. Accordingly, IPL provides energy service in a manner that values the environment, safety, reliability, and its customers' financial concerns. IPL's strategy corresponds to the Minnesota Public Utilities Commission's Minn. Rule 7843.0500 Subp. 3, which requires utility resource plans be evaluated on their ability to:

a. maintain or improve the adequacy and reliability of utility service;
b. keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints;
c. minimize adverse socioeconomic effects and adverse effects upon the environment;
d. enhance the utility's ability to respond to changes in the financial, social, and technological factors affects its operations; and
e. limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control.

IPL's Strategic Plan solidifies the foundation for IPL's commitment to providing its customers and communities with safe, efficient and reliable energy. It also stresses IPL's role in preparing for a carbon-constrained future while moderating the cost impact on its customers through continued investment in renewable energy, proven technologies and energy efficiency.

The Strategic Plan's focuses on themes that are integral to thoughtful and effective Electric Integrated Resource Planning: competitive costs; reliable service; balanced generation; and environmental stewardship. Balanced generation includes managing IPL's generating fleet to produce cost effective energy for its customers, reduce reliance on market purchases as well as a strong commitment to renewable energy, while continuing to focus on customers' economic concerns.

IPL consistently follows its Strategic Plan when making key decisions, including decisions relating to resource planning, delivering energy, and operating its generating fleet. IPL identifies decisions to be made, gathers relevant information, examines alternatives, weighs potential outcomes and chooses the alternative that best fits the strategy. Once an alternative is selected, IPL emphasizes the effective execution of its decision in a manner consistent with the Strategic Plan. This approach has been adhered to in the preparation of this IRP.

Pending Sale

IPL has entered into an agreement with Southern Minnesota Electric Cooperative (SMEC) for the transfer to SMEC of IPL's electric distribution assets and operations in Minnesota (the Transaction). As part of the Transaction, SMEC and IPL will enter into an agreement under which IPL will provide to SMEC all of the electric power needed to serve customers in the area in Minnesota to be transferred from IPL to SMEC. Consents have been obtained from the suppliers of electric power to the individual SMEC distribution cooperatives for IPL to provide that power for 10 years to the areas to be acquired from IPL, which will be included in the record in the IRP if requested. As a result, IPL does not expect its total load to be materially affected by the Transaction for that time period. The application for approval of this Transaction has not been filed with the Commission, but filing of the application is expected in the next few weeks. The Load Forecast is based on the status quo and assumes continued service to the Minnesota jurisdiction over the entire study period. IPL's Low Load Forecast covers a bandwidth of potential load uncertainties. Additionally, there are significant supply-side retirements and expirations after 10 years to which IPL must react, that appear more significant than 10 year load uncertainties (see Figure 1 below).

Investments by IPL

IPL has made significant investments in its generating fleet to position it for market competitiveness, reliability and compliance with state and federal guidelines. As a result, IPL is well-positioned to provide reliable and cost-effective service into the future through existing and expected investments in its owned and acquired generation fleet, which includes renewable energy, and energy efficiency opportunities. IPL is currently investing in approximately:

- 450 megawatts (MWs) of wind power;
- 400 MWs from nuclear;
- 2,500 MWs of existing fossil fuel (coal and natural gas) power;
- Demand Side Management (DSM) goals approved by the Minnesota Public Utilities Commission (Commission); and
- the approximate 650 MW Marshalltown Generating Station Combined Cycle facility (MGS) with a scheduled 2017 in-service date.

This IRP reflects opportunities to continue providing reliable, cost-competitive and environmentally responsible energy and capacity to IPL customers. IPL recognizes that, due to the dynamic nature of the economy and the utility industry, it must remain flexible and balanced in the IRP. Accordingly, IPL's 2014 IRP considers a wide variety of analytical, market and policy issues and presents a plan which continues to meet customer's needs in a cost-competitive, reliable, and environmentally sound manner.

IRP Summary

To assist in understanding the key components of its 2014 IRP, IPL provides the following highlights. A summary of IPL's 2014 IRP Development can be found in Section 1. Highlights of this IRP include:

Demand and Energy Forecast

IPL has modeled a low and high load forecast in its analysis, in addition to its base forecast, because load forecasts can never provide complete certainty due to economic and policy changes. As in previous IRPs, IPL's load forecasts are based on statistical regression analysis to predict electricity use based on historic trends, forecasts of economic activity, and forecasts of population growth.

The 2014 IRP reflects a lower energy forecast compared to the 2010 IRP due to lower short-term growth rates. The 2014 IRP reflects a higher energy forecast than the Baseload Diversification Study (2012 IRP) due to the retention of a large wholesale load and some large customer expansions. The 2014 IRP reflects a higher peak demand forecast than the 2010 IRP and Baseload Diversification Study (2012 IRP) mainly due to recent higher actual demands, as well as a large wholesale retention and large customer expansions.

Fuel Price Forecasts

As in the 2010 IRP and Baseload Diversification Study (2012 IRP), IPL utilized fuel price projections provided by the Wood Mackenzie consulting service. Analyses were performed on a wide range of coal and natural gas prices. The price forecasts for Natural Gas, On Peak Market Energy, and Off Peak Market Energy are lower in the 2014 IRP than in the 2010 IRP and Baseload Diversification Study. The 2014 IRP coal price forecast is similar to the 2010 IRP and Baseload Diversification Study (2012 IRP), except that the 2014 IRP escalation rates for 2029-2035 are much higher than the 2010 IRP.[1]

Greenhouse Gas Regulation

The 2014 IRP recognizes potential future greenhouse gas regulation, including compliance with Commission requirements, is a significant issue. IPL gives this issue serious consideration by modeling its various sensitivity cases under three different sets of carbon dioxide (CO_2) cost scenarios: (i) the No Carbon scenario; (ii) the Wood Mackenzie 2023 Carbon scenario; and (iii) the Minnesota Midpoint 2017 Carbon scenario. Further, IPL varied the Minnesota Carbon costs to a low \$9/ton range and a high \$34/ton range. While these CO_2 assumptions significantly drive Present Value Revenue Requirements (PVRR) in the 2014 IRP, the expansion plans are similar.

[1] Wood Mackenzie's coal forecast assumes an increase in exports to China.

Status of Coal-fired Units

Increased pressure from environmental regulations requires changes to IPL's coal fleet. Near term steps pertaining to IPL's coal fleet are outlined in the Five Year Plan section of this IRP. The near term steps are generally based on the plan outlined in IPL's 2010 IRP. IPL's 2010 IRP proposed to retire IPL's oldest, smallest, least efficient (Tier 3) coal-fired units, and proposed capacity and efficiency upgrades at IPL's newer, larger, more efficient (Tier 1) coal-fired units. IPL is also investing in significant emissions controls on its Tier 1 units (also an assumption in the 2010 IRP).

IPL's remaining units (Tier 2) were analyzed in IPL's Baseload Diversification Study[2]. Several plans were reviewed covering retirement, gas conversions, and continued coal-fired operation with emissions control projects.

Long term, these units continue to be evaluated and current plans may be subject to revision. [TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

Status of Existing Peaking and Intermediate Units

IPL has an aging generation fleet, including in particular several intermediate steam units and peaking units. Although these units have delivered safe, reliable service to customers for decades, these units would require significant investment to continue long term operation, and it does not appear to be cost effective for IPL's customers to invest further in these units. IPL currently intends to retire these older, smaller and less efficient units in the next five years to provide a planned orderly shutdown, as opposed to a reactionary approach. This approach offers cost certainty by moderating unforeseen potential repair costs on older facilities, and allows adequate time to:

- effectively and efficiently replace the generating capacity on behalf of IPL customers;
- work with Midcontinent Independent Transmission System Operator, Inc. (MISO) and transmission owner ITC Midwest LLC (ITC-M) to address any potential grid reliability issues that could adversely impact customers; and

[2] IPL's Baseload Diversification Study was filed in Docket No. E001/RP-08-673 on December 3, 2012.

- develop and execute an effective plan for shutdown and decommissioning of these units as well as assisting employees affected by unit retirements.

These planned plant retirements are contingent upon receiving MISO determination that the resources are not needed for system reliability.

Status of Nuclear Agreements

In the 2014 IRP Electric Generation Expansion Analysis System (EGEAS) modeling, IPL included the 400 MW Power Purchase Agreement (PPA) renewal from the Duane Arnold Energy Center (DAEC) for 2014-2025, and continued extension of the PPA through the licensed life (2033). IPL presumes that as long as the plant continues to run, IPL is a potential buyer. However, pricing is of particular concern and will need to be negotiated. IPL anticipates that, similar to the efforts taken in previous years which resulted in a Request for Proposals, it will undertake similar bidding processes to ensure competitive value for customers before the expiration of the current PPA.

Plan Development, Process and Analytical Techniques

IPL's 2014 IRP begins with a projection of customer demand and energy over the planning horizon. The calculation of IPL's energy forecast starts with a trended forecast of the number of meters. Forecasted meters are then multiplied by the results from a regression model of use per meter. The resulting forecasted values are then added to specific large customer forecasts, compared with recent historical class level sales, and adjusted for external factors. Forecasts of IPL's smaller classes are also added. Finally, estimated transmission and distribution losses are applied to arrive at the energy forecast. For the longer term 2019-2029 forecast, IPL applied the growth rate from the regression model.

To forecast demand, IPL uses Theoretical Demand (the highest observed load plus the estimated interrupted and Direct Load Control (DLC) called during the peak time). Next, IPL reduces the Theoretic Demand by the load attributed to the large customers which are forecasted individually. The remaining customers are forecasted using a consensus of three different regression models. The three models represent annual peak, monthly peaks, and summer seasons. The annual and summer seasonal models are averaged to arrive at an annual peak forecast. The annual forecast is then calendarized based on the monthly model. The individually forecasted customer peaks are added to the modeled results to arrive at the demand forecast. Finally the demand forecast is compared with the corresponding energy model for reasonability. In the current plan, due to divergent growth rates between demand and energy, the growth rate of the demand forecast was adjusted to match the growth rate from the energy forecast.

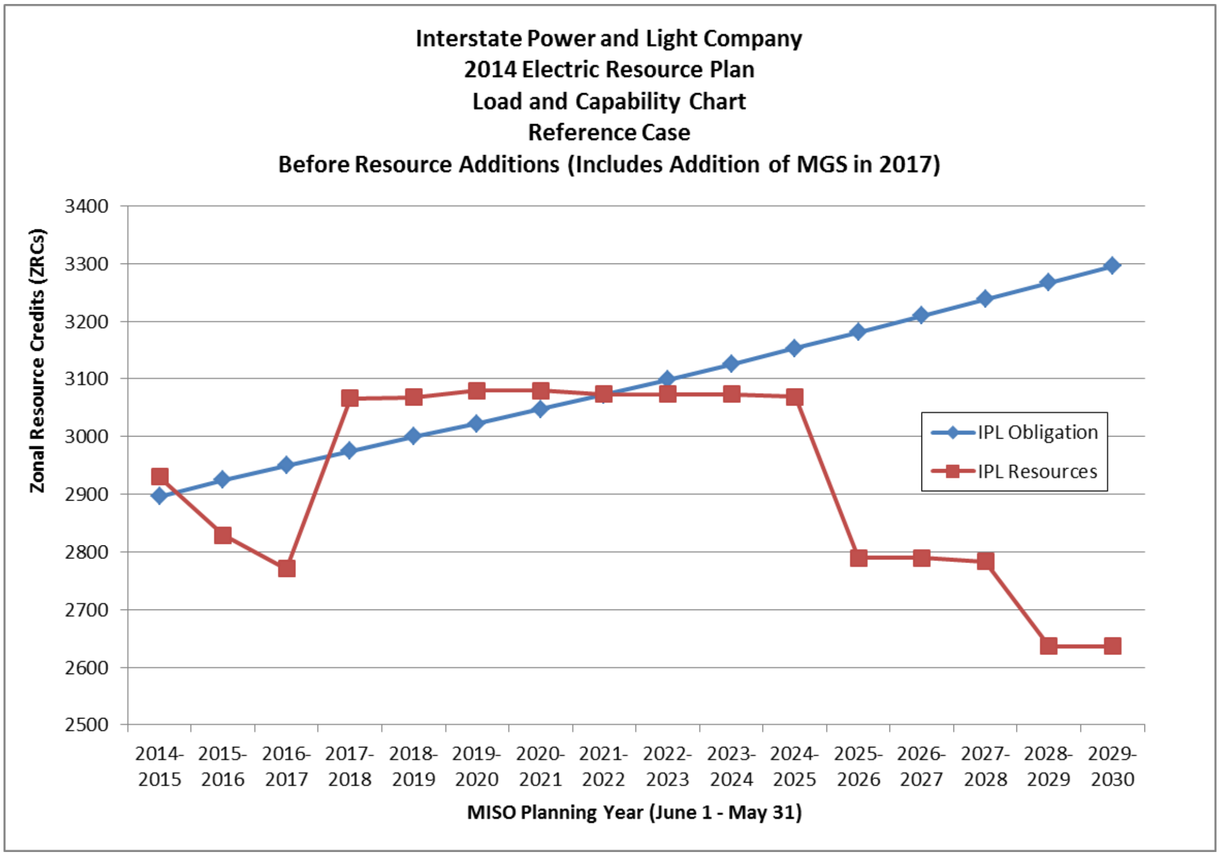
Consistent with previous IRPs, IPL has used the EGEAS computer simulation model to explore how best to meet the generation demands identified in its forecast. The ultimate goal is to moderate cost, maintain reliability and moderate risk. Given reasonable assumptions and after careful consideration of costs, reliability and risks, a reference case is constructed. Using the identified reference case, IPL explores additional scenarios by changing various input assumptions and resource selections. This modeling information provides a foundation to assess how different assumptions, scenarios and sensitivities affect IPL's resource needs.

Resource Needs

IPL faces an expected capacity shortfall for 2015 and 2016. In 2017, MGS is expected to be in-service, relieving capacity shortfalls through 2021. For 2022 through 2024, there is a small projected shortfall, essentially due to load growth. After 2024, significant shortfalls of several hundred Zonal Resource Credits (ZRCs)[3] are shown through the end of the study period. This is a result of load growth, retirement of existing coal units, and retirement of existing peaking units. Figure 1 summarizes IPL's load and capability before resource additions:

[3] ZRCs are essentially accredited capacity units under the MISO's capacity auction. A ZRC is equal to one MW of unforced capacity (UCAP) from a planning resource for a given zone during a specific planning year, as described in the requirements set forth in Module E of the MISO Tariff.

Figure 1: IPL's 2014 IRP Load and Capability Projection – Before Resource Additions



Five-Year Action Plan

The resources needed to meet IPL's system capacity and energy requirements come primarily from two types of resources; demand-side and supply-side. Additionally, IPL must satisfy Renewable Portfolio Standards (RPS) in Minnesota and Iowa. During the forthcoming years, IPL will:

- Continue to pursue DSM activities;
- Investigate and pursue renewable energy alternatives, including wind and solar;
- Purchase capacity in the short term to satisfy MISO Resource Adequacy obligations;
- Complete construction of the approximate 650 MW MGS combined cycle facility;
- Pursue capacity and efficiency upgrades at Tier 1 coal-fired units;
- Pursue reasonable emission controls and/or natural gas conversions on its remaining coal-fired units;
- Retire older peaking units;
- Retire older intermediate steam units;
- Fuel switch the Sutherland Generating Station (Sutherland) Combustion Turbines (CTs) from oil to natural gas operations;
- Consider all supply-side options and only commit to resources that are in IPL's and IPL's customers' best interest.

DSM Activities

IPL's current DSM programs have been aggressively pursued and are continuing to save customers' kilowatts (KW) and kilowatt-hours (KWh), and IPL will continue to analyze potential demand and energy savings from future DSM activities. DSM activity is reported annually in all regulatory jurisdictions in which IPL serves retail customers and these filings on DSM programs are expected to continue.

Supply-Side Activities

IPL is committed to meeting the demands of its customers and plans to meet its resource needs consistent with the regulations of the governing jurisdictions. In Section 5 of IPL's 2014 IRP, the types of resources required to meet IPL's customer needs are identified. Without resource additions beyond MGS, IPL projections show a short-term capacity shortfall in 2015 and 2016, and then no capacity shortfall until 2023, with a significant capacity shortfall beginning in 2025. The immediate incremental capacity and energy needs through 2019 will most likely be met with a combination of existing resources, MISO market energy, capacity purchases in 2015 and 2016 (as necessary), and the installation of MGS in 2017.

In the 2012 Baseload Diversification Study and the 2014 IRP, IPL considered the ongoing viability of its older peaking and intermediate steam units. As discussed in Section 6 of this IRP, IPL plans to retire several units which is subject to approval from MISO through the Attachment Y process.

[TRADE SECRET DATA BEGINS

At its , IPL will install

[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]

TRADE SECRET DATA ENDS] IPL's Tier 2 Kapp 2 unit will be converted from coal to natural gas operation in the spring of 2015. Long term plans for these units continue to

[TRADE SECRET DATA BEGINS

be evaluated

TRADE SECRET DATA ENDS]

At its Tier 1 coal-fired units Neal 3 and 4, Louisa, Ottumwa, and Lansing 4, IPL will install emission controls for MATS compliance, and IPL will pursue capacity and efficiency upgrades.

At its Marshalltown, Iowa facilities, IPL will switch fuel for its Sutherland CTs from oil to natural gas, and will complete construction and installation of the approximate 650 MW MGS combined cycle facility in 2017.

IPL customers' demands will be met and customers' rates will be kept as low as reasonably possible. This Five-Year Action Plan will continually be reviewed and revised, as new information with respect to IPL's resource needs becomes available. IPL's resource planning process is continuously iterative and Electric Integrated Resource Plans are regularly filed in Minnesota and Iowa. In the interim, all resource options will continue to be considered and evaluated.

Renewable Resource Activities

IPL is committed to meeting the renewable policy goals of the states in which it serves. IPL continues to consider renewable energy, especially wind energy, a viable option for future resource needs. Currently, IPL purchases capacity and energy from approximately 250 MW (nameplate capacity) of wind turbines. In 2009, IPL added 200 MW of wind resource with its addition of Whispering Willow Wind Farm-East. With these existing resources, IPL as a whole is projecting to be in surplus relative to Minnesota and Iowa renewable energy requirements, as they are currently written, over the next five years. Further, expansion plans for the 2014 IRP include significant wind additions, such that new and existing wind constitutes approximately 25% of the energy portfolio. Therefore, IPL is well-positioned to meet both its Iowa and Minnesota renewable energy requirements through the study period (2029).

IPL estimates Minnesota Solar Energy Standard requirements of roughly 8 MW by 2020. This requirement is represented in the IRP EGEAS modeling as a minimum forced 10 MW addition, with the modeling able to select additional solar if economic. The EGEAS output results did not select any more than the minimum amount required.

Environmental Considerations

As shown in the charts below, IPL's projected annual CO_2 output (tons) in its No Carbon and Minnesota Midpoint 2017 Carbon Reference Cases noticeably decline through the 15 year study period, despite IPL's energy growth.

Figure 3: No Carbon Reference Case CO2 Emissions and Rate

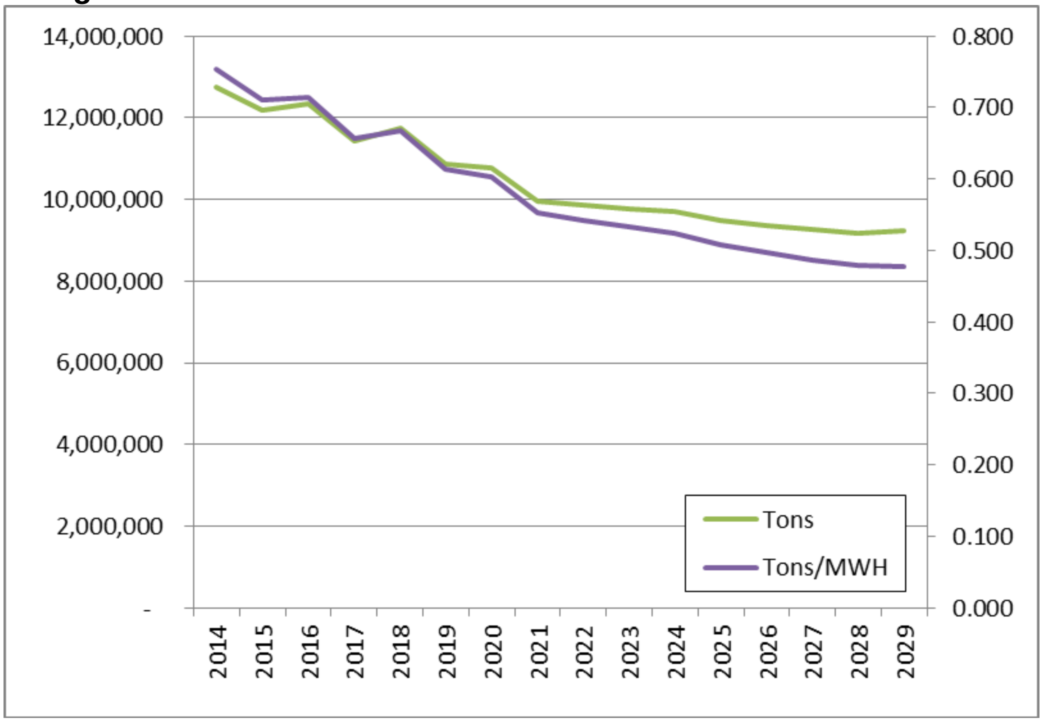
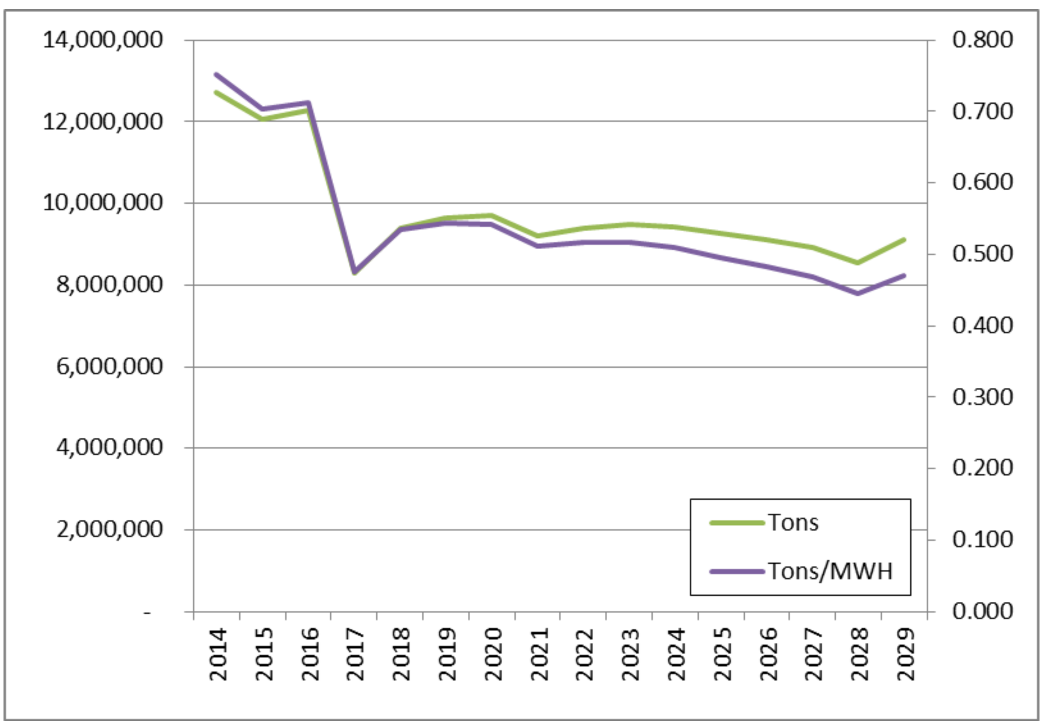


Figure 4: Minnesota Midpoint 2017 Carbon Reference Case CO2 Emissions and Rate



<u>Impacts on Electric Rates and Bills</u>

IPL develops IRPs based on the lowest cumulative present worth of revenue requirements, given regulatory and other constraints. This ensures an optimum plan and reasonable rates for customers. The EGEAS results indicate that IPL's total costs (fuel, operations & maintenance, and new capital fixed charges) per kWh over the study period will increase nominally at an average rate of about:

- 4.5 percent per year for the No Carbon scenario; and
- 5.8 percent per year for the Minnesota Midpoint 2017 Carbon scenario.

Assuming an inflation rate of approximately 2 percent per year over that same time period, the change in real terms is approximately:

- 2.4 percent per year for the No Carbon scenario; and
- 3.7 percent per year for the Minnesota Midpoint 2017 Carbon scenario.

As a customer-focused electricity manufacturer, IPL will continue to provide safe, efficient and cost-competitive electric service to its customers.

IPL continues to monitor the political and legislative climate to attempt to anticipate renewable and emissions regulatory standards that may be implemented. IPL intends to comply with all applicable standards, and exceed those standards when doing so is viable, economical, and appropriate.

Conclusion

IPL believes this IRP provides a comprehensive generation expansion and resource plan that appropriately balances all considerations and best serves its customers of Minnesota and Iowa.

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

TABLE OF CONTENTS

INTRODUCTION

This is the 2014 Electric Integrated Resource Plan of Interstate Power and Light Company (IPL or Company), a regulated utility company of Alliant Energy Corporation (Alliant Energy). IPL's 2014 Electric Integrated Resource Plan (Resource Plan or IRP) is being filed pursuant to Chapter 7843 of the Minnesota Public Utilities Commission (Commission) rules as an update to IPL's 2010 Resource Plan and IPL's 2012 Baseload Diversification Study. This IRP is also being filed with the State of Iowa.

This section provides an Overview of the IPL System and IRP Development, discusses Future Industry Considerations, and explains Minnesota and Iowa regulatory requirements that are reflected in the IRP.

1.0 The IPL System

IPL is a public utility engaged principally in the generation and distribution of electricity and the distribution and transportation of natural gas in selective markets in southern Minnesota and in Iowa. IPL serves more than 525,000 electric customers and more than 230,000 natural gas customers in over 100 counties in Iowa and Minnesota. IPL's electric customers currently have an internal peak demand of 3,121 MW, which is projected to grow 430 MW over the next 15 years. After reductions for demand response and coincident peak with the Midcontinent Independent System Operator, Inc. (MISO), IPL's resource adequacy obligations are 2,896 Zonal Resource Credits (ZRCs), which is projected to grow 399 ZRCs over the next 15 years. A ZRC is equal to one MW of unforced capacity (UCAP) from a planning resource for a given zone during a specific planning year, as described in the requirements set forth in Module E of the MISO Tariff.

Of IPL's electric retail customers, Iowa accounts for approximately 92 percent, and Minnesota approximately eight percent. IPL's Illinois retail load was sold in February 2007, but is still being served today by IPL as a wholesale load to Jo-Carroll Energy. The forecast used in this 2014 IRP assumes continued service to a large wholesale customer.

IPL's service territory encompasses approximately 52,000 square miles, including over 22,000 miles of electric distribution line and over 5,000 miles of natural-gas transmission and distribution main. IPL currently owns generating facilities located in both Iowa and Minnesota. These IPL-owned units produce approximately 2,495 ZRCs towards MISO resource adequacy requirements. IPL's portfolio includes base load plants which operate year round and are fueled with coal. IPL's portfolio also includes intermediate or combined cycle units, such as the Emery Generating Station, which provide load following capability and are primarily fueled with natural gas. Combustion turbines and diesel generators at various locations throughout IPL's system provide supplemental energy at points throughout the year when demand is highest. IPL installed in late 2009 a 200 MW wind farm, Whispering Willow Wind Farm - East, in Franklin

County, Iowa, which IPL owns and operates. Further, IPL is installing the approximate 650 MW Marshalltown Generation Station combined cycle facility with a spring 2017 in-service date. In addition to owned generation, IPL has purchased power contracts for approximately 250 MW from various wind resources as well as for approximately 400 MW from the Duane Arnold Energy Center nuclear plant. IPL delivers the energy and exceptional service that its customers and communities count on – safely, efficiently and responsibly.

As previously noted, IPL has entered into an agreement with SMEC for the transfer of all IPL's Minnesota electric distribution assets and operations to SMEC. IPL will retain ownership of all its generation assets and SMEC and IPL will enter into an agreement with a term of 10 years under which IPL will provide all electric power needed to serve customers in the area in Minnesota to be transferred from IPL to SMEC. As a result, IPL's generation and load in Minnesota will remain essentially unchanged by a transfer to SMEC.

1.1 Overview of Plan Development

The process used in developing this plan began with the system load forecast. This forecast includes the needs of all firm IPL customers. IPL's firm load forecast at the time of MISO's summer peak, plus a reserve requirement, is matched against existing capacity to determine IPL's preliminary resource needs. By using the Electric Generation Expansion Analysis System (EGEAS) computer model, all combinations of existing resources and modeled future resource alternatives are considered when determining the optimal expansion plan. Renewable alternatives, Demand-Side Management (DSM) programs and conventional supply-side units are all considered in the resource planning process. The objective function within EGEAS is to minimize the cumulative present worth of revenue requirements for the 15-year planning period plus a 35-year extension period, while maintaining the MISO coincident peak planning reserve margin (PRM_{ucap}) of 7.3 percent in each year. However, system reliability and financial risks must also be considered. The ultimate goal is to minimize cost, maximize reliability and minimize risk. Given reasonable assumptions and after careful consideration of costs, reliability and risks, a reference case is constructed.

Once a reference case was determined, IPL developed additional scenarios and sensitivities by changing various input assumptions. Some of the scenarios and sensitivities are based on are regulatory requirements, while IPL creates others by varying key input assumptions to provide supplemental insight. Examples of sensitivities include changes to:

- Load forecast
- Market economy energy availability
- Fuel costs
- Capital costs

For this 2014 IRP, IPL performed the sensitivity analysis under three sets of Carbon monetization scenarios: (i) No Carbon; (ii) Wood Mackenzie 2023

Carbon; and (iii) Minnesota Midpoint 2017 Carbon. As a result, there is no longer one base case. Instead, there are three sets of carbon scenarios with sensitivities for each scenario.

1.2 Future Industry Considerations

IPL believes that it is important to consider changes and potential future changes affecting the electric utility industry before making resource decisions, such as those reflected in this IRP. Currently, one of the biggest issues affecting resource planning is the uncertainty surrounding potential greenhouse gas regulation. As noted previously, IPL considers these impacts by modeling three different sets of Carbon scenarios: (i) No Carbon; (ii) Wood Mackenzie 2023 Carbon; and (iii) Minnesota Midpoint 2017 Carbon. As a result, there is no longer one base case. Instead there are three sets of carbon scenarios with sensitivities for each scenario. These three CO_2 cost scenarios are further described in Section 6.3.3. Further, as one-off sensitivity analysis, IPL varies the Minnesota Carbon value to a Low and High Range.

Potential future greenhouse gas regulation introduces risks that must be considered before a utility commits to a resource planning decision. When the outcome of greenhouse gas regulation is determined the impacts on resource planning will become clearer. In the meantime however, the result for resource planning is that while future needs can be projected and considered, investing in future resources can only be done when the risk is supported by a reasonable expectation of a fair and timely return on investment.

1.3 Iowa Requirements

The following are the Iowa Utilities Board (IUB) requirements that affected the IRP

1.3.1 Nuclear Purchase

On August 7, 2012, IPL filed an amendment in IUB re-organization Docket No. SPU-2005-0015 to continue purchasing capacity and energy from NextEra's Duane Arnold Energy Center (DAEC) for 2014 through 2025. The IUB issued an Order on January 31, 2013, allowing IPL to amend the contract and continue purchases from the DAEC. IPL also filed the information pertaining to DAEC in Docket No. E001/RP-08-673 on August 28, 2012. IPL's 2014 IRP likewise includes the continued purchase from DAEC.

1.3.2 Marshalltown Generating Station (MGS)

On November 14, 2012, IPL filed the necessary applications with the IUB that would allow IPL to build the MGS, an approximate 650 MW natural gas-fired, combined cycle-generating unit. Specifically, IPL submitted with the IUB an application for a generating facility certificate to construct and the MGS in Marshalltown, Marshall County, Iowa. Also on November 14, 2012, IPL filed a request for advance ratemaking principles that would apply to the MGS. On November 8, 2013, the IUB issued an Order in Docket Nos. GCU-2012-01 and

RPU-2012-003 granting IPL's application and awarding advance ratemaking principles. IPL's 2014 IRP assumes the 2017 installation of MGS as a committed resource.

1.4 Commission Requirements

The following are the Commission requirements that have affected the IRP.

1.4.1 Requirements as a Result of 2010 Resource Plan

On March 2, 2012, in Docket No. E001/RP-08-673, the Commission issued an "Order Approving Resource Plan With Modifications, Requiring Baseload Diversification Study And Additional Filings, And Setting Date For Next Resource Plan" for IPL's 2010 Resource Plan. The Commission accepted IPL's 2010 Resource Plan (for 2010-2025), while expressing several concerns. Specific concerns of the Commission identified in that Order are addressed below. The references listed below correspond to the specific points in the Order.

1. *The Commission approves Interstate Power and Light's Integrated Resource Plan subject to the conditions below. Approving this resource plan does not extend to particular generation projects that are currently under review in other proceedings or will be subject to review under future proceedings. Instead, it is a general finding that the plans filed by Interstate Power and Light appear to be reasonable.*

   No specific IPL action is required.

2. *IPL shall consider wind additions averaging about 100 MW annually, provided that:*
   a. *The Company shall use a bidding process; and*
   b. *the bidding process results in a reasonable price.*

   During 2013, IPL conducted a Request for Proposals (RFP) effort seeking to explore purchase opportunities for up to 100MW of additional wind energy on a long-term basis (10+ years). The RFP was broadcast via industry publications and trade associations to assure a broad distribution. Ultimately, IPL received 38 distinct proposals with terms ranging from 5-25 years in duration and in sizes ranging from 40-100MW. Eight of the proposals were from existing wind farms, while the remainders were new build proposals.

   IPL performed initial economic screening of cost based on a net present valuation of the proposals and determined a shortlist of potential projects. This screening also eliminated certain projects that were deemed non-viable (ie, located in PJM, etc.) IPL then assessed the expected MISO Locational Marginal Pricing (LMPs) for the location of each of the proposed projects to identify the cost impact on IPL's customers, comparing Power Purchase Agreement (PPA) cost with expected MISO revenue.

In all cases, the cost of the PPA would be greater than expected MISO revenue driven by the present transmission limitations and resulting congestion cost, particularly over the next 5 years. As a result of this assessment, IPL determined that none of these proposals would result in a reasonable price, and IPL closed out the project.

3. *IPL shall meet with the Department to discuss forecasting issues.*

   As discussed in IPL's 2012 Baseload Diversification Study, Attachment B, filed in Docket No. E001/RP-08-673, IPL has worked with the Department on forecasting issues. The forecasting methodology discussion in Section 2 of this 2014 IRP provides additional information.

4. *IPL shall include in its base case a CO_2 cost at the mid-point of the Commission-approved range for subsequent resource plans.*

   For this 2014 IRP, IPL performed the sensitivity analysis under three sets of Carbon monetization scenarios: (i) No Carbon; (ii) Wood Mackenzie 2023 Carbon; and (iii) Minnesota Midpoint 2017 Carbon. In contrast, previous resource plans evaluated carbon monetization as a one-off analysis, not necessarily in the base case. As a result, there is no longer one base case. Instead there are three sets of carbon scenarios with sensitivities for each scenario. Section 6.3.3 of this IRP provides further discussion on carbon modeling.

5. *The Commission approves IPL's proposed 1.4 percent DSM energy savings target for resource planning purposes.*

   No specific IPL action is required.

6. *The Commission finds that IPL's proposed level of long-term market reliance (long-term defined as years 2015 – 2025) is unreasonable for planning purposes.*

   For this 2014 IRP, IPL has significantly reduced long-term market availability in the modeling. The lower priced Off Peak market energy is only available in the model during off peak hours, and market energy as a whole is limited to 5 percent of total annual energy following the installation of MGS in 2017. In contrast, the 2010 IRP allowed roughly 14-17 percent.

7. *IPL shall consider a renewal of the power purchase agreement with DAEC, provided that the price is reasonable.*

   As noted previously, IPL has amended its PPA and extended its energy and capacity purchases from the DAEC. The 2014 IRP modeling further assumes the purchase continues past the expiration of the DAEC PPA (in 2025) and through the license term of the unit (through 2033). IPL presumes that as long as DAEC continues to run, IPL is a potential buyer. However, pricing is of particular concern and will need to be negotiated. IPL anticipates that, similar to the efforts taken in previous years which resulted in a Request for Proposals, it will undertake similar bidding processes to ensure competitive value for customers before the expiration of this amended PPA.

8. *Within nine months of the date of this Order, IPL shall file a baseload diversification study. Included with the baseload diversification study, IPL shall also:*
   a. *specify the costs of environmental controls on each of IPL's Tier 1 units, the environmental controls to be used, the in-service dates, and the regulations with which they are intended to comply;*
   b. *justify its assumptions regarding heat rates and availability over time at its generating units, with a specific emphasis on the operational performance of its Tier 2 coal units; and*
   c. *run contingencies for coal of +30 percent, +20 percent, +10 percent, and -10 percent of their base assumptions, and contingencies for a broad range of natural gas prices.*

   IPL filed its 2012 Baseload Diversification Study with the Commission on December 3, 2012, in Docket No. E001/RP-08-673. On May 13, 2013, the Commission issued an Order finding that IPL complied with the requirement of the Commission's March 2, 2012 order regarding the Baseload Diversification Study.

9. *Within nine months of the date of this Order, IPL shall make a compliance filing regarding the Company's plans for their Tier 2 units that justifies IPL's decision and incorporates a revised analysis of IPL's future resource mix. IPL shall include a flood risk assessment of the Company's Prairie Creek units provided IPL expects to continue their operation, in their Tier 2 unit analysis.*

   The 2012 Baseload Diversification Study filed with the Commission on December 3, 2012, in Docket No. E001/RP-08-673 included analysis and discussion of plans for the Tier 2 units, a revised analysis of IPL's future resource mix, and a flood risk assessment of the Prairie Creek units. On May 13, 2013, the Commission released an Order finding that IPL complied with the requirement of the Commission's March 2, 2012 Order.

10. *IPL shall file a notice of changed circumstances regarding the status of its DAEC power purchase agreement within 30 days after a decision is reached, but no later than the time of its next resource plan filing. IPL shall also file with the Commission, as they become available: information concerning responses to power purchase requests for proposals; the outcome of power purchase request for proposals; and any related Iowa filings.*

    These filings were made in Docket No. E-001/RP-08-673.

11. *In its next resource plan IPL shall:*

    a. *justify its assumptions regarding heat rates and availability over time at its generating units, with a specific emphasis on the operational performance of its Tier 2 coal units;*

       Heat Rate and Availability over time assumptions are addressed in section 6.10.

    b. *provide detailed information regarding environmental control proposals, their costs, and the regulations for which they are needed to comply;*

       Section 6.3.9 (and subsections), describe the assumptions made for existing IPL units. Sections 6.3.9.1 through 6.3.9.4 describe Tier 1 and Tier 2 environmental controls, the in-service dates, and the regulations for which they are intended to comply. Appendix 6D details the projected cost and operating parameters of the Tier 1 and Tier 2 units.

    c. *run contingencies for coal of +30 percent, +20 percent, +10 percent, and -10 percent of their base assumptions, and contingencies for a broad range of natural gas prices.*

       These broad coal and natural gas price scenarios are included in this IRP as discussed in sections 6.5g through 6.5i.

    d. *incorporate its demand response study and include the potential for demand response capacity savings in Minnesota within its scenario analyses.*

       Minnesota Demand Response and modeling is addressed in Appendix 6O, and Section 6.5v.

12. *IPL shall make its next resource plan filing on or before November 1, 2013.*

    On May 13, 2013, in Docket No. E001/RP-08-673, the Commission issued an Order finding that IPL complied with the requirement of the Commission's March 2, 2012, Order regarding the Baseload Diversification Study and required IPL to file an updated resource plan in the first quarter of 2014.

13. *This Order shall become effective immediately.*

    No specific IPL action is required.

<u>1.4.2 Orders and Requirements as a Result of Baseload Diversification Study</u>

On May 13, 2013, in Docket No. E001/RP-08-673, the Commission issued an "Order Finding Baseload Diversification Study In Compliance With 2012 Resource Plan Order, Setting Date For Next Resource Plan, And Setting Further Requirements." Specific concerns of the Commission identified in that Order are addressed below. Alphanumeric references listed below correspond to the specific point in that Order.

1. *The Commission finds that Interstate Power and Light Company has complied with the requirement of the Commission's March 2, 2012 Order Approving Resource Plan With Modifications, Requiring Baseload Diversification Study and Additional Filings, and Setting Date for Next Resource Plan to file a Baseload Diversification Study.*

   No specific IPL action is required.

2. *IPL shall make its next resource plan filing in the first quarter of 2014, after the Company has received a decision from the Iowa Utilities Board regarding its Marshalltown Generating Station.*

   This 2014 IRP is filed to meet this Order point.

3. *IPL shall work with the Department to inform its analysis for its next resource plan, using the guidance set forth herein.*

   The guidance in the Order directed IPL to consider the following:

   - *Use of consistent energy and demand forecasts and load shapes;*

     Modeling inputs for previous resource plans included a one-year historical load shape file, and projected annual demands based on firm demand. This resulted in some confusion regarding apparent differences in load factors.

     For this resource plan, IPL has modeled firm demand reductions as Demand-Side Resources. This facilitates improved alignment between the modeled load factor and the load shape file. See section 6.3.2 for additional information.

   - *Limiting the amount of energy it draws from the spot market each year to five, and at most ten percent;*

     For this 2014 IRP, IPL has significantly reduced long-term market availability in the modeling. The lower priced Off Peak market energy is only available in the model during off peak hours, and market energy as a whole is limited to 5 percent of total annual energy following the installation of MGS in 2017. In contrast, the 2010 IRP allowed roughly 14-17 percent in all years.

   - *Use of the midpoint of the Commission-approved CO2 regulatory costs in the Company's base case;*

     For this 2014 IRP, IPL performed the sensitivity analysis under three sets of Carbon monetization scenarios: (i) No Carbon; (ii) Wood Mackenzie 2023 Carbon; and (iii) Minnesota Midpoint 2017 Carbon. In contrast, previous resource plans evaluated carbon monetization as a one-off analysis, not necessarily in the base case. As a result, there is no longer one base case. Instead, there are three sets of carbon scenarios with sensitivities for each scenario. Please see section 6.3.3 of this IRP for further discussion on carbon modeling.

- *Use of the Commission-approved externality values in the Company's base case;*

  All base and sensitivity runs under the Minnesota Midpoint 2017 Carbon scenario include externalities at the midpoint of the Commission-approved low and high range. IPL also included low and high externality value cases as sensitivities. See section 6.3.3 for the externality discussion and sections 6.5o and 6.5p for the results of low and high value variations.

- *Evaluation of the impact of lower and higher wind prices on the Company's expansion plan; and*

  IPL included wind price variations of +/- $10/MWH and +/- $20/MWH. See section 6.3.7 for discussion of wind prices, and sections 6.5k and 6.5l for the results of low and high value variations. Wind pricing in this IRP was based on new facility data per the 2013 Black & Veatch Power Station Characterization Study. See Appendix 5C for breakdown of costs and operating parameters. IPL estimates these costs at roughly $45/MWH on a levelized basis for a 2013 installation.

- *Use of a forecast that includes data points through at least September 2013.*

  For this 2014 IRP, IPL is using a load forecast dated October 31, 2013. For consistency, this forecast was created to meet the November 1, 2013, MISO resource adequacy filing deadline, as well as the IRP filing requirement. The forecast was developed from data points through the end of August 2013. This was the most recent data available which IPL could, verify the peak data, develop the forecast, and incorporate into MISO's new and changing filing requirements in time for the November 1 deadline. Since IPL's peak for 2013 was set on July 17th, including September data points would not add significant material value. See section 2 for additional information on forecast development.

4. *This Order shall become effective immediately.*

   No specific IPL action is required.

<u>1.4.3 Other Orders and Notices</u>

On August 5, 2013, in Docket No. E001/RP-08-673 (and others), the Commission issued a "Notice Of Information In Future Resource Plan Filings" regarding "Information In Future Resource Plan Filings." Specific concerns of the Commission outlined in that Notice are provided below, and IPL's responses immediately follow.

- *Please take notice that the Commission expects utilities to include in their resource plans filed after August 1, 2013 an explanation how the resource plan helps the utility achieve the greenhouse gas reduction goals, renewable energy standard, and solar energy standard as listed in the above-referenced legislation. Parties should also be prepared to discuss the matter in comments.*

Greenhouse Gas Reduction Goals

The Minnesota greenhouse gas reductions goals from Minnesota Statute 216H.02 are sector-wide reductions of 15 percent below 2005 levels by 2015, and 30 percent below 2005 levels by 2025. IPL's 2014 IRP supports these goals with declining system carbon dioxide emissions and emission rates as discussed in Section 8.3. IPL has already retired or fuel switched several coal-fired units (for example: Sixth Street, Dubuque and Sutherland). The 2014 IRP includes significant wind additions after the Five Year Plan, [TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]

Renewable Energy Standard

IPL's expansion plans call for a significant amount of new wind after 2018, such that by the end of the study period wind could provide approximately 25% of all energy needs.

Solar Energy Standard

The recently passed Minnesota Solar Energy Standard (SES) requires IPL to generate or procure sufficient solar energy to serve 1.5 percent of its Minnesota retail load, with at least 10 percent of the 1.5 percent to be served from PV with a nameplate of 20 kilowatts or less. This requirement is separate from the Minnesota 25 percent Renewable Energy Standard previously discussed. IPL estimates solar installations of roughly 8 MW to meet compliance. To capture the impact of the SES in the expansion plan of the 2014 IRP IPL set EGEAS modeling constraints such that a minimum of 10 MW of solar was selected by 2020.

- *In addition, utilities should consider adding to their initial resource plan filings the supplemental information listed at page 4 of the Commission's May 10, 2013 Order regarding its completeness review of MP's resource plan in Docket E015/RP-13-53.*

The supplemental information referred to is listed below:

1. *How the addition of SO2 allowance prices would have impacted its base case and preferred plan;*

   IPL performed wide sensitivities on SO_2 allowance prices from very low \$0/ton to \$1,000/ton and \$2,000/ton. Results of these sensitivities are discussed in section 6.5s. There was no change to the expansion plan, and present value impacts were relatively small in comparison to other sensitivities. This is a result of movement in IPL's coal fleet to emission control additions, gas conversions, and retirements. Wood Mackenzie's projections assume very low trading SO_2 prices for similar reasons.

2. *How the use of unforced capacity would have impacted its base case and preferred plan;*

   IPL's 2014 IRP uses unforced capacity (UCAP), as opposed to Minnesota Power's resource plan which IPL understands used Installed Capacity (ICAP). Therefore, there is no impact to IPL's expansion plans, since IPL already uses unforced capacity.

3. *How the use of Commission-approved CO2 values from its November 2, 2012 Order affect its base case and preferred plan;*

   See section 6.5, and subsections, for a discussion of CO_2 cost and expansion plan impacts between IPL's three carbon scenarios. IPL's expansion plans for the various carbon scenarios and sensitivity cases are relatively stable, with additions for a significant amount of wind throughout the study period, and gas additions later in the study period. However, carbon monetization prices do have a significant impact on present value cost.

4. *How MP has considered water consumption issues and potential effects on aquatic life from water intake and discharge in its resource plan, both qualitatively and quantitatively.*

   Please see section 7.6.4 for this discussion.

5. *How MP has taken into account possible effects of drought and high water temperature on generating plant availability in its modeling, including the results of modeling the range of these possible effects.*

   Please see section 6.11 for this discussion.

6. *How MP has considered demand side management (DSM) programs in its resource plan, and the pros and cons of DSM being considered a reduction in load versus a resource to be chosen, including modeling a range of assumptions.*

   Please see section 6.5v for this discussion.

- *Staff also recommends that utilities consider convening a stakeholder meeting prior to filing their initial IRPs to answer questions about assumptions used in the filing, for the purpose of responding to questions which could enhance parties' understanding of the filing and reducing the number of information requests parties may need to file.*

  A stakeholder conference call meeting was held on March 18, 2014.

1.4.4 Requested Firm Gas Discussion Requested in Fourth Quarter MISO/Minnesota Stakeholder Meeting

At the December 6, 2013, Fourth Quarter MISO/Minnesota Stakeholder Meeting, the Department of Commerce asked that utilities address in their IRPs how firm gas is purchased when needed. Section 6.9 provides this discussion.

LOAD FORECAST

2.0 Overview of the Base Load Forecast

The IPL load forecast is used as the base forecast in the EGEAS model. The elements of the IPL load forecast are described in the following subsections:

- Section 2.1 – Base Forecast
- Section 2.2 – IPL Energy forecasts
- Section 2.3 – IPL Demand forecast
- Section 2.4 –Sensitivity and Scenarios
- Section 2.5 – Discussion of Demand Side Management (DSM)

The load forecast has two main components: the energy forecast and the demand forecast. The assumptions and methodologies for calculating the energy and demand forecasts are included in sections 2.2 and 2.3. To illustrate the sensitivity of the IRP to changes in the load forecast, confidence intervals, as well as high and low scenarios are found in section 2.4. Section 2.5 discusses how demand side resources are handled within the load forecast.

2.1 Base Forecast

Table 2.1.1 summarizes IPL's annual energy and internal peak demand forecast in the base forecast.

Table 2.1.1
IPL Base Forecast: Energy and Internal Peak Demand

Year	Energy (GWH)	Internal Peak Demand (MW)
2014	16,928	3,121.3
2015	17,115	3,151.7
2016	17,274	3,179.1
2017	17,428	3,205.7
2018	17,585	3,232.8
2019	17,728	3,257.6
2020	17,884	3,284.6
2021	18,041	3,311.8
2022	18,200	3,339.3
2023	18,360	3,368.8
2024	18,522	3,398.5
2025	18,685	3,428.4
2026	18,850	3,458.6
2027	19,016	3,489.1
2028	19,184	3,519.9
2029	19,353	3,550.9

The translation from the Internal Peak Demand forecast to the EGEAS net load variable is found in Chapter 6.

2.2 IPL Energy Forecast

2.2.1 Methods

The calculation of IPL's energy forecast starts with a trended forecast of the number of meters. Forecasted meters are then multiplied by the results from a regression model of use per meter. The resulting forecasted values are then added to specific large customer forecasts, compared with recent historical class level sales, and adjusted for external factors. Forecasts of IPL's smaller classes are also added. Finally, estimated transmission and distribution losses are applied to arrive at the energy forecast. For the longer term forecast (from 2019-2029) IPL applied the growth rate from the regression model.

2.2.2 Data

Sources of information for key factors used in this process include:

- Sales and meters (IPL uses 10 years of calendar month data).
- Weather is measured using Heating Degree Days (HDD) and Cooling Degree Days (CDD) and matched to the sales. Normal is defined as the 20-year rolling average using the average of the daily high and low temperature with a base of 65 degrees. Weather is reported from the Cedar Rapids Airport.
- Economic data comes from a third party vendor, IHS Global Insight, unless otherwise stated.

2.3 IPL Demand Forecast

2.3.1 Definitions

Internal Peak Demand is defined as the highest observed load. For forecasting purposes, IPL adds any interruptions or Direct Load Control (DLC) to the Internal Peak Demand, to calculate the **Theoretical Demand**.

2.3.2 Method

To forecast demand, IPL uses Theoretical Demand, the highest observed load plus the estimated interrupted and DLC called during the peak time. Next, IPL reduces historical system load data by the load attributed to the large customers which are forecasted individually. The remaining customers are forecasted using a consensus of three different regression models. The three models represent annual peak, monthly peaks, and summer seasons. The annual and summer seasonal models are averaged to arrive at an annual peak forecast. The annual forecast is then calendarized based on the monthly model. The individually forecasted customer peaks are added to the modeled results to arrive at the demand forecast. Finally the demand forecast is compared with the corresponding energy model for reasonability. In the current plan, due to divergent growth rates between demand and energy, the growth rate of the demand forecast was adjusted to match the growth rate from the energy forecast.

2.3.3 Data

All three regression models use:

- Ten years of peak demand and weather data;
- Theoretical Demand less large customer demand (Large Customer demand is forecasted independently from the regression models); and
- Personal Income from IHS Global Insight.

Individual models use, respectively:

- Annual model uses:
  - highest observation of load per year; and
  - high temperature on the peak day.
- Monthly model uses:
  - highest observation of load per month; and
  - heating degree days and cooling degree days.
- Seasonal model uses:
  - weekdays and non-holidays in June through September; and
  - peak day high temperature, prior day temperature, overnight low, and the dew point.

2.4 Sensitivity and Scenarios

2.4.1 Sensitivity

To estimate the sensitivity of the load forecast, IPL constructed annualized confidence intervals for the energy and demand forecasts.

2.4.1.1 Energy Confidence Interval

The confidence interval for the energy forecast utilizes a rolling 12-month annual error. The forecast error was determined using the 95% critical value on the standard deviation of the rolling annual errors. The confidence interval is presented below in Table 2.4.1.1. While the large industrial, wholesale, and small classes, like lighting, municipal pumping, and interdepartmental, are not statistically modeled, IPL applies the confidence interval as a percentage to the annual sales.

Table 2.4.1.1
95% Confidence Intervals IPL Energy Models (GWH)

Year	Lower Confidence Interval	Base Energy	Upper Confidence Interval
2014	16,678	16,928	17,178
2015	16,862	17,115	17,368
2016	17,019	17,274	17,529
2017	17,170	17,428	17,686
2018	17,325	17,585	17,845
2019	17,466	17,728	17,990
2020	17,620	17,884	18,148
2021	17,774	18,041	18,308
2022	17,931	18,200	18,469
2023	18,089	18,360	18,631
2024	18,248	18,522	18,796
2025	18,409	18,685	18,961
2026	18,571	18,850	19,129
2027	18,735	19,016	19,297
2028	18,900	19,184	19,468
2029	19,067	19,353	19,639

2.4.1.2 Demand Confidence Interval

The confidence interval for the demand forecast is shown below using the seasonal model which contains the greatest number of peak observations. To illustrate the forecast range stemming from historical variation from the model, the 95% confidence interval for the demand forecast is listed below.

Table 2.4.1.2
95% Confidence Interval
Internal Peak Demand (MW)

Year	Lower Confidence Interval	IPL (MW)	Upper Confidence Interval
2014	2,943.4	3,121.3	3,299.2
2015	2,972.1	3,151.7	3,331.3
2016	2,997.9	3,179.1	3,360.3
2017	3,023.0	3,205.7	3,388.4
2018	3,048.5	3,232.8	3,417.1
2019	3,071.9	3,257.6	3,443.3
2020	3,097.4	3,284.6	3,471.8
2021	3,123.0	3,311.8	3,500.6
2022	3,149.0	3,339.3	3,529.6
2023	3,176.8	3,368.8	3,560.8
2024	3,204.8	3,398.5	3,592.2
2025	3,233.0	3,428.4	3,623.8
2026	3,261.5	3,458.6	3,655.7
2027	3,290.2	3,489.1	3,688.0
2028	3,319.3	3,519.9	3,720.5
2029	3,348.5	3,550.9	3,753.3

2.4.2 Scenarios

To indicate the sensitivity of the resource plan to higher or lower than planned growth, IPL estimated a high and low load forecast as noted in Tables 2.4.2.1 and 2.4.2.2. To estimate the loads for these scenarios, IPL increased or decreased the expected growth rate of the base forecast by 50 basis points. Historically, IPL specifically identified the economic variable as the driver. However, in the current IRP, IPL recognizes that load could vary due to several variables other than just traditional economics variables, such as changes in wholesale contracts, distributed generation installations, conservation actions, or changes in electric prices.

Table 2.4.2.1
Energy Scenarios (GWH)

Year	Low	Base	High
2014	16,928	16,928	16,928
2015	17,031	17,115	17,200
2016	17,103	17,274	17,445
2017	17,170	17,428	17,688
2018	17,239	17,585	17,936
2019	17,293	17,728	18,171
2020	17,359	17,884	18,422
2021	17,424	18,041	18,676
2022	17,491	18,200	18,934
2023	17,557	18,360	19,195
2024	17,624	18,522	19,461
2025	17,692	18,685	19,729
2026	17,759	18,850	20,002
2027	17,827	19,016	20,278
2028	17,895	19,184	20,558
2029	17,963	19,353	20,842

Table 2.4.2.2
Internal Peak Demand
Scenarios (MW)

Year	Low	Base	High
2014	3,121.3	3,121.3	3,121.3
2015	3,136.1	3,151.7	3,167.3
2016	3,147.6	3,179.1	3,210.6
2017	3,158.2	3,205.7	3,253.6
2018	3,169.1	3,232.8	3,297.3
2019	3,177.6	3,257.6	3,339.1
2020	3,188.1	3,284.6	3,383.5
2021	3,198.6	3,311.8	3,428.5
2022	3,209.1	3,339.3	3,474.1
2023	3,221.4	3,368.8	3,522.1
2024	3,233.7	3,398.5	3,570.7
2025	3,246.0	3,428.4	3,620.1
2026	3,258.4	3,458.6	3,670.1
2027	3,270.8	3,489.1	3,720.8
2028	3,283.3	3,519.9	3,772.2
2029	3,295.8	3,550.9	3,824.3

Discussion of DSM

IPL has an extensive history in DSM in both Minnesota and Iowa. Because of the consistent history and the relatively small size, IPL does not use DSM as a separate input to the forecast. The DSM programs have been included in sales history, lowering historical sales data used to develop the forecast models. Since the forecast assumes that the DSM programs will continue in the forecast period, the programs are included implicitly in the forecast. To provide an illustration of the amount of implicit DSM, IPL found the historical cumulative impacts from the prior five years of DSM savings. The cumulative impact totaled 992 GWH, of which the Minnesota portion is 40 GWH or 0.3% of forecasted energy. See Table 2.5.1 for calculations.

Table 2.5.1
Estimate of implicit DSM

Annual Impacts (GWH)			
Year	IA	MN	Total
2009	177	8	185
2010	165	3	168
2011	191	7	199
2012	206	14	219
2013	213	8	221
total	952	40	992

IPL's Minnesota future DSM programs, approved by the Commission in Docket No. E, G001/CIP-12-484, are explained further in Section 3. The cumulative and annual impacts are shown in Table 2.5.2 below.

Table 2.5.2
Total Cumulative and Annual MN DSM (GWH)

Year	Total Cumulative	Annual
2014	12	12
2015	24	12
2016	35	12
2017	47	12
2018	59	12
2019	70	12
2020	82	11
2021	93	11
2022	103	10
2023	112	9
2024	121	9
2025	130	9
2026	139	9
2027	147	9
2028	156	8
2029	157	2

IPL also has an approved Energy Efficiency Plan in Iowa. However, the approved plan covers the period 2014 through 2018. The data in Table 2.5.3 assumes that IPL's Iowa DSM program impacts for 2018 continue through 2029. The table below shows that the implicit estimate DSM, using the five year average, and the actual planned DSM are similar:

Table 2.5.3
Comparison of Implicit and Planned DSM

Year	Annual Impacts (GWH) IA*	MN	total	5 yr Cumulative (GWH) IA	MN	total	Implict	difference (implicit less planned)	Difference as a % of Energy
2009	177	8	185	NA	NA	NA			
2010	165	3	168	NA	NA	NA			
2011	191	7	199	NA	NA	NA			
2012	206	14	219	NA	NA	NA			
2013	213	8	221	952	40	992	992		
2014	178	12	190	953	44	997	992	(5)	0.0%
2015	161	12	173	950	52	1,002	992	(10)	-0.1%
2016	159	12	171	917	57	974	992	18	0.1%
2017	161	12	173	873	55	928	992	64	0.4%
2018	164	12	176	824	59	883	992	110	0.6%
2019	164	12	176	810	58	869	992	123	0.7%
2020	164	11	176	813	58	871	992	121	0.7%
2021	164	11	175	819	57	876	992	116	0.6%
2022	164	10	175	822	56	877	992	115	0.6%
2023	164	9	174	822	54	875	992	117	0.6%
2024	164	9	173	822	51	873	992	120	0.6%
2025	164	9	173	822	48	870	992	122	0.7%
2026	164	9	173	822	46	868	992	125	0.7%
2027	164	9	173	822	45	866	992	126	0.7%
2028	164	8	173	822	43	865	992	128	0.7%
2029	164	2	166	822	36	857	992	135	0.7%

* Based on assumed continuation of programs after 2018.

Appendix 2A

This appendix includes the following items:

- 2A.1 Model detail;
- 2A.2 Model changes; and
- 2A.3 Forecast as compared to prior filing.

2A.1 IPL Forecast Model Details

The files supporting the IPL forecast and descriptions of the files are found in the accompanying file-guide "IPL 2014 IRP Forecast Fileguide.xlsx"

2A.1.1. *IPL Residential Sales*

IPL forecasts monthly Residential sales based on the following econometric model of residential use per meter. Table 2A.1.1 shows the results of the IPL Residential model.

Table 2A.1.1
IPL Residential Sales Model Parameters

SUMMARY OUTPUT								
Regression Statistics								
Multiple R	0.965							
R Square	0.930							
Adjusted R Square	0.922							
Standard Error	0.045							
Observations	128							
ANOVA								
	df	*SS*	*MS*	*F*	*Significance F*			
Regression	14	3.079	0.220	107.896	0.000			
Residual	113	0.230	0.002					
Total	127	3.310						
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	0.6312	0.058	10.910	0.000	0.517	0.746	0.517	0.746
Feb	-0.1602	0.021	-7.646	0.000	-0.202	-0.119	-0.202	-0.119
Mar	-0.1149	0.030	-3.825	0.000	-0.174	-0.055	-0.174	-0.055
Apr	-0.1395	0.043	-3.277	0.001	-0.224	-0.055	-0.224	-0.055
May	-0.1429	0.051	-2.777	0.006	-0.245	-0.041	-0.245	-0.041
Jun	-0.0872	0.059	-1.484	0.140	-0.204	0.029	-0.204	0.029
Jul	0.1003	0.062	1.613	0.110	-0.023	0.223	-0.023	0.223
Aug	0.0723	0.060	1.210	0.229	-0.046	0.191	-0.046	0.191
Sep	-0.0631	0.054	-1.169	0.245	-0.170	0.044	-0.170	0.044
oct	-0.1517	0.043	-3.568	0.001	-0.236	-0.067	-0.236	-0.067
Nov	-0.1241	0.032	-3.906	0.000	-0.187	-0.061	-0.187	-0.061
Dec	-0.0684	0.021	-3.329	0.001	-0.109	-0.028	-0.109	-0.028
CR_HDD	0.0003	0.000	6.361	0.000	0.000	0.000	0.000	0.000
CR_CDD	0.0012	0.000	10.993	0.000	0.001	0.001	0.001	0.001
Cust_Def	0.0092	0.010	0.884	0.378	-0.011	0.030	-0.011	0.030

Where:

- CR_HDD: Cedar Rapids Heating Degree Days is the monthly sum of the positive differences between 65 and the daily average of the high and low temperature. This variable measures the impact of cold temperature on sales.
- CR_CDD: Cedar Rapids Cooling Degree Days is the monthly sum of the positive difference between the daily average of the high and low temperature and the base of 65. This variable measures the impact of warm temperatures on sales.
- Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, and Dec: monthly indicator variables that take the value of 1 for the representative month and 0 in other months to represents systematic fluctuation in sales.
- Cust_Def: customer definition is an indicator variable for January 2005 and beyond. This variable is necessary due to differences in how multiple meters at one location were counted.

2A.1.2 IPL Commercial Sales

IPL forecasts monthly Commercial sales based on the following econometric model of use per customer. Table 2A.1.2 shows the results of the IPL Commercial model.

Table 2A.1.2
IPL Commercial Sales Model Parameters

SUMMARY OUTPUT						
Regression Statistics						
Multiple R	0.896					
R Square	0.802					
Adjusted R Square	0.778					
Standard Error	0.168					
Observations	128					
ANOVA						
	df	*SS*	*MS*	*F*	*Significance F*	
Regression	14	12.950	0.925	32.717	0.000	
Residual	113	3.195	0.028			
Total	127	16.144				
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	3.516	0.215	16.320	0.000	3.089	3.943
Feb	-0.196	0.078	-2.518	0.013	-0.351	-0.042
Mar	-0.240	0.112	-2.143	0.034	-0.461	-0.018
Apr	-0.206	0.159	-1.299	0.197	-0.520	0.108
May	-0.168	0.192	-0.878	0.382	-0.548	0.211
Jun	0.090	0.219	0.410	0.682	-0.343	0.523
Jul	0.151	0.231	0.653	0.515	-0.307	0.610
Aug	0.254	0.222	1.141	0.256	-0.187	0.694
Sep	0.082	0.201	0.409	0.683	-0.316	0.480
oct	0.315	0.158	1.992	0.049	0.002	0.629
Nov	-0.015	0.118	-0.126	0.900	-0.249	0.220
Dec	0.019	0.076	0.244	0.808	-0.133	0.170
CR_HDD	0.000	0.000	1.911	0.058	0.000	0.001
CR_CDD	0.003	0.000	6.548	0.000	0.002	0.003
Cust_Def	0.247	0.039	6.391	0.000	0.170	0.323

Where:

- CR_HDD: Cedar Rapids Heating Degree Days is the monthly sum of the positive differences between 65 and the daily average of the high and low temperature. This variable measures the impact of cold temperature on sales.
- CR_CDD: Cedar Rapids Cooling Degree Days is the monthly sum of the positive difference between the daily average of the high and low temperature and the base of 65. This variable measures the impact of warm temperatures on sales.

- Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, and Dec: monthly indicator variables that take the value of 1 for the representative month and 0 in other months to represents systematic fluctuation in sales.
- Cust_Def: customer definition is an indicator variable for January 2005 and beyond. This variable is necessary due to a change in how multiple meters at one location were counted.

2A.1.3 IPL Industrial Sales

IPL forecasts monthly Industrial sales using the following econometric model of use per meter. Table 2A.1.3 shows the IPL Industrial model results.

Table 2A.1.3
IPL Industrial Sales Model Parameters

SUMMARY OUTPUT						
Regression Statistics						
Multiple R	0.822189662					
R Square	0.675995841					
Adjusted R Square	0.642186711					
Standard Error	11.43570582					
Observations	128					
ANOVA						
	df	*SS*	*MS*	*F*	*Significance F*	
Regression	12	31377.41983	2614.784986	19.99447629	7.13479E-23	
Residual	115	15039.16727	130.7753675			
Total	127	46416.58709				
	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	24.590	18.324	1.342	0.182	-11.706	60.885
Feb	0.553	4.876	0.114	0.910	-9.106	10.212
Mar	32.568	4.877	6.678	0.000	22.908	42.227
Apr	7.699	4.877	1.579	0.117	-1.961	17.360
May	27.040	4.877	5.545	0.000	17.380	36.700
Jun	34.719	4.877	7.119	0.000	25.059	44.379
Jul	25.235	4.877	5.175	0.000	15.576	34.895
Aug	39.173	4.877	8.032	0.000	29.512	48.834
Sep	18.375	4.997	3.677	0.000	8.478	28.273
oct	41.600	4.997	8.325	0.000	31.702	51.497
Nov	20.971	4.997	4.197	0.000	11.072	30.869
Dec	17.068	4.998	3.415	0.001	7.168	26.969
IPL_Income	4.007	0.528	7.591	0.000	2.961	5.052

Where:

- Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, and Dec: monthly indicator variables that take the value of 1 for the representative month and 0 in other months to represents systematic fluctuation in sales.
- IPL_Income: IA real per capita personal income. This measures economic activity either as customer's ability to consume or as a reflection of business's ability to compensate their owners and workers.

2A.1.4 *IPL Summer Peak*

Table 2A.1.4 shows the model results.

Table 2A.1.4
Summer Peak Parameters

REG PROC FOR NEW SUMMER PEAK FORECAST MODEL

The REG Procedure
Model: MODEL1
Dependent Variable: peak total

Number of Observations Read	1038
Number of Observations Used	920
Number of Observations with Missing Values	118

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	9	82434033	9159337	1181.47	<.0001
Error	910	7054788	7752.51405		
Corrected Total	919	89488821			

Root MSE	88.04836	R-Square	0.9212
Dependent Mean	2196.21693	Adj R-Sq	0.9204
Coeff Var	4.00909		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	1037.01498	57.42891	18.06	<.0001
Jul		1	65.47145	8.41092	7.78	<.0001
Aug		1	81.79093	8.22552	9.94	<.0001
Sep		1	8.51148	8.87848	0.96	0.3380
hot1	high-75	1	34.08078	0.87385	39.00	<.0001
Hot2	high-90	1	-7.32961	3.02420	-2.42	0.0156
hot3	low-60	1	8.14719	1.19719	6.81	<.0001
hot4	highdew-50	1	7.67145	0.67140	11.43	<.0001
prehigh		1	5.16945	0.53636	9.64	<.0001
I_RPI		1	0.00346	0.00039945	8.66	<.0001

Where:

- Jul, Aug, Sep are monthly indicators.
- Hot 1 is the Daily High temperature less 75 degrees. This captures the impact of warm weather on loads. For temperatures over 90, this is a positive value that is partially offset by the Hot2 variable.
- Hot2 is the Daily High temperature less 90 degrees. The coefficient is negative because the predicted increase in load from the Hot1 variable is partially offset when the temperature is over 90 degrees. This allows for a different reaction to temperature under extreme heat.
- Hot3 is the overnight low less 60 degrees. Warmer overnight temperatures lead to higher loads.

- Hot4 is the highest daily dew point less 50 degrees. This variable captures the fact that higher dew points, and therefore higher humidity, lead to higher cooling loads.
- Prehigh is the high temperature on the previous day. Repetitive high temperature days lead to higher loads.
- I_RPI is the Iowa Real Personal Income. Higher income leads to higher loads as consumers are more likely to use the comforts that electricity provides.

2A1.5 IPL Annual Peak

Table 2A.1.5 shows the model results.

Table 2A.1.5
Annual Peak Parameters

The REG Procedure
Model: MODEL1
Dependent Variable: dailypeak total

Number of Observations Read	41
Number of Observations Used	11
Number of Observations with Missing Values	30

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	3	182793	60931	13.15	0.0029
Error	7	32435	4633.53932		
Corrected Total	10	215228			

Root MSE	68.07011	R-Square	0.8493
Dependent Mean	2852.85664	Adj R-Sq	0.7847
Coeff Var	2.38603		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	106.77147	628.74725	0.17	0.8700
hot1	avgtemp-70	1	11.21889	9.53312	1.18	0.2777
prhightmp		1	23.20541	7.10112	3.27	0.0137
I_RPI		1	0.00520	0.00290	1.80	0.1156

Where:

- Hot 1 is the Daily average temperature less 70 degrees. This captures the impact of warm weather on loads.
- Prhightmp is the high temperature on the previous day. Repetitive high temperature days lead to higher loads.
- I_RPI is the Iowa Real Personal Income. Higher income leads to higher loads as consumers are more likely to use the comforts that electricity provides.

2A.1.6 IPL Monthly Peak

Table 2A.1.6 shows the model results.

Table 2A.1.6
Monthly Peak Parameters

REG PROC FOR IPL MONTHLY PEAK FORECAST MODEL

The REG Procedure
Model: MODEL1
Dependent Variable: peak total

Number of Observations Read	486
Number of Observations Used	128
Number of Observations with Missing Values	358

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Value	Pr > F
Model	14	13034494	931035	131.23	<.0001
Error	113	801702	7094.70497		
Corrected Total	127	13836195			

Root MSE	84.23007	R-Square	0.9421
Dependent Mean	2258.43957	Adj R-Sq	0.9349
Coeff Var	3.72957		

Parameter Estimates

Variable	Label	DF	Parameter Estimate	Standard Error	t Value	Pr > |t|
Intercept	Intercept	1	1501.55661	122.57608	12.25	<.0001
hdd		1	5.16970	0.94706	5.46	<.0001
cdd		1	39.80573	2.57193	15.48	<.0001
Feb		1	-45.08452	36.12040	-1.25	0.2145
Mar		1	-66.65420	40.38949	-1.65	0.1017
Apr		1	-102.86275	53.82861	-1.91	0.0585
May		1	-62.46112	68.18494	-0.92	0.3616
Jun		1	216.31799	72.73027	2.97	0.0036
Jul		1	332.54750	73.03706	4.55	<.0001
Aug		1	291.32091	73.84789	3.94	0.0001
Sep		1	232.73823	69.22911	3.36	0.0011
Oct		1	-27.40699	61.71829	-0.44	0.6578
Nov		1	24.09292	43.10465	0.56	0.5773
Dec		1	25.06535	37.05357	0.68	0.5001
I_RPI		1	0.00342	0.00103	3.34	0.0012

Where:

- hdd: Cedar Rapids Heating Degree Days is the monthly sum of the positive differences between 65 and the daily average of the high and low temperature. This variable measures the impact of cold temperature on sales.
- cdd: Cedar Rapids Cooling Degree Days is the monthly sum of the positive difference between the daily average of the high and low temperature and the base of 65. This variable measures the impact of warm temperatures on sales.
- Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, and Dec are monthly indicators that take the value of 1 for the

representative month and 0 in other months to represents systematic fluctuation in demand.

- I_RPI is the Iowa Real Personal Income. Higher income leads to higher loads as consumers are more likely to use the comforts that electricity provides.

2A.2 Model Changes

IPL made the following improvements in the forecasting process in 2013.

- **Calendar month data**: Previously, IPL's energy forecast matched billed sales by route to a "calculated" weather by route variable. The new process matches calendar month sales to calendar month weather, which reduces complexity in the modeling.
- **One regression model**: Previously, IPL used two different models for short-term and long-term forecasting, adding complexity to the process and models. The new process utilizes the short-term/regression model as the base for the long term forecast by extending the growth rate of the regression model from 2019 through 2029.
- **Single source weather data**: In the prior plan, IPL used weather from one source for historical data to match to the routes, while a separate source was used to calculate the normal calendar month values. The current forecast uses one source for weather. Please note there have been no changes to methods of calculating normal weather. (Base 65, 20-year normal.)
- **Consistent inputs**: In the prior plan, the number of years of historical data was not consistent between models. The current forecast uses ten years of historical data in all of the regression models.
- **Jurisdictional Allocation**: Previously, IPL allocated sales to the state jurisdictions based on historical sales. In the current plan, IPL ran regressions for IPL in total, and IA only. For the residential and commercial classes, IPL assigned the difference between the IA and IPL data as Minnesota sales. For industrial sales, given the relative size of the MN class, IPL utilized trending of past MN industrial sales.
- **Consensus Peak:** In the prior plan, IPL used one model to forecast the peak. This presumed that there is one "correct" relationship between peaking conditions and load. In the current plan, IPL uses multiple models to determine a consensus forecast of the peak.
- **Forecast of Internal Demand:** Previously IPL's forecasted peak demand excluded available (but not called) interruptible and direct load control. In the current model, IPL includes the interruptible and direct load control called during peak times, creating a theoretical peak, which is used in the forecast models. This leads to fewer adjustments to the data.

2A.4 Comparison to prior Plan

See table 2A.4.1 for a comparison of the Energy forecasts between the current and prior plan.

Table 2A.4.1
Comparison of Energy (GWH)

Year	2014 IRP	2012 IRP*	Variance	Percent
2012	NA	16,612	NA	NA
2013	NA	16,702	NA	NA
2014	16,928	16,415	513	3.1%
2015	17,115	16,554	561	3.4%
2016	17,274	16,715	559	3.3%
2017	17,428	16,897	531	3.1%
2018	17,585	17,056	529	3.1%
2019	17,728	17,235	493	2.9%
2020	17,884	17,405	479	2.8%
2021	18,041	17,572	469	2.7%
2022	18,200	17,719	481	2.7%
2023	18,360	17,883	477	2.7%
2024	18,522	18,068	454	2.5%
2025	18,685	18,258	427	2.3%
2026	18,850	18,430	420	2.3%
2027	19,016	18,614	402	2.2%
2028	19,184	NA	NA	NA
2029	19,353	NA	NA	NA

*2012 Baseload Diversification Study

See Table 2A.4.2 for a comparison of the Peak forecasts between the current and prior plan.

Table 2A.4.2
Comparison of Internal Demand
(MW)

Year	2014 IRP	2012 IRP*	Variance	Percent
2012	NA	3,053.5	NA	NA
2013	NA	3,056.8	NA	NA
2014	3,121.3	2,999.4	121.9	4.1%
2015	3,151.7	3,039.4	112.3	3.7%
2016	3,179.1	3,077.3	101.8	3.3%
2017	3,205.7	3,114.3	91.4	2.9%
2018	3,232.8	3,149.2	83.6	2.7%
2019	3,257.6	3,180.3	77.3	2.4%
2020	3,284.6	3,216.3	68.3	2.1%
2021	3,311.8	3,246.4	65.4	2.0%
2022	3,339.3	3,277.4	61.9	1.9%
2023	3,368.8	3,311.4	57.4	1.7%
2024	3,398.5	3,348.4	50.1	1.5%
2025	3,428.4	3,384.3	44.1	1.3%
2026	3,458.6	3,417.3	41.3	1.2%
2027	3,489.1	3,449.4	39.7	1.2%
2028	3,519.9	NA	NA	NA
2029	3,550.9	NA	NA	NA

*2012 Baseload Diversification Study

The current forecast is higher than the prior largely due to the retention of a large wholesale customer, a number of recent expansions at large industrial customer's locations which were unknown at the time of the prior filing, as well as recently observed peaks which have exceeded previously forecasted values.

DEMAND-SIDE MANAGEMENT (DSM)

This section of the IRP describes:

- Existing programs and levels of DSM in IPL's Minnesota and Iowa territory;
- The DSM program development and screening process;
- How existing levels of DSM are included in IPL's load forecast;
- Potential modifications to existing (Base) levels of Minnesota DSM under Low, Medium, and High scenarios. Demand and energy impacts and costs of these scenarios are discussed; and
- Benefit/Cost analysis for the existing and varied Minnesota DSM scenarios.

The section concludes by illustrating the rate impact of the Low, Medium and High scenarios relative to IPL's Base level of Minnesota DSM from the 2013-2015 Electric Conservation Improvement Plans, which currently meets the Minnesota minimum 1.5 percent savings goal.

3.0 Background

IPL implements conservation improvement programs/projects in Minnesota and Iowa based on the respective applicable regulatory policies in Minnesota and Iowa. These programs have been offered since the early 1990s, originally under its predecessor utilities, IES Utilities, Inc. (IES) and Interstate Power Company (IPC), and now as IPL.

IPL has been filing Electric Conservation Improvement Plans (CIPs) with the Minnesota Division of Energy Resources of the Department of Commerce (Department) since 1991. The most recently approved IPL CIP (Docket No. E-001/CIP-12-484) was filed with the Department on June 1, 2012, and was approved by the Director on October 19, 2012. It is a three-year plan, addressing the years 2013-2015. In 2012, the most recent year for which historical results are available, IPL achieved energy savings of 14,365,499 kWh and 2,466.9 kW in its Minnesota CIP plan. This compares to a goal of 12,940,477 kWh and 2,551 kW

IPL conducts energy conservation programs in Iowa according to 199 Iowa Administrative Code Chapter 35 and the five-year energy efficiency plan (EEP) it implements every five years pursuant to that administrative code, and as approved most recently by the IUB in Docket No. EEP-2012-0001, covering the time period from January 1, 2014 through December 31, 2018. For 2012 in Iowa, IPL achieved energy savings of 205,837,005 kWh and 328,185 kW, compared to the goal of 197,999,889 kWh and 337,140 kW.

Table 3.0.1 below lists the Shared Savings Project kWh savings, expenditures and IPL's minimum required expenditures for the period 2001 to 2012.

Table 3.0.1: IPL Minnesota Shared Savings Project Annual Savings and Associated Spending Compared to Minimum Spending Requirements

Year	Shared Savings Savings (kWh)	Shared Savings Spending ($)	Total Minimum Spending ($)
2001	22,173,525	$1,677,283	$734,364
2002	19,297,064	$2,005,663	$819,487
2003	20,623,638	$1,846,714	$819,487
2004	20,610,445	$2,222,896	$940,239
2005	20,555,132	$1,923,614	$940,239
2006	12,181,094	$1,442,003	$977,459
2007	14,239,216	$1,888,544	$977,459
2008	6,372,556	$1,268,202	$977,459
2009	4,577,593	$1,120,935	$977,459
2010	299,474	$313,877	$1,088,238
2011	2,867,422	$484,994	$1,088,238
2012	9,529,414	$1,489,996	$1,125,840

In each year through 2009, and again in 2012, the Shared Savings Project alone exceeded IPL's minimum required expenditures. IPL aggressively pursued opportunities in its Minnesota service territory. As the easier opportunities were exhausted, the cost of obtaining savings increased. Shared Savings activity is increasing, with significant improvement being observed in 2012. It is doubtful that the large savings of the early years will be replicated at a similar cost.

3.1 DSM Program Development Process for Minnesota and Iowa

IPL utilizes a process similar to many other utilities in developing DSM projects that are offered to its customers. At a high level, this process follows the following five steps:

1) Identify and gather data for commercially available energy efficient technologies;
2) Perform economic screening of energy efficient technologies;
3) Develop cost-effective energy efficiency projects for selected energy efficiency technologies;
4) Implement energy efficiency projects; and
5) Evaluate energy efficiency projects.

Until recently, IPL relied on a common set of data for conservation plans in both Minnesota and Iowa. The major process steps are performed as part of the Iowa EEP. Experience and data developed in the process was transferred to Minnesota. While the process is still transferable, Minnesota's development of a standardized measure savings database resulted in different energy savings between the two states for many of the measures. IPL recently updated its savings estimates in both Minnesota and Iowa.

3.1.1 Identify Energy Efficient Technologies

As noted above, the first step is to identify energy efficient technologies available in the marketplace. A listing of commercially available energy efficiency options is developed which addresses the common end-uses of a majority of the Company's customers.

The last extensive energy conservation technology search was conducted in 2012 as part of the Joint Utility Technology Assessment (Assessment), which was a collaborative among the three Iowa investor-owned utilities with input from various interested stakeholders (i.e., the consumer advocate, environmental groups, etc.). This 2012 Assessment was used in the preparation of IPL's 2014-2018 Iowa EEP. Similarly, the technologies, or measures identified in the previous Assessment performed in 2007, were used in the preparation of the 2009-2013 Iowa EEP.

The 2013-2015 CIP used results from the Minnesota Deemed Savings Database, the 2009-2013 Iowa EEP and where available, results consistent with the 2012 Assessment. The data for identified measures include assumptions regarding cost, weather-adjusted energy savings and measure life, thus eliminating the need for a quantitative screen, which had previously been performed prior to data gathering.

3.1.2 Perform Economic Screen

The economic screening process weighs the measure's cost against the benefits as determined by valuing energy and demand reductions at the Company's avoided cost. Any costs that might be needed to deliver the measure to the customer via a project are not included. The comprehensive economic screening of energy efficiency measures was conducted in 2012 as part of IPL's Iowa EEP. The measures surviving the economic screen in Iowa are consistent with those used in the Minnesota CIP. Complete results of the 2012 screening were not available in time to be considered in the 2013-2015 Minnesota CIP.

3.1.3 Develop Energy Efficiency Projects

Energy efficient measures that pass the economic screening process are packaged into projects. Detailed impacts and budgets are developed and a final project screening analysis is performed. The final screening weighs the cost of implementing a proposed project against the benefits as determined by the avoided cost of capacity and energy, from a societal perspective. The final screening process yields the projects that are subsequently bundled into the CIP in Minnesota and the EEP in Iowa.

3.1.4 Develop Alternative DSM Program Scenarios

Measure incentives and participation, along with project-level administrative costs are varied in a systematic manner to develop four alternative scenarios in Minnesota. Each scenario is constructed and evaluated with respect to the DSM cost-effectiveness tests to determine the impact of cost and participation on the test results. This scenario development and analysis is discussed further in Section 3.3.

3.1.5 Implement and Evaluate DSM Projects

The approved projects are offered to customers in the year for which they are approved. On April 1 of the year following implementation, a Status Report is filed with the Department detailing the participants, energy savings, cost and cost-effectiveness of each project. A Status Report for 2012 Electric and Gas CIP was filed on April 1, 2013. Evaluation procedures in Iowa are similar under the current plan.

3.2 DSM Plan Overview

The electric energy conservation plans that IPL implements in Minnesota and Iowa, although similar, are not identical. The plans for Minnesota and Iowa include the projects presented in Table 3.2.1 below.

TABLE 3.2.1: IPL Energy Conservation Projects

Project	IPL Iowa	IPL Minnesota
Residential Prescriptive Rebates	Yes	Yes
Residential Home Energy Assessment	Yes	Yes
Residential Change-a-Light	Yes	Yes
Residential Appliance Recycling	Yes	Yes
Residential New Construction	Yes	Yes
Multifamily	Yes	No
Livingwise	Yes	Yes
Residential Low Income (1)	Yes	Yes
Residential Direct Load Control	Yes	Yes
Nonresidential Prescriptive Rebates	Yes	Yes
Business Assessments	Yes	No
Non-Residential Custom	Yes	Yes
Commercial New Construction	Yes	Yes
C&I Shared Savings	No	Yes
Agricultural	Yes	Yes
Small Business Direct Install	Yes	Yes
Non-Residential Demand Response (2)	Yes	No
Outreach, Education and Training	Yes	No

(1) Iowa low-income programs include Weatherization, EnergyWise Education, Multifamily and Institutional Efficiency Improvements, and Home Energy Savers.
(2) Iowa – Nonresidential Interruptible Program

3.2.1 2013-2015 Energy Conservation Plans

Since this IRP is being filed early in 2014, any project changes resulting from the IRP would most likely be implemented in 2015 at the earliest. Therefore, a level of activity consistent with the approved 2013-2015 CIP is assumed for all scenarios in 2014. Differences in the various scenarios are first noted in 2015. The scenario to be defined as the Base scenario is consistent with the level of savings specified under Minnesota law. This CIP, along with the approved budget in Iowa, represents the level of activity that is projected to continue into the future for several years. The 2014 IPL estimated annual budget for energy conservation in Minnesota and Iowa is $78,219,669 for all projects. The Minnesota budget is $2,998,924. Table 3.2.2 below provides a listing of the approved 2014 Minnesota budget and the approved 2014 Iowa budget, by individual energy conservation and load management project.

TABLE 3.2.2: IPL Energy Conservation Program Annual Budget – 2014

Project	IPL Iowa	IPL Minnesota	Total
Residential Prescriptive Rebates	$9,120,931	$448,127	$9,569,058
Residential Home Energy Assessment	$732,171	$43,333	$775,504
Change-a-Light	$2,958,696	$0	$2,958,696
Residential Appliance Recycling	$1,702,379	$77,050	$1,779,429
Residential New Construction	$105,252	$26,067	$131,319
Multifamily	$112,840	$0	$112,840
Livingwise	In Education	$105,400	$105,400
Residential Low Income (1)	$825,047	$72,764	$897,811
Residential Direct Load Control	$2,552,877	$341,448	$2,894,325
Nonresidential Prescriptive Rebates	$5,418,560	$421,231	$5,839,791
Business Assessments	$1,974,872	$0	$1,974,872
Non-Residential Custom	$8,616,709	$0	$8,616,709
Commercial New Construction	$1,548,780	$159,000	$1,707,780
C&I Shared Savings	$0	$921,840	$921,840
Agricultural	$913,284	$165,164	$1,078,448
Small Business Direct Install	$0	$142,500	$142,500
Non-Residential Demand Response (2)	$24,473,965	$0	$24,473,965
Outreach, Education and Training	$2,339,013	$0	$2,339,013
Renewables	$10,454,991	$0	$10,454,991
Regulatory	$1,370,377	$75,000	$1,445,377
Total Direct Projects	$75,220,745	$2,998,924	$78,219,669

(1) Iowa low-income programs include Weatherization, EnergyWise Education, Multifamily and Institutional Efficiency Improvements, and Home Energy Savers.
(2) Iowa – Nonresidential Interruptible Program

Total projected energy and capacity savings for the company's energy conservation programs are 189,711,618 kWh and 343,255 kW. Table 3.2.3 below lists annual kWh savings, by project, for IPL's 2014 energy conservation plans in Minnesota and Iowa. Table 3.2.4 below lists annual kW savings, by project, for the 2014 CIP and EEP.

TABLE 3.2.3: IPL 2014 Energy Conservation Plan
Annual Energy Savings Estimates in kWh

Project	IPL Iowa	IPL Minnesota	Total
Residential Prescriptive Rebates	12,432,139	1,098,643	13,620,610
Residential Home Energy Assessment	2,412,222	72,051	2,487,816
Change-a-Light	9,054,481	0	9,054,481
Residential Appliance Recycling	11,096,756	831,379	11,853,152
Residential New Construction	215,398	42,793	258,191
Multifamily	151,170	0	151,170
Livingwise	In Education	524,362	524,362
Residential Low Income (1)	3,399,201	110,798	3,512,362
Residential Direct Load Control	500,022	8,773	502,852
Nonresidential Prescriptive Rebates	20,852,779	2,107,304	22,973,816
Business Assessments	2,907,140	0	2,907,140
Non-Residential Custom	68,567,883	0	68,567,883
Commercial New Construction	17,000,000	372,340	17,372,340
C&I Shared Savings	0	5,106,383	5,106,383
Agricultural	3,698,789	1,034,209	4,743,275
Small Business Direct Install	0	590,426	590,426
Non-Residential Demand Response (2)	5,400,000	0	5,400,000
Outreach, Education and Training	4,156,500	0	4,156,500
Renewables	15,967,676	0	15,967,676
Total Direct Projects	177,812,157	11,899,461	189,711,618

(1) Iowa low-income programs include Weatherization, EnergyWise Education, Multifamily and Institutional Efficiency Improvements, and Home Energy Savers.

(2) Iowa – Nonresidential Interruptible Program

TABLE 3.2.4: IPL 2014 Energy Conservation Program
Annual Capacity Savings Estimates in kW

Project	IPL Iowa	IPL Minnesota	Total
Residential Prescriptive Rebates	5,318	245	5,563
Residential Home Energy Assessment	186	39	225
Residential Change-a-Light	1,565	0	1,565
Residential Appliance Recycling	1,408	170	1,578
Residential New Construction	202	15	217
Multifamily	20	0	20
Livingwise	In Education	43	43
Residential Low Income (1)	629	15	644
Residential Direct Load Control	44,235	1,508	45,473
Nonresidential Prescriptive Rebates	1,661	195	1,856
Business Assessments	143	0	143
Non-Residential Custom	8,834	0	8,834
Commercial New Construction	4,323	85	4,408
C&I Shared Savings	0	777	777
Agricultural	477	236	713
Small Business Direct Install	0	153	153
Non-Residential Demand Response (2)	270,000	0	270,000
Outreach, Education and Training	775	0	775
Renewables	11,470	0	11,470
Total Direct Projects	339,776	3479	343,255

(1) Iowa low-income programs include Weatherization, EnergyWise Education, Multifamily and Institutional Efficiency Improvements, and Home Energy Savers.
(2) Iowa – Nonresidential Interruptible Program

3.2.2 2014 Energy Conservation DSM Projects

The DSM projects consistent with the above projections are described in the following subsections.

3.2.2(a) Energy Conservation DSM Project – Residential Prescriptive Rebates

This residential project provides prescriptive ($/unit) financial incentives for the purchase and installation of high efficiency appliances, building shell, lighting, heating, cooling and hot water measures. Much of the equipment featured is ENERGY STAR® qualified. The project is designed to promote energy efficient equipment purchases through the normal sales and distribution channels, i.e., dealers and installing contractors, to customers who are in the market for new equipment. Technologies have been selected for incentives based on their maturity, incremental equipment efficiency, and cost over standard equipment. The customer is given a number of high efficiency equipment options from which they may choose. Customers receive a rebate from IPL upon the utility's receipt of the rebate application and bill of sale.

3.2.2(b) Energy Conservation DSM Project – Residential Home Energy Assessment

This project provides informational and energy audit services for residential customers. The energy audit includes the installation of compact fluorescent bulbs, hot water heater measures (low flow shower head, faucet aerator, pipe insulation and hot water heater wrap), smart strips and programmable thermostats. The energy audit also includes an analysis of the cost-effectiveness of attic, foundation and duct insulation, as well as infiltration control. In addition, a toll-free telephone information call center is available to respond to customer, dealer and contractor questions pertaining to IPL’s energy efficiency projects. In Minnesota, a second tier audit that includes additional services such as a blower door test, combustion safety test and carbon monoxide check, and an infrared test is also available to customers. An energy services company with Minnesota certified auditors provides the home energy audits in Minnesota.

This project has an information component as well as the direct impact component described above. The information component has two parts. First, this project provides a DSM information center. The DSM information center provides a toll-free telephone service for customers in Minnesota and Iowa that is available from 8:00 AM to 5:00 PM Monday through Friday. The DSM information center also handles the distribution of DSM information literature and rebate payment forms. Second, IPL provides an Internet web site, alliantenergy.com, where customers can learn about the energy efficiency projects, rebate claim forms and links to other energy-efficiency information.

3.2.2(c) Energy Conservation DSM Project - Residential Change-a-Light

Change-a-Light is an upstream program for which IPL provides incentives directly to lighting manufacturers to reduce the purchase price of ENERGY STAR-rated, high efficiency lighting products at participating retail locations. The upstream incentive mechanism helps mitigate first costs as a barrier to program participation, makes purchasing high-efficiency lighting simple for customers and is offered year around.

IPL partners with retailers throughout its service territory to offer program-discounted compact fluorescent lamps and LEDs, and to promote the program to customers. Product discounts are applied at the register. IPL works with an implementation contractor to negotiate and coordinate with manufacturers and retailers, develop and lead promotional efforts, provide training and other on-site support to participating retailers and report sales data. Change-a-Light is offered in Minnesota as part of the Residential Prescriptive Rebates Project.

3.2.2(d) Energy Conservation DSM Project – Residential Appliance Recycling

This project is designed to remove spare and inefficient refrigerators, freezers and room air conditioners from operation in the IPL electric service territory and to provide safe disposal of these units. The project is also designed to prevent existing primary refrigerators from becoming secondary refrigerators when customers purchase new units. The environmentally responsible disposal of appliances involves the removal of CFCs for the refrigerant (and possibly the foam), the preparation of the refrigerant for reclamation or recycling, and the recycling of other materials such as the metal (and possibly the plastic) components.

IPL residential electric customers who own a qualifying refrigerator, freezer or room air conditioner unit are eligible to participate. To qualify, refrigerators and freezers must be a minimum of 10 cubic feet or larger, be operational and be in current use. IPL will pay for a maximum of two refrigerators, two freezers and two room air conditioners per address per year.

3.2.2(e) Energy Conservation DSM Project – Residential New Construction

The New Construction Project accelerates the incorporation of energy efficiency in the design, construction, and operation of single-family homes. The goal of the project is to produce a permanent improvement in "standard" design practices among building designers and owners that will continue without the need for short-term incentives. To encourage participation, builders or homeowners are offered rebates for the purchase and installation of high efficiency end-use equipment and building envelope measures in new residential dwellings. This project combines several of the measures from IPL's other main projects into new housing design and one of the builder options complies with ENERGY STAR guidelines. Homebuilders are encouraged to participate through incentive payments and education to install high efficiency equipment and to construct more energy-efficient homes. The measures are delivered through a package that is targeted to new homes that have electric water heating and/or electric space heating and are planning air conditioning.

3.2.2(f) Energy Conservation DSM Project – Multifamily (Iowa Only)

IPL offers a comprehensive suite of energy-efficiency services to address the unique needs of multifamily property owners, property managers and Landlords, supplementing its current program offering to the low-income multifamily sector. The Multifamily Program will expand IPL's energy-efficiency services to multifamily customers who do not qualify for low-income assistance. The program targets existing multifamily buildings with three or more units as well as new construction of multifamily buildings. The Multifamily Program includes three components:

1. A free energy assessment with direct installation of low-cost energy-efficiency measures for tenant units and common areas;
2. Prescriptive rebates for all non-low-income customers; and
3. A custom rebate component where recommended and warranted.

3.2.2(g) Energy Conservation DSM Project – Livingwise

This national school-based education program is currently being implemented in 23 other states and yields a variety of measurable energy and water savings results by assigning students to bring educational materials and information to their home, discussing the information with their parents and installing measures included in the kit. The program delivers a proven blend of teacher-designed classroom activities with hands-on home projects to install high efficiency devices and introduce resource-conscious behavior to students and their families. The program is cost-effective as evidenced by multiple measurement and verification studies for existing programs in multiple states including Minnesota, Iowa, Colorado, New Mexico, Texas and California.

3.2.2(h) Energy Conservation DSM Project – Residential Low Income

This project is designed to supplement the state-run, federal Weatherization Assistance Project (WAP) by funding the purchase and installation of low-cost water heater, lighting, refrigeration, insulation and other need-based measures, as appropriate, for WAP eligible households served by IPL in Minnesota and Iowa. These services have evolved into a project implemented through Community Action Programs (CAPs) in IPL's service territory. By using the CAPs' eligibility verification and service delivery system, IPL is able to leverage their efforts that are directed toward low-income customers.

IPL pays CAPs for the purchase and installation of efficiency measures in the homes of eligible IPL customers. CAPs are responsible for the identification of participants, purchase of materials and installation of all measures provided through this project. Components of this project include water heating, refrigeration, cooling and lighting efficiency measures, furnace, boiler and water heater replacement where IPL provides the respective fuel and insulation measures where IPL provides the heating fuel. While this project includes the replacement of delivered fuel appliances in Minnesota with more efficient delivered fuel appliances, the costs and equivalent electric savings are not considered in this Resource Plan.

3.2.2(i) Energy Conservation DSM Project – Residential Direct Load Control (DLC)

The DLC project operates during the peak summer season, May 15 to September 15. Participants in this load management project receive incentives in the form of bill credits on their June through September electric bills in return for allowing IPL to control their air conditioning cycling (central air conditioners and heat pumps) and their electric water heater equipment during system summer peak hours.

The project offers the following measures:

- Air conditioner cycling (every 15 minutes);
- Heat pump cycling (every 15 minutes); and
- Water heater direct load control (shut off during the entire control period).

3.2.2(j) Energy Conservation DSM Project – Nonresidential Prescriptive Rebates

This prescriptive rebate project offers commercial and industrial customers a set of financial incentives for specific energy-efficient building shell, lighting, appliances, heating, cooling and hot water heating measures. Much of the equipment featured is ENERGY STAR qualified. This project also provides rebates to assist customers in the environmentally safe disposal of lighting fixtures (Minnesota only). The lighting disposal rebate is restricted to the lighting measures for which a customer received a rebate. All commercial, governmental, industrial and nonprofit organizations are eligible to participate in this project. Incentives are paid for specific energy efficient equipment options. Equipment must be installed on the customer's premises and must not be purchased for resale.

This project also offers a Business Energy Assessment to guide customer to appropriate energy-efficiency projects. A walk-through analysis is performed at the customer's business to assess current energy use, provide customers with information on a variety of ways to reduce energy consumption, and offer recommendations for participating in other appropriate IPL non-residential projects with a customized report. The assessment also offers on-site installation of energy efficiency measures, including CFLs, faucet aerators, pipe insulation, smart strips, retrofit LED exit signs, vending machine controllers, pre-rinse sprayers, programmable thermostats and water heater blankets.

3.2.2(k) Energy Conservation DSM Project – Business Assessments (Iowa Only)

The Business Assessments Program offers free energy assessments by professional energy assessors, installation (where applicable) of free energy-efficiency measures and customer education to promote energy efficiency among IPL's nonresidential customers. Customers who participate in the Business Assessments Program may be eligible to receive:

- Information on their facility's energy performance and advice to help them prioritize investments in energy-efficiency upgrades;
- One-to-one education on energy use and conservation;
- Free, direct installation of energy-efficiency measures and enhanced incentives for installing lighting measures through the Small Business Direct Install Lighting Program; and
- A customized report that recommends and prioritizes energy-efficiency upgrades, provides a life-cycle cost analysis for recommended measures and indicates measures that may be eligible for IPL rebates.

3.2.2(l) Energy Conservation DSM Project – Non-Residential Custom Rebates

The purpose of this project is to provide customized energy-efficiency rebates to IPL's commercial and industrial customers to increase their competitiveness and ensure their sustainability. This project was approved within the Shared Savings project by the Department's Deputy Director on October 22, 2010. This project is limited to technologies and applications with paybacks of two years or more for Iowa customers and one year or more for Minnesota customers. IPL helps these customers identify energy efficiency opportunities in conventional end uses and their specific processes.

The IPL team works with the customers in calculating the energy savings for the proposed installation of the energy saving equipment. The project provides the targeted customers with a full range of services and products throughout their facilities that will be aimed at achieving total efficiency improvements rather than individual measure efficiency.

3.2.2(m) Energy Conservation DSM Project – Commercial New Construction

The objective of this project is to capture "lost opportunities" to reduce electric demand and energy usage in the commercial and industrial sector by providing customers with design assistance and rebates for the construction of energy-efficient buildings and facilities. This project covers both new buildings/facilities and buildings/facilities undergoing "major renovation," defined as buildings where multiple major systems are undergoing significant upgrades.

The target market for this project is new IPL commercial and industrial customers, as they make energy-related choices during building design. IPL introduced this project in Minnesota in 2010.

3.2.2(n) Energy Conservation DSM Alternative – C&I Shared Savings (Minnesota Only)

This existing project is directed toward existing and new commercial and industrial electric and gas firm-retail customers for the improvement of energy use. IPL evaluates and selects proposed projects based on a set of criteria outlined below. Financing is offered for the installation of a custom package of measures. Within this project, the customer is provided with a complete menu of energy efficient technologies to select the most appropriate solution to meet his or her needs.

This project is marketed to Commercial and Industrial customers under the following guidelines:

- The choice of projects to be funded is open-ended with a goal of obtaining as wide a variety of projects and recipients as possible. Projects that pass benefit/cost screening are funded. All projects in excess of $5,000 require prior approval by the project manager;
- Reducing customer payback of energy efficiency measures, as determined by individual circumstances, is also a criteria in determining the level of incentive and the proposals approved; and

- Successful project applicants, in most cases, are given 18 months to install measures that have been approved after which point they would lose IPL financing for the project.

3.2.2(o) Energy Conservation DSM Project – Agriculture

The purpose of this project is for IPL to help agricultural customers use energy more efficiently so that they can improve their productivity and profitability. This is accomplished through the application of energy efficiency technologies encouraged by rebates and demonstration farms.

The project operates in the following manner. IPL staff or vendor energy auditors visit farms to conduct energy audits. The results of the audit provide the basis for choosing specific technologies to promote to farms, to set rebate levels and to identify possible demonstration farms. Measures eligible for rebates include dairy equipment, fans and ventilation systems, heating and cooling, motors and drives, waterers and irrigation, lighting and other farm equipment.

3.2.2.(p) Energy Conservation DSM Project – Small Business Direct Install

A third-party vendor delivers a Small Business Direct Install Project to better reach the small business customer segment. The Small Business Direct Install Project is specifically designed to address the obstacles these business owners face when choosing efficient lighting, including limited financial resources, time, knowledge of lighting products, and access to quality contractors.

Customer entry into the project begins with a free, no-obligation lighting audit, which provides a customized report on current lighting energy usage and a lighting redesign proposal with projected energy-efficiency savings. Should a business owner choose to upgrade their lighting system, IPL provides rebates up to 80 percent of installed cost based on per kWh saved. Further, the third-party vendor offers a financing option for the remainder of the cost. To be eligible, businesses must have an electrical demand load and be in operation the entire calendar year.

3.2.2(q) Energy Conservation DSM Project – Non-Residential Demand Response (Iowa Only)

IPL provides large commercial and industrial customers an existing load management project. This offering is a contract-based interruptible tariff that provides IPL with flexible peak demand resources and supports the reliability of its distribution system. Through the project, IPL offers incentives to its large commercial and industrial customers who reduce their demands during times of system peak conditions or high market prices. The project is mature, successful, and has proven to be a reliable resource, providing IPL with a flexible means to manage its peak load.

IPL uses an automated notification system which has the capability to dispatch multiple notifications simultaneously for a curtailment event, warning or conclusion. IPL may call curtailment events on the basis of reliability, reducing peak demand, reducing energy usage and to test the capabilities of participating customers. Customers participating in the project benefit by helping improve system reliability and service for all of IPL's electric customers and receiving lower monthly energy bills provided by a bill credit received throughout the entire year.

3.2.2(r) Energy Conservation DSM Project – Outreach Education and Testing (IA Only)

Information, energy education and research are integral to IPL's continuous improvement process for managing its energy efficiency portfolio and marketing the project offerings. IPL's Iowa EEP incorporates a wide-range of non-targeted initiatives, that aim to raise general public awareness about energy efficiency; as well as targeted education and training activities that complement the incentive projects. Activities include Non-Targeted Energy Awareness and Information; School-Based Energy Education; Research, Development and Demonstration; Tree planting programs; Builder Training; Trade Ally Network; Hometown Rewards and Affinity Bright Ideas. IPL does include Minnesota trades and contractors in its Trade Ally Network program.

3.2.2(s) Energy Conservation DSM Project – Renewables (Iowa Only)

The Renewables pilot provided Iowa residential and commercial customers a rebate along with information and guidance regarding the costs, benefits and feasibility to install a renewable system at a customer's premise. As part of an energy efficiency plan, this project primarily sought to generate energy-efficiency savings beyond customer on-site generation. In an effort to ensure the focus remained first on energy efficiency, IPL offered a standard tier and a higher energy-efficiency tier of rebates, and also capped the rebate amount based on the customers' on-site energy needs, reduced for energy efficiency measures not implemented. However, due to the underperformance with regard to the energy efficiency component that was integral to the success of the project as an EEP program, the IUB allowed IPL to suspend the pilot beginning January 1, 2014.

3.2.2(t) Energy Conservation DSM Project –Regulatory

This project represents charges billed to IPL as assessments and third party projects not sponsored by IPL.

3.3 DSM Scenario Development and Analysis

Because IPL does not explicitly model DSM as a resource to be selected in the IRP modeling, the question remains whether the amount of DSM implemented by IPL is an optimum amount from the resource planning perspective. Since the DSM that IPL implements in Iowa is determined by the IUB's administration of Iowa statute, any variation would need to be in Minnesota.

Since 2003, IPL has addressed this issue by examining the variation in plan impacts relative to plan spending. In the present study a Base Case and three alternative spending and impact scenarios are developed. This study methodology is used for the scenario development in this IRP. The four scenarios are then provided to the Resource Planning group for analysis.

3.3.1 Scenario Definition and Associated Input Parameters

Four scenarios were developed for this analysis. These scenarios are defined as:

- Base - This scenario is identical to the 2013-2015 CIP, with the exception of the Low Income propane to electric equivalent costs and savings, which are removed because they do not represent savings to the IPL system. Costs are escalated by the Consumer Price Index (CPI) each year, beginning in 2016. The measures from the 2013-2015 CIP are used as proxies for measures to be implemented in the future. While the actual measures may vary, the overall spending level and savings level are expected to be representative of the scenario. The Low Income and Direct Load Control projects are not varied by scenario, but are kept at the 2013-2015 level except for the annual inflation cost escalations, beginning in 2016. The Low Income Project is based on customer need and is not easily varied. The Direct Load Control Project was designed to meet its potential by 2015. Increases to the Project are not reasonable. Decreasing the Project in 2015 alone would yield a minimal difference with respect to Resource Planning. This scenario is used as the basis for determining the other scenarios. It currently meets the minimum 1.5 percent savings requirements.
- Minimum Spending - Incentives are decreased 40 percent from the Base scenario. Administrative costs decrease 35 percent. Participation decreases 50 percent. This scenario has spending consistent with minimum spending required by current law. It does not meet the minimum savings requirements.
- Medium - Incentives increase 100 percent. Administrative costs increase 110 percent. Participation increases 30 percent. This scenario meets the minimum savings requirements. Individual measures may differ for those shown.

- High - Incentives increase 160 percent. Administrative costs increase 570 percent above the Base level. Participation doubles. All percentages are relative to the base scenario.

The incentives are not increased to a level greater than the incremental participant cost for any measure. The Medium and High scenarios are developed to be consistent with the Utility Net Benefit correction factors originally agreed to with the Department and other utilities in Docket No. E,G999/CI-08-133. The Low Income and Direct Load Control project assumptions are not varied. Scenario variations do not begin until 2015. IPL believes that this is the earliest date changes could be made after an Order in this IRP Case is received.

Table 3.3.1 below lists the number of participants assumed for each Project of each scenario.

TABLE 3.3.1: Participation by Scenario (New Participants per Year) in 2015

	Project Participation (Number of Measures)			
Project Description	**Base Case**	**High**	**Medium**	**Minimum Spending**
1. Residential Prescriptive Rebates	19,285	38,570	25,070.5	9642.5
2. Residential Home Energy Assessment	871	1,742	1,132.3	435.5
3. Residential New Construction	25	50	32.5	12.5
4. Appliance Recycling	1,236	2,472	1,606.8	618.0
5. Livingwise	11,160	22,320	14,508.0	5,580.0
6. Low Income	482	482	482.0	482.0
7. Nonresidential Prescriptive Rebates	3,583	7,166	4,657.9	1,791.5
8. Commercial New Construction	1	2	1.3	0.5
9. Small Business Direct Install	1	2	1.3	0.5
10. Agricultural	2,773	5,546	3,604.9	1,386.5
11. Shared Savings	1	2	1.3	0.5
12. Direct Load Control	2,117	2,117	2,117.0	2,117.0
Total	41,535	80,471	53,216	22,067

Each plan assumes implementation at a constant level through the year 2029 for all scenarios, including the Base. Plans projecting impacts this far out are suspect in terms of achievable impacts in the later years. IPL has a small service territory in Minnesota and has implemented an aggressive DSM plan for many years. It is not prudent to assume continued aggressive implementation without verification that the savings potential exists.

Table 3.3.2 below lists the customer and dealer incentives for each Project of each scenario.

TABLE 3.3.2: Incentive Variation by Scenario - 2015

Project Description	Project Incentive Costs			
	Base Case	High	Medium	Minimum Spending
1. Residential Prescriptive Rebates	$246,527	$948,822	$546,031	$73,958
2. Residential Home Energy Assessment	$36,033	$98,818	$62,921	$10,810
3. Residential New Construction	$18,667	$97,068	$48,534	$5,600
4. Appliance Recycling	$58,550	$178,900	$116,285	$17,565
5. Livingwise	$97,500	$195,000	$126,750	$29,250
6. Low Income	$41,334	$41,334	$41,334	$41,334
7. Nonresidential Prescriptive Rebates	$251,623	$896,758	$520,175	$75,487
8. Commercial New Construction	$91,000	$473,200	$236,600	$27,300
9. Small Business Direct Install	$70,000	$280,000	$182,000	$21,000
10. Agricultural	$72,821	$310,187	$167,133	$21,846
11. Shared Savings	$600,000	$3,120,000	$1,560,000	$180,000
12. Direct Load Control	$77,458	$77,458	$77,458	$77,458
Total	$1,661,513	$6,717,545	$3,685,221	$581,608

Table 3.3.3 below lists the annual administrative costs for each Project, under each scenario.

TABLE 3.3.3: Administrative Costs by Scenario in 2015

	Project Administrative Costs			
Project Description	**Base Case**	**High**	**Medium**	**Minimum Spending**
1. Residential Prescriptive Rebates	$201,600	$1,350,720	$423,360	$131,040
2. Residential Home Energy Assessment	$2,800	$18,760	$5,880	$1,820
3. Residential New Construction	$7,400	$49,580	$15,540	$4,810
4. Appliance Recycling	$23,800	$159,460	$49,980	$15,470
5. Livingwise	$7,900	$52,930	$16,590	$5,135
6. Low Income	$9,630	$9,630	$9,630	$9,630
7. Nonresidential Prescriptive Rebates	$169,840	$1,137,928	$356,664	$110,396
8. Commercial New Construction	$66,000	$442,200	$138,600	$42,900
9. Small Business Direct Install	$72,500	$485,750	$152,250	$47,125
10. Agricultural	$92,343	$618,698	$193,920	$60,023
11. Shared Savings	$320,880	$2,149,896	$673,848	$208,572
12. Direct Load Control	$383,409	$383,409	$383,409	$383,409
Total	$1,358,102	$6,858,961	$2,419,671	$1,020,330

Total plan spending for each scenario in 2015 is shown in Table 3.3.4 below. Differences between Table 3.3.4 and Table 3.2.2 are caused by non-impact electric expenses and Low Income propane replacement measures which are removed.

TABLE 3.3.4: Total Project Costs by Scenario in 2015

	TOTAL PROJECT COSTS			
Project Description	**Base**	**High**	**Medium**	**Minimum Spending**
1. Residential Prescriptive Rebates	$448,127	$2,299,542	$969,391	$204,998
2. Residential Home Energy Assessment	$38,833	$117,578	$68,801	$12,630
3. Residential New Construction	$26,067	$146,648	$64,074	$10,410
4. Appliance Recycling	$82,350	$338,360	$166,265	$33,035
5. Livingwise	$105,400	$247,930	$143,340	$34,385
6. Low Income	$50,964	$50,964	$50,964	$50,964
7. Nonresidential Prescriptive Rebates	$421,463	$2,034,686	$876,839	$185,883
8. Commercial New Construction	$157,000	$915,400	$375,200	$70,200
9. Small Business Direct Install	$142,500	$765,750	$334,250	$68,125
10. Agricultural	$165,164	$928,885	$361,053	$81,869
11. Shared Savings	$920,880	$5,269,896	$2,233,848	$388,572
12. Direct Load Control	$460,867	$460,867	$460,867	$460,867
Total	$3,019,615	$13,576,506	$6,104,892	$1,601,938

Project costs are escalated at the GDP escalator for each year beginning in 2016.

Individual measure cost assumptions, by scenario, are shown in Appendix 3A. Individual measure incentive costs are shown in Appendix 3B. Measure participation is shown in Appendix 3C. Measure energy savings, which are constant among scenarios are shown in Appendix 3D.

3.3.2 Load Forecast Adjustment

IPL's load forecast assumes that the DSM efforts of the past several years will continue throughout the forecast horizon. Although not critical to an evaluation of DSM itself, any new DSM embedded in the forecast should be removed prior to IRP modeling of the scenarios to avoid double counting. It is difficult to determine the amount of DSM embedded in the forecast, as savings cannot be measured and verification estimates are only good at the time they are taken. Over time, the level of DSM savings has varied. It is estimated that the MW of embedded DSM is approximated by the Base scenario MW. Therefore the DSM added by the Base scenario offsets the embedded DSM removed from the forecast. In the IRP modeling, the base forecast is assumed to include Base scenario DSM. The High, Medium and Minimum Spending scenarios are modeled by considering the difference in MWh, MW and program dollars between the base scenario and the scenario being modeled. It should be noted that the MW difference between the Base scenario and High scenario is less than 27 MW in 2029.

3.3.3 Scenario Results

Each of the scenarios is evaluated over a period from 2013 through 2048, with implementation extending through 2029. It is necessary to discount programs past the year of implementation to balance the costs incurred in the first year with benefits in later years. Table 3.3.5 below lists the 2015 annual energy and peak savings, at the generator, for each project in each scenario. The year 2015 is the first year that the scenarios vary. For all projects except Direct Load Control, the savings represent impacts due to measures implemented in 2015. Direct Load Control impacts are the cumulative impacts of measures implemented through 2015 and thus include 2014 impacts. These are reported in this manner to be consistent with the reported costs. Unlike other measures, Direct Load Control participants are paid incentives each month of the four-month program season (May 15 through September) for each year they remain in the project. The cumulative savings for each entire plan in 2018, the last year of the action plan, are also shown. The cumulative savings include 2014 impacts and also factor in losses due to end of measure life.

TABLE 3.3.5: Energy and Peak Savings by Scenario in 2015

Project Description	TOTAL SAVINGS							
	Base Case		High		Medium		Minimum Spending	
	KWh	KW	KWh	KW	KWh	KW	KWh	KW
1. Res Prescriptive Rebates	1,026,752	244	2,053,504	487	1,334,778	317	513,376	122
2. Res Home Energy Assessment	69,217	41	138,434	82	89,982	53	34,609	21
3. Res New Const	42,792	15	85,585	30	55,630	20	21,396	8
4. Appliance Recycling	914,185	187	1,828,370	374	1,188,440	243	457,092	94
5. Livingwise	524,361	43	1,048,723	86	681,670	56	262,181	21
6. Low Income	30,488	11	30,488	11	30,488	11	30,488	11
7. Nonres Prescriptive Rebates	2,095,729	235	4,191,458	470	2,724,448	306	1,047,865	118
8. Com New Const	372,341	84	744,681	169	484,043	110	186,171	42
9. Small Business Direct Install	590,425	153	1,180,851	306	767,553	199	295,212	76
10. Agricultural	1,025,908	235	2,051,816	469	1,333,680	305	512,954	117
11. Shared Savings	5,106,383	777	10,212,766	1,553	6,638,298	1,010	2,553,191	388
12. Direct Load Control	13,031	1,863	13,031	1,863	13,031	1,863	13,031	1,863
Total	11,811,612	3,887	23,579,707	5,900	15,342,041	4,491	5,927,566	2,880
Total in 2018 (incl. 2014, 2015, 2016 and 2017)	58,743,592	12,690	105,677,182	20,709	72,820,669	15,096	35,281,797	8,681

The preceding tables indicate the following:

- In the Base case, almost 48 percent of the total demand savings are obtained from the Direct Load Control Project. Since this project does not vary by scenario, the scenario variation is determined by other projects. The Direct Load Control and Shared Savings projects account for a minimum of 58 percent of demand savings in the High scenario to a maximum of 78 percent of demand savings in the Minimum Spending scenario; and
- In the high scenario, higher project spending and participation levels increase demand savings due to the conservation projects by approximately 99 percent above the Base. However, because the direct Load Control savings do not vary, total demand savings increase by 52 percent from the Base scenario to the High scenario. The differences between the Base and the Medium and Minimum Spending scenarios will be even less. Over time, the conservation projects will account for a much greater portion of total demand savings, between 89 percent for the minimum Spending scenario to 97 percent for the High scenario in 2029.

The annual kW and kWh savings, as well as annual program costs for each of the four Minnesota DSM scenarios are shown in Appendix 3E. Appendix 3E also shows the additional annual kWh savings and associated cost in each scenario, required to maintain the 2029 level of savings through the year 2064. This additional savings and cost is referred to as “edge effects” and is used in the IRP modeling to maintain consistency with the supply resources.

In this IRP, the scenarios were included in a supply base case that included direct CO_2 costs beginning in 2017, as well as a base supply case without direct costing of CO_2. In addition to potentially impacting the scenario selection, the CO_2 costs also impact the cost-effectiveness tests. Benefit/cost results for each scenario are shown in Table 3.3.6 below for the supply plan that does not include any direct costs due to CO_2.

TABLE 3.3.6: Benefit/Cost Results by Scenario – No Direct CO_2

Test Perspective	2014 Dollars Lifetime Benefits	Lifetime Costs	Net Benefits	B/C Ratio
Base Scenario				
Societal	$198,713,575	$65,439,526	$133,274,049	3.04
Utility Cost	$113,504,331	$29,731,247	$83,773,084	3.82
Ratepayer Impact Measure	$113,504,331	$138,504,859	($25,000,528)	0.82
Participant	$155,056,081	$42,359,091	$112,696,990	3.66
High Scenario				
Societal	$376,230,939	$185,843,717	$190,387,222	2.02
Utility Cost	$211,876,683	$134,807,057	$77,069,626	1.57
Ratepayer Impact Measure	$211,876,683	$342,489,168	($130,612,485)	0.62
Participant	$334,442,765	$81,542,733	$252,900,032	4.10
Medium Scenario				
Societal	$251,968,784	$93,899,912	$158,068,872	2.68
Utility Cost	$143,016,046	$60,439,907	$82,576,139	2.37
Ratepayer Impact Measure	$143,016,046	$198,886,067	($55,870,021)	0.72
Participant	$214,698,229	$54,229,495	$160,468,734	3.96
Minimum Spending Scenario				
Societal	$109,954,894	$37,564,866	$72,390,028	2.93
Utility Cost	$64,318,157	$15,620,696	$48,697,461	4.12
Ratepayer Impact Measure	$64,318,157	$74,940,058	($10,621,901)	0.86
Participant	$81,569,779	$23,225,101	$58,344,678	3.51

Benefit/cost results for each scenario are shown in Table 3.3.7 below for the supply plan that includes the direct costs due to CO_2.

TABLE 3.3.7: Benefit/Cost Results by Scenario – Direct CO_2 Costs

	2014 Dollars			
Test Perspective	Lifetime Benefits	Lifetime Costs	Net Benefits	B/C Ratio
Base Scenario				
Societal	$223,560,138	$65,437,602	$158,122,536	3.42
Utility Cost	$128,179,405	$29,731,247	$98,448,158	4.31
Ratepayer Impact Measure	$128,179,405	$151,189,611	($23,010,206)	0.85
Participant	$168,997,852	$42,359,091	$126,638,761	3.99
High Scenario				
Societal	$424,563,424	$185,840,188	$238,723,236	2.28
Utility Cost	$240,239,416	$134,807,057	$105,432,359	1.78
Ratepayer Impact Measure	$240,239,416	$366,921,486	($126,682,070)	0.65
Participant	$361,333,494	$81,542,733	$279,790,761	4.43
Medium Scenario				
Societal	$283,861,123	$93,897,507	$189,963,616	3.02
Utility Cost	$161,797,407	$60,439,907	$101,357,500	2.68
Ratepayer Impact Measure	$161,797,407	$215,095,091	($53,297,684)	0.75
Participant	$232,524,695	$54,229,495	$178,295,200	4.29
Minimum Spending Scenario				
Societal	$123,058,495	$37,563,745	$85,494,750	3.28
Utility Cost	$72,149,400	$15,620,696	$56,528,704	4.62
Ratepayer Impact Measure	$72,149,400	$81,751,029	($9,601,629)	0.88
Participant	$89,037,085	$23,225,101	$65,811,984	3.83

The benefit/cost results indicate the following:

- The Societal, Utility Cost, and Participant tests indicate that the overall program portfolio is cost effective for all scenarios. This suggests that the effects of varying budget, incentives, and participants do not impact the overall cost effectiveness of the projects;
- For the Utility Cost test, the program portfolio becomes less cost effective when going from the low to the high scenario. This suggests diminishing returns when increasing the incentive levels. Industry experience indicates that participation rates do not increase in proportion to the funding and incentive levels;
- In the Societal test, there is a moderate decrease in the cost effectiveness as the amount of spending increases. This is caused by the increasing administrative costs;

- The Participant Test increases in cost effectiveness as incentives increase in the Medium and High Scenarios; and
- The Ratepayer Impact Measure test is not cost effective for any scenario. The present value of the revenue loss and program costs is greater than the present value of the energy and capacity savings.

Project level benefit/cost results are shown in Appendix 3F for both the no CO_2 and direct CO_2 cases.

Examining the results of the Ratepayer Impact Measure Test can provide additional insight. An approximation of relative rate impacts caused by each DSM scenario can be calculated from the results of the cost-effectiveness evaluations. Figure 3.3.1 below illustrates the impact on average system rate in the year 2018, relative to the Base Scenario. The rate impacts assume program costs are expensed in the year incurred and also account for energy and capacity savings realized. They represent the change in rates in the year 2018, in 2018 dollars, due to the various DSM scenarios in both the no carbon and carbon cases. The rate of the High Scenario is 1.62¢/kWh greater than the Base Case rate in 2017. The introduction of carbon costing does not change the relative rate impacts among the scenarios, but does impact the overall rate impact. Although the Minimum Spending Scenario is not permitted under current law, it provides an important basis for comparison of all possible DSM scenarios.

FIGURE 3.3.1: Rate Impacts by Scenario in the Year 2018

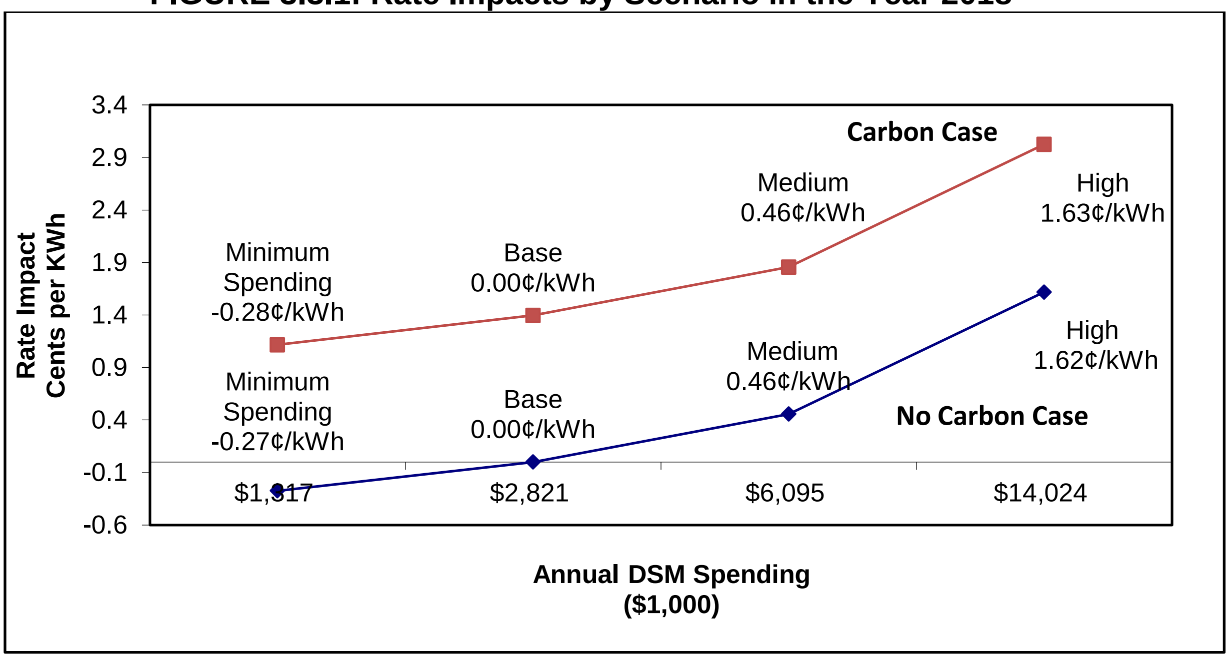


Figure 3.3.1 indicates that rate impact increases at an increasing rate as DSM spending increases. Since the Base scenario is assumed consistent with the sales forecast, rates will not change. However rates will be higher in the

Medium and the High scenario. Although greater DSM spending will lower costs, the total sales over which these costs can be recovered decrease by a greater percentage, thus increasing rates. On page 4 of its decision on IPL's 2005 Resource Plan (Docket No. E-001/RP-05-2029), the Commission noted the following:

> The record shows that by 2010 the rate impact of the High Scenario would exceed the rate impact of the Base Case Scenario by $.017 cents/kWh. It also shows that even under the Base Case Scenario, by 2010 Company spending on demand-side management will exceed the minimum required under Minnesota law by .21 cents kWh. These are significant rate impacts whose costs must be weighed against the benefits of the energy savings they would produce.

In the 2005 IRP, the High Scenario yielded an additional 19,500,000 kWh savings, compared to the Base Scenario, over the five year period for which the 0.17¢/kWh was calculated. In this 2014 IRP, the High Scenario represents a much more aggressive plan, with cumulative savings 44,000,000 kWh greater than the Base Scenario over the five year period of 2014 – 2018. This results in the much greater rate impact differential of 1.6¢/kWh between the Base and High Scenarios. The results of the IRP EGEAS modeling using these four DSM scenarios are shown in Appendix 3G and further discussed in Section 6.5v.

		Measure Cost ($) 2015			
		Base	**High**	**Medium**	**Min. Spend**
1. Residential Prescriptive Rebates					
Central AC - Aggregate - 2 tons		721.82	802.04	771.96	696.76
Geo Heat Pumps - Agg.		5,642.33	5,958.07	5,839.67	5,543.67
Air Source Heat Pumps - Agg.		1,005.36	1,005.35	1,005.35	1,005.36
Programmable Thermostats					
Electric		39.00	45.40	43.00	37.00
Combined		39.00	45.40	43.00	37.00
Windows - Assume 10.5 sq ft					
Electric		39.20	44.32	42.40	37.60
Combined		39.20	44.32	42.40	37.60
CFLs		1.74	1.74	1.74	1.74
LEDs - Interior standard		24.00	24.00	24.00	24.00
LEDs - interior specialty		28.00	28.00	28.00	28.00
LEDs - exterior		36.00	36.00	36.00	36.00
Room AC		54.00	60.40	58.00	52.00
Water Heaters - electric tank		51.06	51.06	51.06	51.06
Refrigerators		62.00	74.80	70.00	58.00
Freezers		58.00	64.40	62.00	56.00
Light Fixtures 60W-15W		47.20	52.32	50.40	45.60
Clothes Washers					
Electric		258.00	258.00	258.00	258.00
Combined		258.00	258.00	258.00	258.00
Dishwashers					
Electric		18.00	18.00	18.00	18.00
Combined		18.00	18.00	18.00	18.00
ECM Motors					
New 1/2 HP		500.00	500.00	500.00	500.00
Existing small		185.00	185.00	185.00	185.00
2. Home Energy Assessment					
Attic Insulation					
Electric heat		1,131.00	1,227.00	1,191.00	1,101.00
Combined customer		1,131.00	1,227.00	1,191.00	1,101.00
Foundation Insulation					
Combined customer		1,131.00	1,227.00	1,191.00	1,101.00
Infiltration					
Electric heat		285.00	285.00	285.00	285.00
Combined customer		285.00	285.00	285.00	285.00
Duct insulation					
Electric heat		285.00	285.00	285.00	285.00
Combined customer		285.00	285.00	285.00	285.00
CFLs		1.74	1.74	1.74	1.74
Water heater measures					
Aerator - electric		3.50	3.50	3.50	3.50
Showerhead - electric		6.75	6.75	6.75	6.75
Pipe insulation - electric		3.00	3.00	3.00	3.00
Blanket electric		19.00	19.00	19.00	19.00
Smart strips		22.00	22.00	22.00	22.00
Programmable thermostats					
Electric		80.00	80.00	80.00	80.00
Combined		80.00	80.00	80.00	80.00

		Measure Cost ($) 2015			
		Base	**High**	**Medium**	**Min. Spend**
3. Residential New Construction		3,587.00	3,587.00	3,587.00	3,587.00
4. Recycling					
Refrigerators		75.00	75.00	75.00	75.00
Freezers		75.00	75.00	75.00	75.00
AC		50.00	50.00	50.00	50.00
5. Livingwise					
CFL		6.00	6.00	6.00	6.00
Water Heater Measures					
Aerators - Electric		6.00	6.00	6.00	6.00
Showerheads - Electric		6.00	6.00	6.00	6.00
Handouts		22.42	22.42	22.42	22.42
6. Low Income					
CFLs		1.74	1.74	1.74	1.74
Refrigerator replacement		800.00	800.00	800.00	800.00
A/C replacement - Assume SEER 14		444.50	444.50	444.50	444.50
Water heater replacement					
Electric		51.06	51.06	51.06	51.06
Water heater measures					
Aerator - electric		3.50	3.50	3.50	3.50
Showerhead - electric		5.50	5.50	5.50	5.50
Attic Insulation					
Electric heat					
Combined customer		1,000.00	1,000.00	1,000.00	1,000.00
Wall Insulation					
Combined customer		2,400.00	2,400.00	2,400.00	2,400.00
Foundation Insulation					
Combined customer		350.00	350.00	350.00	350.00
Weatherization		720.00	720.00	720.00	720.00
Windows		36.00	36.00	36.00	36.00
Energy Wise - Education		0.00	0.00	0.00	0.00
Unallocated		0.00	0.00	0.00	0.00

		Measure Cost ($) 2015			
		Base	**High**	**Medium**	**Min. Spend**
7. NonResidential Prescriptive Rebates					
Central AC - 3 tons		775.94	818.60	802.61	762.61
Geothermal Heat Pumps (		5,553.00	5,885.80	5,761.00	5,449.00
Air Source Heat Pumps - Agg.		1,033.11	1,151.69	1,107.22	996.06
Room AC		54.00	60.40	58.00	52.00
Lighting					
CFLs		1.74	1.74	1.74	1.74
Light Fixtures 100W-26W		85.20	90.32	88.40	83.60
T-8 Fluorescent Fixtures with electronic ballasts		64.90	68.48	67.14	63.78
High Performance T8		29.99	35.24	33.27	28.35
T-5 Fluorescent Fixtures with electronic ballasts		57.81	61.67	60.22	56.61
High Bay Fluorescent Fixtures above 15 ft		411.44	432.94	424.88	404.72
Pulse Start Metal halide (<250 watts in old plan)		177.36	186.96	183.36	174.36
Metal Halide Replacement Lamp, 360 Watt to replace 400 watt		11.48	12.25	11.96	11.24
LED exit sign		103.42	104.70	104.22	103.02
Occupancy sensors		78.20	83.32	81.40	76.60
LED Lighting - 2014 Except Exterior - Use for all 3 Yrs		27.67	30.23	29.27	26.87
LEDs - bulbs - interior standard		25.60	28.16	27.20	24.80
LEDs - interior specialty		29.60	32.16	31.20	28.80
LEDs - exterior		37.60	40.16	39.20	36.80
LED desklamp - 2014 - USE FOR ALL YEARS		21.60	24.16	23.20	20.80
LED Refrigerator case lights - per Foot of Case		28.56	28.56	28.56	28.56
Refrigerators		62.00	74.80	70.00	58.00
Freezers		54.00	54.00	54.00	54.00
Programmable thermostats					
Electric		39.00	45.40	43.00	37.00
Combined		39.00	45.40	43.00	37.00
Windows					
Electric - assume gas heat		39.20	44.32	42.40	37.60
Combined		39.20	44.32	42.40	37.60
Water Heaters - electric tank		59.06	71.86	67.06	55.06
Commercial Food Service - Ice Machine - assume ice making head		156.00	181.60	172.00	148.00
Commercial Food Service - Refrig and Freezer Doors		195.50	211.50	205.50	190.50
Commercial Food Service - Cooking - Electric		2,205.00	2,301.00	2,265.00	2,175.00
Commercial Food Service - Dishwashing - Electric					
High Temp - Electric Water Heat		490.00	566.80	538.00	466.00
Attic Insulation					
Electric heat		7,143.00	7,143.00	7,143.00	7,143.00
Combined customer		7,143.00	7,143.00	7,143.00	7,143.00
Wall Insulation					
Electric heat		7,143.00	7,143.00	7,143.00	7,143.00
Combined customer		7,143.00	7,143.00	7,143.00	7,143.00
Infiltration					
Electric heat		2,143.00	2,143.00	2,143.00	2,143.00
Combined customer		2,143.00	2,143.00	2,143.00	2,143.00
Data Center Items					
Data Center - thin client		5.80	7.08	6.60	5.40
CFLs - Audit		1.74	1.74	1.74	1.74
Water Heater Measures - Electric					
Aerator - electric		3.75	3.75	3.75	3.75
Pipe insulation - electric		3.00	3.00	3.00	3.00
Blanket - electric		19.00	19.00	19.00	19.00
Retrofit LED Exit sign		102.62	102.62	102.62	102.62
Vending Machine controller		180.00	180.00	180.00	180.00
Pre-rinse sprayer - elect WH (1.0 GPM)		39.00	39.00	39.00	39.00
Smart strips		22.00	22.00	22.00	22.00
Programmable thermostats					
Electric		80.00	80.00	80.00	80.00
Combined		80.00	80.00	80.00	80.00
High Vol low speed fans		3,088.75	3,280.75	3,208.75	3,028.75
Circulating Fans		280.00	280.00	280.00	280.00
C&I Appliance Recycling					
Refrigerators		125.00	205.00	175.00	100.00
Freezers		125.00	205.00	175.00	100.00
AC		100.00	140.00	125.00	87.50
Clothes Washers					
Electric		266.00	278.80	274.00	262.00
Combined		266.00	278.80	274.00	262.00
Dishwashers					
Electric		20.40	24.24	22.80	19.20
Combined		20.40	24.24	22.80	19.20
ECM Motors					
ECM Motors - OEM Large		500.00	500.00	500.00	500.00
ECM Motors - OEM Small		500.00	500.00	500.00	500.00
ECM Motors - Replacement Large		230.00	230.00	230.00	230.00
ECM Motors - Replacement Small		185.00	185.00	185.00	185.00
Variable Frequency Drives		4,475.38	4,475.37	4,475.37	4,475.38
Motors - Replace on Failure & New Construction		273.08	305.21	293.16	263.04

		Measure Cost ($) 2015			
		Base	High	Medium	Min. Spend
8. Commercial New Construction		251,947.67	251,947.67	251,947.67	251,947.67
9. Small Business Direct Install		140,000.00	140,000.00	140,000.00	140,000.00
10. Agricultural					
Lighting					
Infrared Brooder Lamps		5.00	5.00	5.00	5.00
CFLs		1.74	1.74	1.74	1.74
Light Fixtures 100W-26W		82.00	82.00	82.00	82.00
T-8 Fluorescent Fixtures with electronic ballasts		84.26	118.81	105.86	73.46
High Performance T8		26.72	26.73	26.73	26.72
T-5 Fluorescent Fixtures with electronic ballasts		55.72	56.23	56.04	55.56
High Bay Fluorescent Fixtures above 15 ft		398.00	398.00	398.00	398.00
Pulse Start Metal halide (<250 watts in old plan)		171.86	172.66	172.36	171.61
Metal Halide Replacement Lamp, 360 Watt to replace 400 watt		11.00	11.00	11.00	11.00
LED exit sign		103.12	103.92	103.62	102.87
Occupancy sensors		75.40	76.04	75.80	75.20
LEDs - bulbs - interior standard		24.00	24.00	24.00	24.00
LEDs - interior specialty		28.00	28.00	28.00	28.00
LEDs - exterior		36.00	36.00	36.00	36.00
LED desklamp		20.00	20.00	20.00	20.00
Ventilation measures					
Fans controlled by thermostat		307.06	338.44	326.67	297.26
Fans uncontrolled		277.25	277.25	277.25	277.25
Fan controls		40.00	40.00	40.00	40.00
HVLS fans		2,800.00	2,902.86	2,864.29	2,767.86
Circulating Fans		280.00	280.00	280.00	280.00
Dairy Measures					
Automatic milker takeoff ($5 per cow)		15.00	15.00	15.00	15.00
Milk precooler ($3.40 per cow)		10.00	10.00	10.00	10.00
VSD vacuum pump ($5 per cow)		12.00	12.00	12.00	12.00
Scroll compressor (per ton)		400.00	400.00	400.00	400.00
Other farm measures					
Livestock waterer		137.00	143.40	141.00	135.00
Tractor heater timer		20.00	20.00	20.00	20.00
Refrigerators		54.00	54.00	54.00	54.00
Freezers		54.00	54.00	54.00	54.00
11. Shared Savings		2,100,000.00	2,100,000.00	2,100,000.00	2,100,000.00
12. Direct Load Cotrol					
AC		0.00	0.00	0.00	0.00
Water Heat		0.00	0.00	0.00	0.00

		Customer and Dealer Incentives per Measure ($) 2015			
		Base	High	Medium	Min. Spend
1. Residential Prescriptive Rebates					
Central AC - Aggregate - 2 tons		363.47	802.04	726.93	218.08
Geo Heat Pumps - Agg.		1,469.33	3,820.27	2,938.67	881.60
Air Source Heat Pumps - Agg.		335.71	872.86	671.43	201.43
Programmable Thermostats					
Electric		29.00	45.40	43.00	17.40
Combined		14.50	22.70	21.50	8.70
Windows - Assume 10.5 sq ft					
Electric		23.20	44.32	42.40	13.92
Combined		11.60	22.16	21.20	6.96
CFLs		2.00	2.00	2.00	1.20
LEDs - Interior standard		10.00	24.00	20.00	6.00
LEDs - interior specialty		10.00	26.00	20.00	6.00
LEDs - exterior		10.00	26.00	20.00	6.00
Room AC		29.00	60.40	58.00	17.40
Water Heaters - electric tank		50.00	51.06	51.06	30.00
Refrigerators		58.00	74.80	70.00	34.80
Freezers		29.00	64.40	58.00	17.40
Light Fixtures 60W-15W		23.20	52.32	46.40	13.92
Clothes Washers					
Electric		50.00	130.00	100.00	30.00
Combined		10.00	26.00	20.00	6.00
Dishwashers					
Electric		15.00	18.00	18.00	9.00
Combined		7.50	9.00	9.00	4.50
ECM Motors					
New 1/2 HP		50.00	130.00	100.00	30.00
Existing small		50.00	130.00	100.00	30.00
2. Home Energy Assessment					
Attic Insulation					
Electric heat		810.00	1,227.00	1,191.00	486.00
Combined customer		405.00	613.50	595.50	243.00
Foundation Insulation					
Combined customer		405.00	613.50	595.50	243.00
Infiltration					
Electric heat		200.00	285.00	285.00	120.00
Combined customer		100.00	142.50	142.50	60.00
Duct insulation					
Electric heat		200.00	285.00	285.00	120.00
Combined customer		100.00	142.50	142.50	60.00
CFLs		7.00	7.00	7.00	4.20
Water heater measures					
Aerator - electric		3.50	3.50	3.50	2.10
Showerhead - electric		6.75	6.75	6.75	4.05
Pipe insulation - electric		3.00	3.00	3.00	1.80
Blanket electric		19.00	19.00	19.00	11.40
Smart strips		22.00	22.00	22.00	13.20
Programmable thermostats					
Electric		80.00	80.00	80.00	48.00
Combined		40.00	40.00	40.00	24.00

		Customer and Dealer Incentives per Measure ($) 2015			
		Base	**High**	**Medium**	**Min. Spend**
3. Residential New Construction		746.68	1,941.37	1,493.36	448.01
4. Recycling					
Refrigerators		50.00	75.00	75.00	30.00
Freezers		50.00	75.00	75.00	30.00
AC		25.00	50.00	50.00	15.00
5. Livingwise					
CFL		6.00	6.00	6.00	3.60
Water Heater Measures					
Aerators - Electric		6.00	6.00	6.00	3.60
Showerheads - Electric		6.00	6.00	6.00	3.60
Handouts		22.42	22.42	22.42	13.45
6. Low Income					
CFLs		6.00	6.00	6.00	6.00
Refrigerator replacement		800.00	800.00	800.00	800.00
A/C replacement - Assume SEER 14		2,350.00	2,350.00	2,350.00	2,350.00
Water heater replacement					
Electric		896.00	896.00	896.00	896.00
Water heater measures					
Aerator - electric		3.50	3.50	3.50	3.50
Showerhead - electric		5.50	5.50	5.50	5.50
Attic Insulation					
Electric heat		0.00	0.00	0.00	0.00
Combined customer		250.00	250.00	250.00	250.00
Wall Insulation					
Combined customer		450.00	450.00	450.00	450.00
Foundation Insulation					
Combined customer		87.50	87.50	87.50	87.50
Weatherization		180.00	180.00	180.00	180.00
Windows		77.50	77.50	77.50	77.50
Energy Wise - Education		0.00	0.00	0.00	0.00
Unallocated		7,450.00	7,450.00	7,450.00	7,450.00

	Customer and Dealer Incentives per Measure ($) 2015			
	Base	**High**	**Medium**	**Min. Spend**
7. NonResidential Prescriptive Rebates				
Central AC - 3 tons	193.33	502.67	386.67	116.00
Geothermal Heat Pumps (	1,508.00	3,920.80	3,016.00	904.80
Air Source Heat Pumps - Agg.	344.44	895.56	688.89	206.67
Room AC	29.00	60.40	58.00	17.40
Lighting				
CFLs	1.50	1.74	1.74	0.90
Light Fixtures 100W-26W	23.20	60.32	46.40	13.92
T-8 Fluorescent Fixtures with electronic ballasts	16.24	68.48	32.48	9.74
High Performance T8	23.80	35.24	33.27	14.28
T-5 Fluorescent Fixtures with electronic ballasts	17.47	45.43	34.94	10.48
High Bay Fluorescent Fixtures above 15 ft	97.44	253.34	194.88	58.46
Pulse Start Metal halide (<250 watts in old plan)	43.50	113.10	87.00	26.10
Metal Halide Replacement Lamp, 360 Watt to replace 400 watt	3.48	9.05	6.96	2.09
LED exit sign	5.80	15.08	11.60	3.48
Occupancy sensors	23.20	60.32	46.40	13.92
LED Lighting - 2014 Except Exterior - Use for all 3 Yrs	11.60	29.16	23.20	6.96
LEDs - bulbs - interior standard	11.60	28.16	23.20	6.96
LEDs - interior specialty	11.60	30.16	23.20	6.96
LEDs - exterior	11.60	30.16	23.20	6.96
LED desklamp - 2014 - USE FOR ALL YEARS	11.60	24.16	23.20	6.96
LED Refrigerator case lights - per Foot of Case	2.00	5.20	4.00	1.20
Refrigerators	58.00	74.80	70.00	34.80
Freezers	25.00	54.00	50.00	15.00
Programmable thermostats				
Electric	29.00	45.40	43.00	17.40
Combined	14.50	22.70	21.50	8.70
Windows				
Electric - assume gas heat	23.20	44.32	42.40	13.92
Combined	11.60	22.16	21.20	6.96
Water Heaters - electric tank	58.00	71.86	67.06	34.80
Commercial Food Service - Ice Machine - assume ice making head	116.00	181.60	172.00	69.60
Commercial Food Service - Refrig and Freezer Doors	110.00	211.50	205.50	66.00
Commercial Food Service - Cooking - Electric	435.00	1,131.00	870.00	261.00
Commercial Food Service - Dishwashing - Electric				
High Temp - Electric Water Heat	348.00	566.80	538.00	208.80
Attic Insulation				
Electric heat	5,000.00	7,143.00	7,143.00	3,000.00
Combined customer	500.00	714.30	714.30	300.00
Wall Insulation				
Electric heat	5,000.00	7,143.00	7,143.00	3,000.00
Combined customer	500.00	714.30	714.30	300.00
Infiltration				
Electric heat	1,500.00	2,143.00	2,143.00	900.00
Combined customer	150.00	214.30	214.30	90.00
Data Center Items				
Data Center - thin client	5.80	7.08	6.60	3.48
CFLs - Audit	7.00	7.00	7.00	4.20
Water Heater Measures - Electric				
Aerator - electric	3.75	3.75	3.75	2.25
Pipe insulation - electric	3.00	3.00	3.00	1.80
Blanket - electric	19.00	19.00	19.00	11.40
Retrofit LED Exit sign	102.62	102.62	102.62	61.57
Vending Machine controller	180.00	180.00	180.00	108.00
Pre-rinse sprayer - elect WH (1.0 GPM)	39.00	39.00	39.00	23.40
Smart strips	22.00	22.00	22.00	13.20
Programmable thermostats				
Electric	80.00	80.00	80.00	48.00
Combined	40.00	40.00	40.00	24.00
High Vol low speed fans	870.00	2,262.00	1,740.00	522.00
Circulating Fans	43.75	113.75	87.50	26.25
C&I Appliance Recycling				
Refrigerators	125.00	205.00	175.00	75.00
Freezers	125.00	205.00	175.00	75.00
AC	100.00	140.00	125.00	60.00
Clothes Washers				
Electric	58.00	150.80	116.00	34.80
Combined	11.60	30.16	23.20	6.96
Dishwashers				
Electric	17.40	24.24	22.80	10.44
Combined	8.70	12.12	11.40	5.22
ECM Motors				
ECM Motors - OEM Large	50.00	130.00	100.00	30.00
ECM Motors - OEM Small	50.00	130.00	100.00	30.00
ECM Motors - Replacement Large	50.00	130.00	100.00	30.00
ECM Motors - Replacement Small	50.00	130.00	100.00	30.00
Variable Frequency Drives	1,732.50	4,475.37	3,465.00	1,039.50
Motors - Replace on Failure & New Construction	145.58	305.21	291.16	87.35

		Customer and Dealer Incentives per Measure ($) 2015			
		Base	High	Medium	Min. Spend
8. Commercial New Construction		91,000.00	236,600.00	182,000.00	54,600.00
9. Small Business Direct Install		70,000.00	140,000.00	140,000.00	42,000.00
10. Agricultural					
Lighting					
Infrared Brooder Lamps		5.00	5.00	5.00	3.00
CFLs		1.50	1.74	1.74	0.90
Light Fixtures 100W-26W		20.00	52.00	40.00	12.00
T-8 Fluorescent Fixtures with electronic ballasts		35.60	92.56	71.20	21.36
High Performance T8		20.69	26.73	26.73	12.41
T-5 Fluorescent Fixtures with electronic ballasts		15.38	39.99	30.76	9.23
High Bay Fluorescent Fixtures above 15 ft		84.00	218.40	168.00	50.40
Pulse Start Metal halide (<250 watts in old plan)		38.00	98.80	76.00	22.80
Metal Halide Replacement Lamp, 360 Watt to replace 400 watt		3.00	7.80	6.00	1.80
LED exit sign		5.50	14.30	11.00	3.30
Occupancy sensors		20.40	53.04	40.80	12.24
LEDs - bulbs - interior standard		10.00	24.00	20.00	6.00
LEDs - interior specialty		20.00	28.00	28.00	12.00
LEDs - exterior		30.00	36.00	36.00	18.00
LED desklamp		15.00	20.00	20.00	9.00
Ventilation measures					
Fans controlled by thermostat		142.20	338.44	284.40	85.32
Fans uncontrolled		98.75	256.75	197.50	59.25
Fan controls		20.00	40.00	40.00	12.00
HVLS fans		814.29	2,117.14	1,628.57	488.57
Circulating Fans		43.75	113.75	87.50	26.25
Dairy Measures					
Automatic milker takeoff ($5 per cow)		5.00	13.00	10.00	3.00
Milk precooler ($3.40 per cow)		3.40	8.84	6.80	2.04
VSD vacuum pump ($5 per cow)		5.00	12.00	10.00	3.00
Scroll compressor (per ton)		250.00	400.00	400.00	150.00
Other farm measures					
Livestock waterer		44.00	114.40	88.00	26.40
Tractor heater timer		10.00	20.00	20.00	6.00
Refrigerators		50.00	54.00	54.00	30.00
Freezers		25.00	54.00	50.00	15.00
11. Shared Savings		600,000.00	1,560,000.00	1,200,000.00	360,000.00
12. Direct Load Cotrol					
AC		24.86	24.86	24.86	24.86
Water Heat		6.28	6.28	6.28	6.28

		Number of Measures or Other Participant Units 2015			
		Base	**High**	**Medium**	**Min. Spend**
1. Residential Prescriptive Rebates					
Central AC - Aggregate - 2 tons		225.00	450.00	292.50	112.50
Geo Heat Pumps - Agg.		15.00	30.00	19.50	7.50
Air Source Heat Pumps - Agg.		14.00	28.00	18.20	7.00
Programmable Thermostats					
Electric		90.00	180.00	117.00	45.00
Combined		150.00	300.00	195.00	75.00
Windows - Assume 10.5 sq ft					
Electric		1,000.00	2,000.00	1,300.00	500.00
Combined		800.00	1,600.00	1,040.00	400.00
CFLs		15,170.00	30,340.00	19,721.00	7,585.00
LEDs - Interior standard		20.00	40.00	26.00	10.00
LEDs - interior specialty		3.00	6.00	3.90	1.50
LEDs - exterior		1.00	2.00	1.30	0.50
Room AC		12.00	24.00	15.60	6.00
Water Heaters - electric tank		80.00	160.00	104.00	40.00
Refrigerators		550.00	1,100.00	715.00	275.00
Freezers		50.00	100.00	65.00	25.00
Light Fixtures 60W-15W		20.00	40.00	26.00	10.00
Clothes Washers					
Electric		400.00	800.00	520.00	200.00
Combined		100.00	200.00	130.00	50.00
Dishwashers					
Electric		400.00	800.00	520.00	200.00
Combined		100.00	200.00	130.00	50.00
ECM Motors					
New 1/2 HP		75.00	150.00	97.50	37.50
Existing small		10.00	20.00	13.00	5.00
2. Home Energy Assessment					
Attic Insulation					
Electric heat		2.00	4.00	2.60	1.00
Combined customer		50.00	100.00	65.00	25.00
Foundation Insulation					
Combined customer		2.00	4.00	2.60	1.00
Infiltration		30.00			
Electric heat		1.00	2.00	1.30	0.50
Combined customer		28.00	56.00	36.40	14.00
Duct insulation					
Electric heat		1.00	2.00	1.30	0.50
Combined customer		8.00	16.00	10.40	4.00
CFLs		600.00	1,200.00	780.00	300.00
Water heater measures					
Aerator - electric		15.00	30.00	19.50	7.50
Showerhead - electric		7.00	14.00	9.10	3.50
Pipe insulation - electric		5.00	10.00	6.50	2.50
Blanket electric		2.00	4.00	2.60	1.00
Smart strips		100.00	200.00	130.00	50.00
Programmable thermostats					
Electric		20.00	40.00	26.00	10.00
Combined		30.00	60.00	39.00	15.00

		Number of Measures or Other Participant Units 2015			
		Base	**High**	**Medium**	**Min. Spend**
3. Residential New Construction		25.00	50.00	32.50	12.50
4. Recycling					
Refrigerators		816.00	1,632.00	1,060.80	408.00
Freezers		290.00	580.00	377.00	145.00
AC		130.00	260.00	169.00	65.00
5. Livingwise					
CFL		5,580.00	11,160.00	7,254.00	2,790.00
Water Heater Measures					
Aerators - Electric		1,860.00	3,720.00	2,418.00	930.00
Showerheads - Electric		1,860.00	3,720.00	2,418.00	930.00
Handouts		1,860.00	3,720.00	2,418.00	930.00
6. Low Income					
CFLs		400.00	400.00	400.00	400.00
Refrigerator replacement		15.00	15.00	15.00	15.00
A/C replacement - Assume SEER 14		4.00	4.00	4.00	4.00
Water heater replacement					
Electric		1.00	1.00	1.00	1.00
Water heater measures					
Aerator - electric		15.00	15.00	15.00	15.00
Showerhead - electric		10.00	10.00	10.00	10.00
Attic Insulation					
Electric heat					
Combined customer		10.00	10.00	10.00	10.00
Wall Insulation					
Combined customer		10.00	10.00	10.00	10.00
Foundation Insulation					
Combined customer		2.00	2.00	2.00	2.00
Weatherization		8.00	8.00	8.00	8.00
Windows		6.00	6.00	6.00	6.00
Energy Wise - Education		50.00	50.00	50.00	50.00
Unallocated		1.00	1.00	1.00	1.00

		Number of Measures or Other Participant Units 2015			
		Base	**High**	**Medium**	**Min. Spend**
7. NonResidential Prescriptive Rebates					
Central AC - 3 tons		9.00	18.00	11.70	4.50
Geothermal Heat Pumps (		3.00	6.00	3.90	1.50
Air Source Heat Pumps - Agg.		9.00	18.00	11.70	4.50
Room AC		2.00	4.00	2.60	1.00
Lighting					
CFLs		300.00	600.00	390.00	150.00
Light Fixtures 100W-26W		30.00	60.00	39.00	15.00
T-8 Fluorescent Fixtures with electronic ballasts		5.00	10.00	6.50	2.50
High Performance T8		879.00	1,758.00	1,142.70	439.50
T-5 Fluorescent Fixtures with electronic ballasts		565.00	1,130.00	734.50	282.50
High Bay Fluorescent Fixtures above 15 ft		150.00	300.00	195.00	75.00
Pulse Start Metal halide (<250 watts in old plan)		10.00	20.00	13.00	5.00
Metal Halide Replacement Lamp, 360 Watt to replace 400 watt		5.00	10.00	6.50	2.50
LED exit sign		2.00	4.00	2.60	1.00
Occupancy sensors		10.00	20.00	13.00	5.00
LED Lighting - 2014 Except Exterior - Use for all 3 Yrs		56.00	112.00	72.80	28.00
LEDs - bulbs - interior standard		25.00	50.00	32.50	12.50
LEDs - interior specialty		30.00	60.00	39.00	15.00
LEDs - exterior		20.00	40.00	26.00	10.00
LED desklamp - 2014 - USE FOR ALL YEARS		1.00	2.00	1.30	0.50
LED Refrigerator case lights - per Foot of Case		324.00	648.00	421.20	162.00
Refrigerators		5.00	10.00	6.50	2.50
Freezers		5.00	10.00	6.50	2.50
Programmable thermostats					
Electric		5.00	10.00	6.50	2.50
Combined		5.00	10.00	6.50	2.50
Windows					
Electric - assume gas heat		65.00	130.00	84.50	32.50
Combined		30.00	60.00	39.00	15.00
Water Heaters - electric tank		1.00	2.00	1.30	0.50
Commercial Food Service - Ice Machine - assume ice making head		1.00	2.00	1.30	0.50
Commercial Food Service - Refrig and Freezer Doors		2.00	4.00	2.60	1.00
Commercial Food Service - Cooking - Electric		2.00	4.00	2.60	1.00
Commercial Food Service - Dishwashing - Electric					
High Temp - Electric Water Heat		1.00	2.00	1.30	0.50
Attic Insulation					
Electric heat		20.00	40.00	26.00	10.00
Combined customer		5.00	10.00	6.50	2.50
Wall Insulation					
Electric heat		5.00	10.00	6.50	2.50
Combined customer		1.00	2.00	1.30	0.50
Infiltration					
Electric heat		5.00	10.00	6.50	2.50
Combined customer		4.00	8.00	5.20	2.00
Data Center Items					
Data Center - thin client		1.00	2.00	1.30	0.50
CFLs - Audit		200.00	400.00	260.00	100.00
Water Heater Measures - Electric					
Aerator - electric		7.00	14.00	9.10	3.50
Pipe insulation - electric		2.00	4.00	2.60	1.00
Blanket - electric		2.00	4.00	2.60	1.00
Retrofit LED Exit sign		10.00	20.00	13.00	5.00
Vending Machine controller		10.00	20.00	13.00	5.00
Pre-rinse sprayer - elect WH (1.0 GPM)		10.00	20.00	13.00	5.00
Smart strips		25.00	50.00	32.50	12.50
Programmable thermostats					
Electric		20.00	40.00	26.00	10.00
Combined		15.00	30.00	19.50	7.50
High Vol low speed fans		8.00	16.00	10.40	4.00
Circulating Fans		4.00	8.00	5.20	2.00
C&I Appliance Recycling		5.00	10.00	6.50	2.50
Refrigerators		3.00	6.00	3.90	1.50
Freezers		1.00	2.00	1.30	0.50
AC		1.00	2.00	1.30	0.50
Clothes Washers					
Electric		200.00	400.00	260.00	100.00
Combined		50.00	100.00	65.00	25.00
Dishwashers					
Electric		250.00	500.00	325.00	125.00
Combined		100.00	200.00	130.00	50.00
ECM Motors					
ECM Motors - OEM Large		10.00	20.00	13.00	5.00
ECM Motors - OEM Small		75.00	150.00	97.50	37.50
ECM Motors - Replacement Large		10.00	20.00	13.00	5.00
ECM Motors - Replacement Small		10.00	20.00	13.00	5.00
Variable Frequency Drives		8.00	16.00	10.40	4.00
Motors - Replace on Failure & New Construction		10.00	20.00	13.00	5.00

		Number of Measures or Other Participant Units 2015			
		Base	High	Medium	Min. Spend
8. Commercial New Construction		1.00	2.00	1.30	0.50
9. Small Business Direct Install		1.00	2.00	1.30	0.50
10. Agricultural					
Lighting					
Infrared Brooder Lamps		75.00	150.00	97.50	37.50
CFLs		300.00	600.00	390.00	150.00
Light Fixtures 100W-26W		43.00	86.00	55.90	21.50
T-8 Fluorescent Fixtures with electronic ballasts		5.00	10.00	6.50	2.50
High Performance T8		1,019.00	2,038.00	1,324.70	509.50
T-5 Fluorescent Fixtures with electronic ballasts		565.00	1,130.00	734.50	282.50
High Bay Fluorescent Fixtures above 15 ft		250.00	500.00	325.00	125.00
Pulse Start Metal halide (<250 watts in old plan)		10.00	20.00	13.00	5.00
Metal Halide Replacement Lamp, 360 Watt to replace 400 watt		5.00	10.00	6.50	2.50
LED exit sign		2.00	4.00	2.60	1.00
Occupancy sensors		10.00	20.00	13.00	5.00
LEDs - bulbs - interior standard		25.00	50.00	32.50	12.50
LEDs - interior specialty		30.00	60.00	39.00	15.00
LEDs - exterior		20.00	40.00	26.00	10.00
LED desklamp		1.00	2.00	1.30	0.50
Ventilation measures					
Fans controlled by thermostat		58.00	116.00	75.40	29.00
Fans uncontrolled		4.00	8.00	5.20	2.00
Fan controls		40.00	80.00	52.00	20.00
HVLS fans		7.00	14.00	9.10	3.50
Circulating Fans		4.00	8.00	5.20	2.00
Dairy Measures					
Automatic milker takeoff ($5 per cow)		90.00	180.00	117.00	45.00
Milk precooler ($3.40 per cow)		50.00	100.00	65.00	25.00
VSD vacuum pump ($5 per cow)		150.00	300.00	195.00	75.00
Scroll compressor (per ton)		5.00	10.00	6.50	2.50
Other farm measures					
Livestock waterer		2.00	4.00	2.60	1.00
Tractor heater timer		1.00	2.00	1.30	0.50
Refrigerators		1.00	2.00	1.30	0.50
Freezers		1.00	2.00	1.30	0.50
11. Shared Savings		1.00	2.00	1.30	0.50
12. Direct Load Cotrol					
AC		2,964.00	2,964.00	2,964.00	2,964.00
Water Heat		602.00	602.00	602.00	602.00

		Per Measure Annual Energy Savings (KWh) 2015			
		Base	**High**	**Medium**	**Min. Spend**
1. Residential Prescriptive Rebates					
Central AC - Aggregate - 2 tons		220.80	220.80	220.80	220.80
Geo Heat Pumps - Agg.		11,198.77	11,198.77	11,198.77	11,198.77
Air Source Heat Pumps - Agg.		1,529.43	1,529.43	1,529.43	1,529.43
Programmable Thermostats					
Electric		183.00	183.00	183.00	183.00
Combined		183.00	183.00	183.00	183.00
Windows - Assume 10.5 sq ft					
Electric		29.00	29.00	29.00	29.00
Combined		26.00	26.00	26.00	26.00
CFLs		25.53	25.53	25.53	25.53
LEDs - Interior standard		24.42	24.42	24.42	24.42
LEDs - interior specialty		41.07	41.07	41.07	41.07
LEDs - exterior		51.00	51.00	51.00	51.00
Room AC		43.00	43.00	43.00	43.00
Water Heaters - electric tank		120.00	120.00	120.00	120.00
Refrigerators		83.00	83.00	83.00	83.00
Freezers		42.00	42.00	42.00	42.00
Light Fixtures 60W-15W		55.50	55.50	55.50	55.50
Clothes Washers					
Electric		224.00	224.00	224.00	224.00
Combined		25.00	25.00	25.00	25.00
Dishwashers					
Electric		60.00	60.00	60.00	60.00
Combined		26.00	26.00	26.00	26.00
ECM Motors					
New 1/2 HP		785.00	785.00	785.00	785.00
Existing small		785.00	785.00	785.00	785.00
2. Home Energy Assessment					
Attic Insulation					
Electric heat		2,017.00	2,017.00	2,017.00	2,017.00
Combined customer		249.00	249.00	249.00	249.00
Foundation Insulation					
Combined customer		172.00	172.00	172.00	172.00
Infiltration					
Electric heat		1,173.00	1,173.00	1,173.00	1,173.00
Combined customer		179.00	179.00	179.00	179.00
Duct insulation					
Electric heat		792.00	792.00	792.00	792.00
Combined customer		111.00	111.00	111.00	111.00
CFLs		25.53	25.53	25.53	25.53
Water heater measures					
Aerator - electric		171.00	171.00	171.00	171.00
Showerhead - electric		418.00	418.00	418.00	418.00
Pipe insulation - electric		16.00	16.00	16.00	16.00
Blanket electric		166.00	166.00	166.00	166.00
Smart strips		100.00	100.00	100.00	100.00
Programmable thermostats					
Electric		183.00	183.00	183.00	183.00
Combined		183.00	183.00	183.00	183.00

		Per Measure Annual Energy Savings (KWh) 2015			
		Base	**High**	**Medium**	**Min. Spend**
3. Residential New Construction		1,609.00	1,609.00	1,609.00	1,609.00
4. Recycling					
Refrigerators		844.00	844.00	844.00	844.00
Freezers		479.00	479.00	479.00	479.00
AC		244.00	244.00	244.00	244.00
5. Livingwise					
CFL		24.00	24.00	24.00	24.00
Water Heater Measures					
Aerators - Electric		30.00	30.00	30.00	30.00
Showerheads - Electric		163.00	163.00	163.00	163.00
Handouts		0.00	0.00	0.00	0.00
6. Low Income					
CFLs		25.53	25.53	25.53	25.53
Refrigerator replacement		320.00	320.00	320.00	320.00
A/C replacement - Assume SEER 14		156.00	156.00	156.00	156.00
Water heater replacement					
Electric		120.00	120.00	120.00	120.00
Water heater measures					
Aerator - electric		171.00	171.00	171.00	171.00
Showerhead - electric		418.00	418.00	418.00	418.00
Attic Insulation					
Electric heat					
Combined customer		229.00	229.00	229.00	229.00
Wall Insulation					
Combined customer		11.00	11.00	11.00	11.00
Foundation Insulation					
Combined customer		45.00	45.00	45.00	45.00
Weatherization		439.00	439.00	439.00	439.00
Windows		26.00	26.00	26.00	26.00
Energy Wise - Education		0.00	0.00	0.00	0.00
Unallocated		0.00	0.00	0.00	0.00

		Per Measure Annual Energy Savings (KWh) 2015			
		Base	High	Medium	Min. Spend
7. NonResidential Prescriptive Rebates					
Central AC - 3 tons		451.67	451.67	451.67	451.67
Geothermal Heat Pumps (		8,998.00	8,998.00	8,998.00	8,998.00
Air Source Heat Pumps - Agg.		1,587.56	1,587.56	1,587.56	1,587.56
Room AC		60.00	60.00	60.00	60.00
Lighting					
CFLs		113.22	113.22	113.22	113.22
Light Fixtures 100W-26W		122.10	122.10	122.10	122.10
T-8 Fluorescent Fixtures with electronic ballasts		227.80	227.80	227.80	227.80
High Performance T8		39.73	39.73	39.73	39.73
T-5 Fluorescent Fixtures with electronic ballasts		186.57	186.57	186.57	186.57
High Bay Fluorescent Fixtures above 15 ft		1,212.00	1,212.00	1,212.00	1,212.00
Pulse Start Metal halide (<250 watts in old plan)		1,737.26	1,737.26	1,737.26	1,737.26
Metal Halide Replacement Lamp, 360 Watt to replace 400 watt		164.28	164.28	164.28	164.28
LED exit sign		369.50	369.50	369.50	369.50
Occupancy sensors		315.46	315.46	315.46	315.46
LED Lighting - 2014 Except Exterior - Use for all 3 Yrs		135.10	135.10	135.10	135.10
LEDs - bulbs - interior standard		98.79	98.79	98.79	98.79
LEDs - interior specialty		166.50	166.50	166.50	166.50
LEDs - exterior		51.00	51.00	51.00	51.00
LED desklamp - 2014 - USE FOR ALL YEARS		101.01	101.01	101.01	101.01
LED Refrigerator case lights - per Foot of Case		17.33	17.33	17.33	17.33
Refrigerators		83.00	83.00	83.00	83.00
Freezers		42.00	42.00	42.00	42.00
Programmable thermostats					
Electric		264.00	264.00	264.00	264.00
Combined		264.00	264.00	264.00	264.00
Windows					
Electric - assume gas heat		27.00	27.00	27.00	27.00
Combined		27.00	27.00	27.00	27.00
Water Heaters - electric tank		158.00	158.00	158.00	158.00
Commercial Food Service - Ice Machine - assume ice making head		1,197.00	1,197.00	1,197.00	1,197.00
Commercial Food Service - Refrig and Freezer Doors		646.00	646.00	646.00	646.00
Commercial Food Service - Cooking - Electric		7,878.00	7,878.00	7,878.00	7,878.00
Commercial Food Service - Dishwashing - Electric					
High Temp - Electric Water Heat		8,416.00	8,416.00	8,416.00	8,416.00
Attic Insulation					
Electric heat		17,070.00	17,070.00	17,070.00	17,070.00
Combined customer		285.00	285.00	285.00	285.00
Wall Insulation					
Electric heat		59,733.00	59,733.00	59,733.00	59,733.00
Combined customer		435.00	435.00	435.00	435.00
Infiltration					
Electric heat		36,747.00	36,747.00	36,747.00	36,747.00
Combined customer		386.00	386.00	386.00	386.00
Data Center Items		270.00	270.00	270.00	270.00
Data Center - thin client		270.00	270.00	270.00	270.00
CFLs - Audit		113.22	113.22	113.22	113.22
Water Heater Measures - Electric					
Aerator - electric		171.00	171.00	171.00	171.00
Pipe insulation - electric		16.00	16.00	16.00	16.00
Blanket - electric		166.00	166.00	166.00	166.00
Retrofit LED Exit sign		369.50	369.50	369.50	369.50
Vending Machine controller		1,250.00	1,250.00	1,250.00	1,250.00
Pre-rinse sprayer - elect WH (1.0 GPM)		485.00	485.00	485.00	485.00
Smart strips		100.00	100.00	100.00	100.00
Programmable thermostats					
Electric		264.00	264.00	264.00	264.00
Combined		264.00	264.00	264.00	264.00
High Vol low speed fans		8,756.25	8,756.25	8,756.25	8,756.25
Circulating Fans		251.00	251.00	251.00	251.00
C&I Appliance Recycling					
Refrigerators		844.00	844.00	844.00	844.00
Freezers		479.00	479.00	479.00	479.00
AC		244.00	244.00	244.00	244.00
Clothes Washers					
Electric		224.00	224.00	224.00	224.00
Combined		25.00	25.00	25.00	25.00
Dishwashers					
Electric		60.00	60.00	60.00	60.00
Combined		26.00	26.00	26.00	26.00
ECM Motors					
ECM Motors - OEM Large		1,300.00	1,300.00	1,300.00	1,300.00
ECM Motors - OEM Small		785.00	785.00	785.00	785.00
ECM Motors - Replacement Large		1,300.00	1,300.00	1,300.00	1,300.00
ECM Motors - Replacement Small		785.00	785.00	785.00	785.00
Variable Frequency Drives		47,198.13	47,198.13	47,198.13	47,198.13
Motors - Replace on Failure & New Construction		194.80	194.80	194.80	194.80

		Per Measure Annual Energy Savings (KWh) 2015			
		Base	**High**	**Medium**	**Min. Spend**
8. Commercial New Construction		350,000.00	350,000.00	350,000.00	350,000.00
9. Small Business Direct Install		555,000.00	555,000.00	555,000.00	555,000.00
10. Agricultural					
Lighting					
Infrared Brooder Lamps		126.00	126.00	126.00	126.00
CFLs		138.75	138.75	138.75	138.75
Light Fixtures 100W-26W		122.10	122.10	122.10	122.10
T-8 Fluorescent Fixtures with electronic ballasts		277.05	277.05	277.05	277.05
High Performance T8		48.58	48.58	48.58	48.58
T-5 Fluorescent Fixtures with electronic ballasts		226.91	226.91	226.91	226.91
High Bay Fluorescent Fixtures above 15 ft		1,474.05	1,474.05	1,474.05	1,474.05
Pulse Start Metal halide (<250 watts in old plan)		2,135.36	2,135.36	2,135.36	2,135.36
Metal Halide Replacement Lamp, 360 Watt to replace 400 watt		199.80	199.80	199.80	199.80
LED exit sign		204.24	204.24	204.24	204.24
Occupancy sensors		315.46	315.46	315.46	315.46
LEDs - bulbs - interior standard		98.79	98.79	98.79	98.79
LEDs - interior specialty		166.50	166.50	166.50	166.50
LEDs - exterior		51.00	51.00	51.00	51.00
LED desklamp		101.01	101.01	101.01	101.01
Ventilation measures					
Fans controlled by thermostat		2,675.52	2,675.52	2,675.52	2,675.52
Fans uncontrolled		1,446.75	1,446.75	1,446.75	1,446.75
Fan controls		1,402.50	1,402.50	1,402.50	1,402.50
HVLS fans		11,080.57	11,080.57	11,080.57	11,080.57
Circulating Fans		251.00	251.00	251.00	251.00
Dairy Measures					
Automatic milker takeoff ($5 per cow)		67.00	67.00	67.00	67.00
Milk precooler ($3.40 per cow)		42.00	42.00	42.00	42.00
VSD vacuum pump ($5 per cow)		60.00	60.00	60.00	60.00
Scroll compressor (per ton)		2,227.00	2,227.00	2,227.00	2,227.00
Other farm measures					
Livestock waterer		544.00	544.00	544.00	544.00
Tractor heater timer		810.00	810.00	810.00	810.00
Refrigerators		83.00	83.00	83.00	83.00
Freezers		42.00	42.00	42.00	42.00
11. Shared Savings		4,800,000.00	4,800,000.00	4,800,000.00	4,800,000.00
12. Direct Load Cotrol					
AC		4.13	4.13	4.13	4.13
Water Heat		0.00	0.00	0.00	0.00

2014 IRP Base Scenario - Plan Impacts and Costs

	Plan Impacts			Plan Costs		
Year	Energy (KWh)	Peak Demand (KW)	Year	Incentives ($)	Admin ($)	Total ($)
2014	11,816,508	2,550	2014	1,604,002	1,264,493	2,868,495
2015	23,623,877	5,900	2015	1,661,512	1,358,102	3,019,614
2016	35,374,128	8,700	2016	1,717,392	994,188	2,711,580
2017	47,053,251	10,694	2017	1,751,740	1,014,072	2,765,812
2018	58,743,592	12,690	2018	1,786,775	1,034,353	2,821,128
2019	70,308,441	14,627	2019	1,822,510	1,055,040	2,877,550
2020	81,664,267	16,549	2020	1,858,960	1,076,141	2,935,101
2021	92,690,002	18,437	2021	1,896,140	1,097,664	2,993,803
2022	102,911,784	20,203	2022	1,934,062	1,119,617	3,053,679
2023	112,393,910	21,942	2023	1,972,744	1,142,010	3,114,753
2024	121,301,341	23,557	2024	2,012,198	1,164,850	3,177,048
2025	130,059,303	25,154	2025	2,052,442	1,188,147	3,240,589
2026	138,761,952	26,742	2026	2,093,491	1,211,910	3,305,401
2027	147,460,350	28,330	2027	2,135,361	1,236,148	3,371,509
2028	155,666,566	29,727	2028	2,178,069	1,260,871	3,438,940
2029	157,196,980	29,931	2029	2,221,630	1,286,088	3,507,719
Edge Effects						
2030	157,196,980	29,931	2030	2,266,063	1,311,810	3,577,873
2031	157,196,980	29,931	2031	2,311,384	1,338,046	3,649,430
2032	157,196,980	29,931	2032	2,357,612	1,364,807	3,722,419
2033	157,196,980	29,931	2033	2,404,764	1,392,103	3,796,867
2034	157,196,980	29,931	2034	2,452,859	1,419,945	3,872,805
2035	157,196,980	29,931	2035	2,501,917	1,448,344	3,950,261
2036	157,196,980	29,931	2036	2,551,955	1,477,311	4,029,266
2037	157,196,980	29,931	2037	2,602,994	1,506,857	4,109,851
2038	157,196,980	29,931	2038	2,655,054	1,536,994	4,192,048
2039	157,196,980	29,931	2039	2,708,155	1,567,734	4,275,889
2040	157,196,980	29,931	2040	2,762,318	1,599,089	4,361,407
2041	157,196,980	29,931	2041	2,817,564	1,631,071	4,448,635
2042	157,196,980	29,931	2042	2,873,916	1,663,692	4,537,608
2043	157,196,980	29,931	2043	2,931,394	1,696,966	4,628,360
2044	157,196,980	29,931	2044	2,990,022	1,730,905	4,720,927
2045	157,196,980	29,931	2045	3,049,822	1,765,523	4,815,346
2046	157,196,980	29,931	2046	3,110,819	1,800,834	4,911,653
2047	157,196,980	29,931	2047	3,173,035	1,836,851	5,009,886
2048	157,196,980	29,931	2048	3,236,496	1,873,588	5,110,084
2049	157,196,980	29,931	2049	3,301,226	1,911,059	5,212,285
2050	157,196,980	29,931	2050	3,367,250	1,949,281	5,316,531
2051	157,196,980	29,931	2051	3,434,595	1,988,266	5,422,862
2052	157,196,980	29,931	2052	3,503,287	2,028,032	5,531,319
2053	157,196,980	29,931	2053	3,573,353	2,068,592	5,641,945
2054	157,196,980	29,931	2054	3,644,820	2,109,964	5,754,784
2055	157,196,980	29,931	2055	3,717,717	2,152,163	5,869,880
2056	157,196,980	29,931	2056	3,792,071	2,195,207	5,987,277
2057	157,196,980	29,931	2057	3,867,912	2,239,111	6,107,023
2058	157,196,980	29,931	2058	3,945,271	2,283,893	6,229,163
2059	157,196,980	29,931	2059	4,024,176	2,329,571	6,353,747
2060	157,196,980	29,931	2060	4,104,659	2,376,162	6,480,822
2061	157,196,980	29,931	2061	4,186,753	2,423,685	6,610,438
2062	157,196,980	29,931	2062	4,270,488	2,472,159	6,742,647
2063	157,196,980	29,931	2063	4,355,897	2,521,602	6,877,500
2064	157,196,980	29,931	2064	4,443,015	2,572,034	7,015,050

Savings are at the generator

2014 IRP Minimum Spending Scenario - Plan Impacts and Costs

	Plan Impacts			Plan Costs		
Year	Energy (KWh)	Peak Demand (KW)	Year	Incentives ($)	Admin ($)	Total ($)
2014	11,816,508	2,550	2014	1,604,002	1,264,493	2,868,495
2015	17,739,830	4,893	2015	581,608	1,020,330	1,601,938
2016	23,606,034	6,687	2016	615,890	649,659	1,265,549
2017	29,423,250	7,679	2017	628,208	662,652	1,290,860
2018	35,281,797	8,681	2018	640,772	675,905	1,316,677
2019	41,014,851	9,623	2019	653,587	689,423	1,343,011
2020	46,601,822	10,582	2020	666,659	703,212	1,369,871
2021	51,961,656	11,512	2021	679,992	717,276	1,397,268
2022	56,680,359	12,336	2022	693,592	731,622	1,425,214
2023	61,101,227	13,202	2023	707,464	746,254	1,453,718
2024	65,233,764	13,949	2024	721,613	761,179	1,482,792
2025	69,542,366	14,741	2025	736,046	776,403	1,512,448
2026	73,870,391	15,533	2026	750,766	791,931	1,542,697
2027	78,221,820	16,329	2027	765,782	807,769	1,573,551
2028	82,083,016	16,935	2028	781,097	823,925	1,605,022
2029	79,514,347	16,444	2029	796,719	840,403	1,637,123
Edge Effects						
2030	79,514,347	16,444	2030	812,654	857,211	1,669,865
2031	79,514,347	16,444	2031	828,907	874,355	1,703,262
2032	79,514,347	16,444	2032	845,485	891,843	1,737,328
2033	79,514,347	16,444	2033	862,395	909,679	1,772,074
2034	79,514,347	16,444	2034	879,643	927,873	1,807,516
2035	79,514,347	16,444	2035	897,235	946,430	1,843,666
2036	79,514,347	16,444	2036	915,180	965,359	1,880,539
2037	79,514,347	16,444	2037	933,484	984,666	1,918,150
2038	79,514,347	16,444	2038	952,153	1,004,360	1,956,513
2039	79,514,347	16,444	2039	971,196	1,024,447	1,995,643
2040	79,514,347	16,444	2040	990,620	1,044,936	2,035,556
2041	79,514,347	16,444	2041	1,010,433	1,065,834	2,076,267
2042	79,514,347	16,444	2042	1,030,641	1,087,151	2,117,793
2043	79,514,347	16,444	2043	1,051,254	1,108,894	2,160,148
2044	79,514,347	16,444	2044	1,072,279	1,131,072	2,203,351
2045	79,514,347	16,444	2045	1,093,725	1,153,693	2,247,418
2046	79,514,347	16,444	2046	1,115,599	1,176,767	2,292,367
2047	79,514,347	16,444	2047	1,137,911	1,200,303	2,338,214
2048	79,514,347	16,444	2048	1,160,670	1,224,309	2,384,978
2049	79,514,347	16,444	2049	1,183,883	1,248,795	2,432,678
2050	79,514,347	16,444	2050	1,207,561	1,273,771	2,481,332
2051	79,514,347	16,444	2051	1,231,712	1,299,246	2,530,958
2052	79,514,347	16,444	2052	1,256,346	1,325,231	2,581,577
2053	79,514,347	16,444	2053	1,281,473	1,351,736	2,633,209
2054	79,514,347	16,444	2054	1,307,103	1,378,771	2,685,873
2055	79,514,347	16,444	2055	1,333,245	1,406,346	2,739,591
2056	79,514,347	16,444	2056	1,359,910	1,434,473	2,794,382
2057	79,514,347	16,444	2057	1,387,108	1,463,162	2,850,270
2058	79,514,347	16,444	2058	1,414,850	1,492,426	2,907,275
2059	79,514,347	16,444	2059	1,443,147	1,522,274	2,965,421
2060	79,514,347	16,444	2060	1,472,010	1,552,720	3,024,729
2061	79,514,347	16,444	2061	1,501,450	1,583,774	3,085,224
2062	79,514,347	16,444	2062	1,531,479	1,615,449	3,146,928
2063	79,514,347	16,444	2063	1,562,109	1,647,758	3,209,867
2064	79,514,347	16,444	2064	1,593,351	1,680,714	3,274,064

Savings are at the generator

2014 IRP Medium Scenario - Plan Impacts and Costs

	Plan Impacts				Plan Costs		
Year	Energy (KWh)	Peak Demand (KW)		Year	Incentives ($)	Admin ($)	Total ($)
2014	11,816,508	2,550		2014	1,604,002	1,264,493	2,868,495
2015	27,154,305	6,504		2015	3,685,220	2,419,671	6,104,891
2016	42,434,985	9,907		2016	3,781,574	2,076,989	5,858,563
2017	57,631,251	12,502		2017	3,857,205	2,118,529	5,975,734
2018	72,820,669	15,096		2018	3,934,350	2,160,899	6,095,249
2019	87,884,594	17,630		2019	4,013,037	2,204,117	6,217,154
2020	102,701,734	20,130		2020	4,093,297	2,248,200	6,341,497
2021	117,127,009	22,592		2021	4,175,163	2,293,164	6,468,327
2022	130,650,639	24,923		2022	4,258,667	2,339,027	6,597,693
2023	143,169,519	27,187		2023	4,343,840	2,385,807	6,729,647
2024	154,941,888	29,323		2024	4,430,717	2,433,524	6,864,240
2025	166,369,465	31,402		2025	4,519,331	2,482,194	7,001,525
2026	177,696,888	33,467		2026	4,609,718	2,531,838	7,141,556
2027	189,003,467	35,530		2027	4,701,912	2,582,475	7,284,387
2028	199,816,695	37,402		2028	4,795,950	2,634,124	7,430,074
2029	203,806,599	38,024		2029	4,891,869	2,686,807	7,578,676
			Edge Effects				
2030	203,806,599	38,024		2030	4,989,707	2,740,543	7,730,249
2031	203,806,599	38,024		2031	5,089,501	2,795,354	7,884,854
2032	203,806,599	38,024		2032	5,191,291	2,851,261	8,042,552
2033	203,806,599	38,024		2033	5,295,117	2,908,286	8,203,403
2034	203,806,599	38,024		2034	5,401,019	2,966,452	8,367,471
2035	203,806,599	38,024		2035	5,509,039	3,025,781	8,534,820
2036	203,806,599	38,024		2036	5,619,220	3,086,296	8,705,516
2037	203,806,599	38,024		2037	5,731,604	3,148,022	8,879,627
2038	203,806,599	38,024		2038	5,846,237	3,210,983	9,057,219
2039	203,806,599	38,024		2039	5,963,161	3,275,202	9,238,364
2040	203,806,599	38,024		2040	6,082,424	3,340,706	9,423,131
2041	203,806,599	38,024		2041	6,204,073	3,407,521	9,611,594
2042	203,806,599	38,024		2042	6,328,154	3,475,671	9,803,825
2043	203,806,599	38,024		2043	6,454,718	3,545,184	9,999,902
2044	203,806,599	38,024		2044	6,583,812	3,616,088	10,199,900
2045	203,806,599	38,024		2045	6,715,488	3,688,410	10,403,898
2046	203,806,599	38,024		2046	6,849,798	3,762,178	10,611,976
2047	203,806,599	38,024		2047	6,986,794	3,837,422	10,824,215
2048	203,806,599	38,024		2048	7,126,530	3,914,170	11,040,700
2049	203,806,599	38,024		2049	7,269,060	3,992,453	11,261,514
2050	203,806,599	38,024		2050	7,414,442	4,072,303	11,486,744
2051	203,806,599	38,024		2051	7,562,730	4,153,749	11,716,479
2052	203,806,599	38,024		2052	7,713,985	4,236,824	11,950,809
2053	203,806,599	38,024		2053	7,868,265	4,321,560	12,189,825
2054	203,806,599	38,024		2054	8,025,630	4,407,991	12,433,621
2055	203,806,599	38,024		2055	8,186,143	4,496,151	12,682,294
2056	203,806,599	38,024		2056	8,349,865	4,586,074	12,935,939
2057	203,806,599	38,024		2057	8,516,863	4,677,796	13,194,658
2058	203,806,599	38,024		2058	8,687,200	4,771,351	13,458,551
2059	203,806,599	38,024		2059	8,860,944	4,866,779	13,727,722
2060	203,806,599	38,024		2060	9,038,163	4,964,114	14,002,277
2061	203,806,599	38,024		2061	9,218,926	5,063,396	14,282,322
2062	203,806,599	38,024		2062	9,403,305	5,164,664	14,567,969
2063	203,806,599	38,024		2063	9,591,371	5,267,958	14,859,328
2064	203,806,599	38,024		2064	9,783,198	5,373,317	15,156,515

Savings are at the generator

2014 IRP High Scenario - Plan Impacts and Costs

	Plan Impacts			Plan Costs		
Year	Energy (KWh)	Peak Demand (KW)	Year	Incentives ($)	Admin ($)	Total ($)
2014	11,816,508	2,550	2014	1,604,002	1,264,493	2,868,495
2015	35,391,971	7,912	2015	6,717,545	6,858,961	13,576,506
2016	58,910,317	12,725	2016	6,874,546	6,605,064	13,479,610
2017	82,313,252	16,722	2017	7,012,037	6,737,165	13,749,202
2018	105,667,182	20,709	2018	7,152,278	6,871,909	14,024,186
2019	128,895,620	24,636	2019	7,295,323	7,009,347	14,304,670
2020	151,789,156	28,484	2020	7,441,230	7,149,534	14,590,763
2021	174,146,694	32,288	2021	7,590,054	7,292,524	14,882,579
2022	195,374,635	35,936	2022	7,741,855	7,438,375	15,180,230
2023	214,979,274	39,423	2023	7,896,692	7,587,142	15,483,835
2024	233,436,496	42,774	2024	8,054,626	7,738,885	15,793,512
2025	251,093,176	45,981	2025	8,215,719	7,893,663	16,109,382
2026	268,545,074	49,160	2026	8,380,033	8,051,536	16,431,569
2027	285,937,408	52,330	2027	8,547,634	8,212,567	16,760,201
2028	302,833,664	55,310	2028	8,718,587	8,376,818	17,095,405
2029	312,562,245	56,907	2029	8,892,958	8,544,355	17,437,313
			Edge Effects			
2030	312,562,245	56,907	2030	9,070,817	8,715,242	17,786,059
2031	312,562,245	56,907	2031	9,252,234	8,889,547	18,141,780
2032	312,562,245	56,907	2032	9,437,278	9,067,337	18,504,616
2033	312,562,245	56,907	2033	9,626,024	9,248,684	18,874,708
2034	312,562,245	56,907	2034	9,818,545	9,433,658	19,252,202
2035	312,562,245	56,907	2035	10,014,915	9,622,331	19,637,246
2036	312,562,245	56,907	2036	10,215,214	9,814,778	20,029,991
2037	312,562,245	56,907	2037	10,419,518	10,011,073	20,430,591
2038	312,562,245	56,907	2038	10,627,908	10,211,295	20,839,203
2039	312,562,245	56,907	2039	10,840,467	10,415,521	21,255,987
2040	312,562,245	56,907	2040	11,057,276	10,623,831	21,681,107
2041	312,562,245	56,907	2041	11,278,421	10,836,308	22,114,729
2042	312,562,245	56,907	2042	11,503,990	11,053,034	22,557,024
2043	312,562,245	56,907	2043	11,734,070	11,274,094	23,008,164
2044	312,562,245	56,907	2044	11,968,751	11,499,576	23,468,327
2045	312,562,245	56,907	2045	12,208,126	11,729,568	23,937,694
2046	312,562,245	56,907	2046	12,452,289	11,964,159	24,416,448
2047	312,562,245	56,907	2047	12,701,334	12,203,442	24,904,777
2048	312,562,245	56,907	2048	12,955,361	12,447,511	25,402,872
2049	312,562,245	56,907	2049	13,214,468	12,696,461	25,910,930
2050	312,562,245	56,907	2050	13,478,758	12,950,391	26,429,148
2051	312,562,245	56,907	2051	13,748,333	13,209,398	26,957,731
2052	312,562,245	56,907	2052	14,023,299	13,473,586	27,496,886
2053	312,562,245	56,907	2053	14,303,765	13,743,058	28,046,824
2054	312,562,245	56,907	2054	14,589,841	14,017,919	28,607,760
2055	312,562,245	56,907	2055	14,881,637	14,298,278	29,179,915
2056	312,562,245	56,907	2056	15,179,270	14,584,243	29,763,514
2057	312,562,245	56,907	2057	15,482,856	14,875,928	30,358,784
2058	312,562,245	56,907	2058	15,792,513	15,173,447	30,965,959
2059	312,562,245	56,907	2059	16,108,363	15,476,916	31,585,279
2060	312,562,245	56,907	2060	16,430,530	15,786,454	32,216,984
2061	312,562,245	56,907	2061	16,759,141	16,102,183	32,861,324
2062	312,562,245	56,907	2062	17,094,324	16,424,227	33,518,550
2063	312,562,245	56,907	2063	17,436,210	16,752,711	34,188,921
2064	312,562,245	56,907	2064	17,784,934	17,087,765	34,872,700

Savings are at the generator

Benefit/Cost Results - 2014 IRP Base Scenario
No Carbon Case

	2014 Dollars			
Test Perspective	**Lifetime Benefits**	**Lifetime Costs**	**Net Benefits**	**B/C Ratio**
Residential Prescriptive Rebates				
Societal	$23,065,463	$11,224,826	$11,840,637	2.05
Utility Cost	$11,266,367	$4,908,466	$6,357,901	2.30
Ratepayer Impact Measure	$11,266,367	$14,721,641	($3,455,274)	0.77
Participant	$24,620,865	$8,360,222	$16,260,643	2.95
Residential Home Energy Assessment				
Societal	$4,467,803	$1,166,771	$3,301,032	3.83
Utility Cost	$1,370,560	$425,345	$945,215	3.22
Ratepayer Impact Measure	$1,370,560	$1,119,481	$251,079	1.22
Participant	$4,561,597	$1,126,986	$3,434,611	4.05
Residential New Construction				
Societal	$3,392,684	$1,390,136	$2,002,548	2.44
Utility Cost	$629,982	$285,520	$344,462	2.21
Ratepayer Impact Measure	$629,982	$779,369	($149,387)	0.81
Participant	$4,267,789	$1,284,986	$2,982,803	3.32
Appliance Recycling				
Societal	$8,440,430	$1,601,889	$6,838,541	5.27
Utility Cost	$5,715,759	$896,704	$4,819,055	6.37
Ratepayer Impact Measure	$5,715,759	$7,057,413	($1,341,654)	0.81
Participant	$9,915,462	$1,263,706	$8,651,756	7.85
Livingwise				
Societal	$3,220,356	$1,614,660	$1,605,696	1.99
Utility Cost	$2,198,218	$1,154,477	$1,043,741	1.90
Ratepayer Impact Measure	$2,198,218	$4,316,779	($2,118,561)	0.51
Participant	$6,008,479	$1,527,744	$4,480,735	3.93
Low Income				
Societal	$918,390	$922,852	($4,462)	1.00
Utility Cost	$322,834	$558,218	($235,384)	0.58
Ratepayer Impact Measure	$322,834	$804,396	($481,562)	0.40
Participant	$1,565,789	$786,016	$779,773	1.99
Nonresidential Prescriptive Rebates				
Societal	$27,825,567	$11,148,425	$16,677,142	2.50
Utility Cost	$15,200,676	$4,616,408	$10,584,268	3.29
Ratepayer Impact Measure	$15,200,676	$22,245,744	($7,045,068)	0.68
Participant	$22,558,780	$6,733,501	$15,825,279	3.35
Commercial New Construction				
Societal	$7,337,551	$4,548,068	$2,789,483	1.61
Utility Cost	$4,207,463	$1,719,667	$2,487,796	2.45
Ratepayer Impact Measure	$4,207,463	$5,255,255	($1,047,792)	0.80
Participant	$4,930,213	$2,781,942	$2,148,271	1.77
Small Business Direct Install				
Societal	$12,038,949	$3,871,000	$8,167,949	3.11
Utility Cost	$7,223,423	$1,560,844	$5,662,579	4.63
Ratepayer Impact Measure	$7,223,423	$7,151,520	$71,903	1.01
Participant	$6,357,406	$2,129,036	$4,228,370	2.99
Agricultural Project				
Societal	$20,869,146	$5,535,569	$15,333,577	3.77
Utility Cost	$12,046,527	$1,809,085	$10,237,442	6.66
Ratepayer Impact Measure	$12,046,527	$14,599,545	($2,553,018)	0.83
Participant	$13,588,085	$3,114,857	$10,473,228	4.36
C/I Shared Savings				
Societal	$79,105,682	$21,754,728	$57,350,954	3.64
Utility Cost	$47,436,820	$10,086,665	$37,350,155	4.70
Ratepayer Impact Measure	$47,436,820	$58,722,222	($11,285,402)	0.81
Participant	$55,207,531	$13,250,095	$41,957,436	4.17
Direct Load Control				
Societal	$8,031,554	$660,602	$7,370,952	12.16
Utility Cost	$5,885,702	$1,709,848	$4,175,854	3.44
Ratepayer Impact Measure	$5,885,702	$1,731,494	$4,154,208	3.40
Participant	$1,474,085	$0	$1,474,085	inf
All Programs				
Societal	$198,713,575	$65,439,526	$133,274,049	3.04
Utility Cost	$113,504,331	$29,731,247	$83,773,084	3.82
Ratepayer Impact Measure	$113,504,331	$138,504,859	($25,000,528)	0.82
Participant	$155,056,081	$42,359,091	$112,696,990	3.66

Benefit/Cost Results - 2014 IRP Base Scenario
Carbon Case

	2014 Dollars			
Test Perspective	**Lifetime Benefits**	**Lifetime Costs**	**Net Benefits**	**B/C Ratio**
Residential Prescriptive Rebates				
Societal	$25,115,187	$11,224,826	$13,890,361	2.24
Utility Cost	$12,485,828	$4,908,466	$7,577,362	2.54
Ratepayer Impact Measure	$12,485,828	$15,782,837	($3,297,009)	0.79
Participant	$26,363,422	$8,360,222	$18,003,200	3.15
Residential Home Energy Assessment				
Societal	$4,595,383	$1,166,771	$3,428,612	3.94
Utility Cost	$1,445,972	$425,345	$1,020,627	3.40
Ratepayer Impact Measure	$1,445,972	$1,183,524	$262,448	1.22
Participant	$4,666,838	$1,126,986	$3,539,852	4.14
Residential New Construction				
Societal	$3,491,557	$1,390,136	$2,101,421	2.51
Utility Cost	$688,089	$285,520	$402,569	2.41
Ratepayer Impact Measure	$688,089	$828,931	($140,842)	0.83
Participant	$4,350,307	$1,284,986	$3,065,321	3.39
Appliance Recycling				
Societal	$9,532,575	$1,601,889	$7,930,686	5.95
Utility Cost	$6,434,030	$896,704	$5,537,326	7.18
Ratepayer Impact Measure	$6,434,030	$7,709,811	($1,275,781)	0.83
Participant	$10,886,579	$1,263,706	$9,622,873	8.61
Livingwise				
Societal	$3,801,403	$1,614,240	$2,187,163	2.35
Utility Cost	$2,584,095	$1,154,477	$1,429,618	2.24
Ratepayer Impact Measure	$2,584,095	$4,668,390	($2,084,295)	0.55
Participant	$6,527,878	$1,527,744	$5,000,134	4.27
Low Income				
Societal	$964,145	$922,852	$41,293	1.04
Utility Cost	$351,004	$558,218	($207,214)	0.63
Ratepayer Impact Measure	$351,004	$829,108	($478,104)	0.42
Participant	$1,604,890	$786,016	$818,874	2.04
Nonresidential Prescriptive Rebates				
Societal	$32,234,536	$11,148,425	$21,086,111	2.89
Utility Cost	$17,779,777	$4,616,408	$13,163,369	3.85
Ratepayer Impact Measure	$17,779,777	$24,466,072	($6,686,295)	0.73
Participant	$24,779,108	$6,733,501	$18,045,607	3.68
Commercial New Construction				
Societal	$8,192,642	$4,548,068	$3,644,574	1.80
Utility Cost	$4,710,630	$1,719,667	$2,990,963	2.74
Ratepayer Impact Measure	$4,710,630	$5,686,503	($975,873)	0.83
Participant	$5,361,462	$2,781,942	$2,579,520	1.93
Small Business Direct Install				
Societal	$13,404,637	$3,870,442	$9,534,195	3.46
Utility Cost	$8,027,438	$1,560,844	$6,466,594	5.14
Ratepayer Impact Measure	$8,027,438	$7,835,357	$192,081	1.02
Participant	$7,041,243	$2,129,036	$4,912,207	3.31
Agricultural Project				
Societal	$23,437,871	$5,534,623	$17,903,248	4.23
Utility Cost	$13,495,154	$1,809,085	$11,686,069	7.46
Ratepayer Impact Measure	$13,495,154	$15,829,526	($2,334,372)	0.85
Participant	$14,818,066	$3,114,857	$11,703,209	4.76
C/I Shared Savings				
Societal	$90,756,520	$21,754,728	$69,001,792	4.17
Utility Cost	$54,290,233	$10,086,665	$44,203,568	5.38
Ratepayer Impact Measure	$54,290,233	$64,636,487	($10,346,254)	0.84
Participant	$61,121,786	$13,250,095	$47,871,691	4.61
Direct Load Control				
Societal	$8,033,682	$660,602	$7,373,080	12.16
Utility Cost	$5,887,155	$1,709,848	$4,177,307	3.44
Ratepayer Impact Measure	$5,887,155	$1,733,065	$4,154,090	3.40
Participant	$1,476,273	$0	$1,476,273	inf
All Programs				
Societal	$223,560,138	$65,437,602	$158,122,536	3.42
Utility Cost	$128,179,405	$29,731,247	$98,448,158	4.31
Ratepayer Impact Measure	$128,179,405	$151,189,611	($23,010,206)	0.85
Participant	$168,997,852	$42,359,091	$126,638,761	3.99

Benefit/Cost Results - 2014 IRP Minimum Spending Scenario
No Carbon Case

Test Perspective	2014 Dollars Lifetime Benefits	Lifetime Costs	Net Benefits	B/C Ratio
Residential Prescriptive Rebates				
Societal	$12,287,145	$6,324,051	$5,963,094	1.94
Utility Cost	$6,113,206	$2,488,532	$3,624,674	2.46
Ratepayer Impact Measure	$6,113,206	$7,849,456	($1,736,250)	0.78
Participant	$12,452,293	$4,391,499	$8,060,794	2.84
Residential Home Energy Assessment				
Societal	$2,372,786	$630,067	$1,742,719	3.77
Utility Cost	$742,391	$164,540	$577,851	4.51
Ratepayer Impact Measure	$742,391	$543,062	$199,329	1.37
Participant	$2,262,516	$603,227	$1,659,289	3.75
Residential New Construction				
Societal	$1,799,669	$758,266	$1,041,403	2.37
Utility Cost	$341,264	$129,680	$211,584	2.63
Ratepayer Impact Measure	$341,264	$398,463	($57,199)	0.86
Participant	$2,142,724	$687,330	$1,455,394	3.12
Appliance Recycling				
Societal	$4,458,416	$900,676	$3,557,740	4.95
Utility Cost	$3,065,862	$405,857	$2,660,005	7.55
Ratepayer Impact Measure	$3,065,862	$3,734,174	($668,312)	0.82
Participant	$5,111,623	$672,528	$4,439,095	7.60
Livingwise				
Societal	$1,709,353	$879,035	$830,318	1.94
Utility Cost	$1,186,465	$447,644	$738,821	2.65
Ratepayer Impact Measure	$1,186,465	$2,167,454	($980,989)	0.55
Participant	$2,951,926	$816,754	$2,135,172	3.61
Low Income				
Societal	$918,390	$922,852	($4,462)	1.00
Utility Cost	$322,834	$558,218	($235,384)	0.58
Ratepayer Impact Measure	$322,834	$804,396	($481,562)	0.40
Participant	$1,565,789	$786,016	$779,773	1.99
Nonresidential Prescriptive Rebates				
Societal	$14,812,658	$6,303,088	$8,509,570	2.35
Utility Cost	$8,234,750	$2,271,609	$5,963,141	3.63
Ratepayer Impact Measure	$8,234,750	$11,866,791	($3,632,041)	0.69
Participant	$11,701,519	$3,674,186	$8,027,333	3.18
Commercial New Construction				
Societal	$3,906,495	$2,563,780	$1,342,715	1.52
Utility Cost	$2,279,484	$855,721	$1,423,763	2.66
Ratepayer Impact Measure	$2,279,484	$2,780,001	($500,517)	0.82
Participant	$2,470,711	$1,516,945	$953,766	1.63
Small Business Direct Install				
Societal	$6,410,463	$2,209,966	$4,200,497	2.90
Utility Cost	$3,912,985	$820,568	$3,092,417	4.77
Ratepayer Impact Measure	$3,912,985	$3,863,351	$49,634	1.01
Participant	$3,321,802	$1,157,096	$2,164,706	2.87
Agricultural Project				
Societal	$11,116,296	$3,138,888	$7,977,408	3.54
Utility Cost	$6,528,010	$980,031	$5,547,979	6.66
Ratepayer Impact Measure	$6,528,010	$7,942,563	($1,414,553)	0.82
Participant	$7,252,794	$1,694,473	$5,558,321	4.28
C/I Shared Savings				
Societal	$42,131,669	$12,273,595	$29,858,074	3.43
Utility Cost	$25,705,204	$4,788,448	$20,916,756	5.37
Ratepayer Impact Measure	$25,705,204	$31,258,853	($5,553,649)	0.82
Participant	$28,861,997	$7,225,047	$21,636,950	3.99
Direct Load Control				
Societal	$8,031,554	$660,602	$7,370,952	12.16
Utility Cost	$5,885,702	$1,709,848	$4,175,854	3.44
Ratepayer Impact Measure	$5,885,702	$1,731,494	$4,154,208	3.40
Participant	$1,474,085	$0	$1,474,085	inf
All Programs				
Societal	$109,954,894	$37,564,866	$72,390,028	2.93
Utility Cost	$64,318,157	$15,620,696	$48,697,461	4.12
Ratepayer Impact Measure	$64,318,157	$74,940,058	($10,621,901)	0.86
Participant	$81,569,779	$23,225,101	$58,344,678	3.51

Benefit/Cost Results - 2014 IRP Minimum Spending Scenario
Carbon Case

Test Perspective	2014 Dollars Lifetime Benefits	Lifetime Costs	Net Benefits	B/C Ratio
Residential Prescriptive Rebates				
Societal	$13,366,869	$6,324,051	$7,042,818	2.11
Utility Cost	$6,763,338	$2,488,532	$4,274,806	2.72
Ratepayer Impact Measure	$6,763,338	$8,419,424	($1,656,086)	0.80
Participant	$13,376,101	$4,391,499	$8,984,602	3.05
Residential Home Energy Assessment				
Societal	$2,439,828	$630,067	$1,809,761	3.87
Utility Cost	$782,453	$164,540	$617,913	4.76
Ratepayer Impact Measure	$782,453	$577,318	$205,135	1.36
Participant	$2,318,144	$603,227	$1,714,917	3.84
Residential New Construction				
Societal	$1,851,764	$758,266	$1,093,498	2.44
Utility Cost	$372,255	$129,680	$242,575	2.87
Ratepayer Impact Measure	$372,255	$425,070	($52,815)	0.88
Participant	$2,186,452	$687,330	$1,499,122	3.18
Appliance Recycling				
Societal	$5,024,681	$900,676	$4,124,005	5.58
Utility Cost	$3,441,755	$405,857	$3,035,898	8.48
Ratepayer Impact Measure	$3,441,755	$4,078,517	($636,762)	0.84
Participant	$5,619,047	$672,528	$4,946,519	8.36
Livingwise				
Societal	$2,011,429	$878,790	$1,132,639	2.29
Utility Cost	$1,389,070	$447,644	$941,426	3.10
Ratepayer Impact Measure	$1,389,070	$2,353,477	($964,407)	0.59
Participant	$3,223,865	$816,754	$2,407,111	3.95
Low Income				
Societal	$964,145	$922,852	$41,293	1.04
Utility Cost	$351,004	$558,218	($207,214)	0.63
Ratepayer Impact Measure	$351,004	$829,108	($478,104)	0.42
Participant	$1,604,890	$786,016	$818,874	2.04
Nonresidential Prescriptive Rebates				
Societal	$17,135,116	$6,303,088	$10,832,028	2.72
Utility Cost	$9,609,192	$2,271,609	$7,337,583	4.23
Ratepayer Impact Measure	$9,609,192	$13,056,111	($3,446,919)	0.74
Participant	$12,890,838	$3,674,186	$9,216,652	3.51
Commercial New Construction				
Societal	$4,357,191	$2,563,780	$1,793,411	1.70
Utility Cost	$2,547,962	$855,721	$1,692,241	2.98
Ratepayer Impact Measure	$2,547,962	$3,011,513	($463,551)	0.85
Participant	$2,702,223	$1,516,945	$1,185,278	1.78
Small Business Direct Install				
Societal	$7,130,277	$2,209,640	$4,920,637	3.23
Utility Cost	$4,342,006	$820,568	$3,521,438	5.29
Ratepayer Impact Measure	$4,342,006	$4,230,463	$111,543	1.03
Participant	$3,688,914	$1,157,096	$2,531,818	3.19
Agricultural Project				
Societal	$12,471,571	$3,138,338	$9,333,233	3.97
Utility Cost	$7,301,620	$980,031	$6,321,589	7.45
Ratepayer Impact Measure	$7,301,620	$8,603,091	($1,301,471)	0.85
Participant	$7,913,322	$1,694,473	$6,218,849	4.67
C/I Shared Savings				
Societal	$48,271,942	$12,273,595	$35,998,347	3.93
Utility Cost	$29,361,590	$4,788,448	$24,573,142	6.13
Ratepayer Impact Measure	$29,361,590	$34,433,872	($5,072,282)	0.85
Participant	$32,037,016	$7,225,047	$24,811,969	4.43
Direct Load Control				
Societal	$8,033,682	$660,602	$7,373,080	12.16
Utility Cost	$5,887,155	$1,709,848	$4,177,307	3.44
Ratepayer Impact Measure	$5,887,155	$1,733,065	$4,154,090	3.40
Participant	$1,476,273	$0	$1,476,273	inf
All Programs				
Societal	$123,058,495	$37,563,745	$85,494,750	3.28
Utility Cost	$72,149,400	$15,620,696	$56,528,704	4.62
Ratepayer Impact Measure	$72,149,400	$81,751,029	($9,601,629)	0.88
Participant	$89,037,085	$23,225,101	$65,811,984	3.83

Benefit/Cost Results - 2014 IRP Medium Scenario
No Carbon Case

	2014 Dollars			
Test Perspective	**Lifetime Benefits**	**Lifetime Costs**	**Net Benefits**	**B/C Ratio**
Residential Prescriptive Rebates				
Societal	$29,532,453	$16,925,374	$12,607,079	1.74
Utility Cost	$14,358,264	$10,096,756	$4,261,508	1.42
Ratepayer Impact Measure	$14,358,264	$22,581,282	($8,223,018)	0.64
Participant	$34,591,069	$11,131,467	$23,459,602	3.11
Residential Home Energy Assessment				
Societal	$5,724,814	$1,521,713	$4,203,101	3.76
Utility Cost	$1,747,462	$723,629	$1,023,833	2.41
Ratepayer Impact Measure	$1,747,462	$1,607,134	$140,328	1.09
Participant	$6,251,704	$1,441,241	$4,810,463	4.34
Residential New Construction				
Societal	$4,348,492	$1,856,253	$2,492,239	2.34
Utility Cost	$803,212	$663,817	$139,395	1.21
Ratepayer Impact Measure	$803,212	$1,292,705	($489,493)	0.62
Participant	$6,275,402	$1,643,579	$4,631,823	3.82
Appliance Recycling				
Societal	$10,829,638	$2,302,416	$8,527,222	4.70
Utility Cost	$7,305,698	$1,731,934	$5,573,764	4.22
Ratepayer Impact Measure	$7,305,698	$9,592,078	($2,286,380)	0.76
Participant	$13,235,576	$1,618,412	$11,617,164	8.18
Livingwise				
Societal	$4,126,958	$2,148,911	$1,978,047	1.92
Utility Cost	$2,805,271	$1,532,105	$1,273,166	1.83
Ratepayer Impact Measure	$2,805,271	$5,559,903	($2,754,632)	0.50
Participant	$7,687,861	$1,954,339	$5,733,522	3.93
Low Income				
Societal	$918,390	$922,852	($4,462)	1.00
Utility Cost	$322,834	$558,218	($235,384)	0.58
Ratepayer Impact Measure	$322,834	$804,396	($481,562)	0.40
Participant	$1,565,789	$786,016	$779,773	1.99
Nonresidential Prescriptive Rebates				
Societal	$35,633,312	$16,052,319	$19,580,993	2.22
Utility Cost	$19,380,231	$9,148,893	$10,231,338	2.12
Ratepayer Impact Measure	$19,380,231	$31,598,721	($12,218,490)	0.61
Participant	$30,867,880	$8,569,091	$22,298,789	3.60
Commercial New Construction				
Societal	$9,396,185	$6,514,555	$2,881,630	1.44
Utility Cost	$5,364,259	$3,891,474	$1,472,785	1.38
Ratepayer Impact Measure	$5,364,259	$8,393,846	($3,029,587)	0.64
Participant	$7,662,617	$3,540,940	$4,121,677	2.16
Small Business Direct Install				
Societal	$15,416,041	$5,719,951	$9,696,090	2.70
Utility Cost	$9,209,686	$3,469,387	$5,740,299	2.65
Ratepayer Impact Measure	$9,209,686	$10,588,798	($1,379,112)	0.87
Participant	$9,000,910	$2,712,199	$6,288,711	3.32
Agricultural Project				
Societal	$26,720,857	$8,059,192	$18,661,665	3.32
Utility Cost	$15,357,637	$3,758,830	$11,598,807	4.09
Ratepayer Impact Measure	$15,357,637	$20,046,046	($4,688,409)	0.77
Participant	$18,023,556	$3,967,088	$14,056,468	4.54
C/I Shared Savings				
Societal	$101,290,090	$31,215,774	$70,074,316	3.24
Utility Cost	$60,475,790	$23,155,016	$37,320,774	2.61
Ratepayer Impact Measure	$60,475,790	$85,089,664	($24,613,874)	0.71
Participant	$78,061,780	$16,865,123	$61,196,657	4.63
Direct Load Control				
Societal	$8,031,554	$660,602	$7,370,952	12.16
Utility Cost	$5,885,702	$1,709,848	$4,175,854	3.44
Ratepayer Impact Measure	$5,885,702	$1,731,494	$4,154,208	3.40
Participant	$1,474,085	$0	$1,474,085	inf
All Programs				
Societal	$251,968,784	$93,899,912	$158,068,872	2.68
Utility Cost	$143,016,046	$60,439,907	$82,576,139	2.37
Ratepayer Impact Measure	$143,016,046	$198,886,067	($55,870,021)	0.72
Participant	$214,698,229	$54,229,495	$160,468,734	3.96

Benefit/Cost Results - 2014 IRP Medium Scenario
Carbon Case

	2014 Dollars			
Test Perspective	**Lifetime Benefits**	**Lifetime Costs**	**Net Benefits**	**B/C Ratio**
Residential Prescriptive Rebates				
Societal	$32,164,177	$16,925,374	$15,238,803	1.90
Utility Cost	$15,919,322	$10,096,756	$5,822,566	1.58
Ratepayer Impact Measure	$15,919,322	$23,937,216	($8,017,894)	0.67
Participant	$36,824,875	$11,131,467	$25,693,408	3.31
Residential Home Energy Assessment				
Societal	$5,888,716	$1,521,713	$4,367,003	3.87
Utility Cost	$1,844,084	$723,629	$1,120,455	2.55
Ratepayer Impact Measure	$1,844,084	$1,689,048	$155,036	1.09
Participant	$6,386,712	$1,441,241	$4,945,471	4.43
Residential New Construction				
Societal	$4,475,433	$1,856,253	$2,619,180	2.41
Utility Cost	$877,589	$663,817	$213,772	1.32
Ratepayer Impact Measure	$877,589	$1,356,041	($478,452)	0.65
Participant	$6,381,195	$1,643,579	$4,737,616	3.88
Appliance Recycling				
Societal	$12,237,311	$2,302,416	$9,934,895	5.31
Utility Cost	$8,229,395	$1,731,934	$6,497,461	4.75
Ratepayer Impact Measure	$8,229,395	$10,429,309	($2,199,914)	0.79
Participant	$14,484,909	$1,618,412	$12,866,497	8.95
Livingwise				
Societal	$4,875,388	$2,148,386	$2,727,002	2.27
Utility Cost	$3,301,109	$1,532,105	$1,769,004	2.15
Ratepayer Impact Measure	$3,301,109	$6,010,867	($2,709,758)	0.55
Participant	$8,355,736	$1,954,339	$6,401,397	4.28
Low Income				
Societal	$964,145	$922,852	$41,293	1.04
Utility Cost	$351,004	$558,218	($207,214)	0.63
Ratepayer Impact Measure	$351,004	$829,108	($478,104)	0.42
Participant	$1,604,890	$786,016	$818,874	2.04
Nonresidential Prescriptive Rebates				
Societal	$41,294,188	$16,052,319	$25,241,869	2.57
Utility Cost	$22,682,128	$9,148,893	$13,533,235	2.48
Ratepayer Impact Measure	$22,682,128	$34,437,653	($11,755,525)	0.66
Participant	$33,706,813	$8,569,091	$25,137,722	3.93
Commercial New Construction				
Societal	$10,493,913	$6,514,555	$3,979,358	1.61
Utility Cost	$6,008,232	$3,891,474	$2,116,758	1.54
Ratepayer Impact Measure	$6,008,232	$8,944,937	($2,936,705)	0.67
Participant	$8,213,707	$3,540,940	$4,672,767	2.32
Small Business Direct Install				
Societal	$17,169,253	$5,719,254	$11,449,999	3.00
Utility Cost	$10,238,696	$3,469,387	$6,769,309	2.95
Ratepayer Impact Measure	$10,238,696	$11,462,671	($1,223,975)	0.89
Participant	$9,874,783	$2,712,199	$7,162,584	3.64
Agricultural Project				
Societal	$30,017,651	$8,058,009	$21,959,642	3.73
Utility Cost	$17,211,274	$3,758,830	$13,452,444	4.58
Ratepayer Impact Measure	$17,211,274	$21,617,699	($4,406,425)	0.80
Participant	$19,595,209	$3,967,088	$15,628,121	4.94
C/I Shared Savings				
Societal	$116,247,266	$31,215,774	$85,031,492	3.72
Utility Cost	$69,247,419	$23,155,016	$46,092,403	2.99
Ratepayer Impact Measure	$69,247,419	$92,647,477	($23,400,058)	0.75
Participant	$85,619,593	$16,865,123	$68,754,470	5.08
Direct Load Control				
Societal	$8,033,682	$660,602	$7,373,080	12.16
Utility Cost	$5,887,155	$1,709,848	$4,177,307	3.44
Ratepayer Impact Measure	$5,887,155	$1,733,065	$4,154,090	3.40
Participant	$1,476,273	$0	$1,476,273	inf
All Programs				
Societal	$283,861,123	$93,897,507	$189,963,616	3.02
Utility Cost	$161,797,407	$60,439,907	$101,357,500	2.68
Ratepayer Impact Measure	$161,797,407	$215,095,091	($53,297,684)	0.75
Participant	$232,524,695	$54,229,495	$178,295,200	4.29

Benefit/Cost Results - 2014 IRP High Scenario
No Carbon Case

Test Perspective	2014 Dollars Lifetime Benefits	Lifetime Costs	Net Benefits	B/C Ratio
Residential Prescriptive Rebates				
Societal	$44,622,098	$35,257,051	$9,365,047	1.27
Utility Cost	$21,572,689	$23,336,138	($1,763,449)	0.92
Ratepayer Impact Measure	$21,572,689	$42,053,817	($20,481,128)	0.51
Participant	$53,989,147	$17,213,330	$36,775,817	3.14
Residential Home Energy Assessment				
Societal	$8,657,838	$2,425,109	$6,232,729	3.57
Utility Cost	$2,626,900	$1,209,115	$1,417,785	2.17
Ratepayer Impact Measure	$2,626,900	$2,534,479	$92,421	1.04
Participant	$9,512,963	$2,174,503	$7,338,460	4.37
Residential New Construction				
Societal	$6,578,713	$3,142,616	$3,436,097	2.09
Utility Cost	$1,207,416	$1,485,703	($278,287)	0.81
Ratepayer Impact Measure	$1,207,416	$2,429,684	($1,222,268)	0.50
Participant	$10,256,234	$2,480,296	$7,775,938	4.14
Appliance Recycling				
Societal	$16,404,458	$4,576,222	$11,828,236	3.58
Utility Cost	$11,015,555	$3,444,845	$7,570,710	3.20
Ratepayer Impact Measure	$11,015,555	$15,270,336	($4,254,781)	0.72
Participant	$20,030,116	$2,446,061	$17,584,055	8.19
Livingwise				
Societal	$6,242,362	$3,607,680	$2,634,682	1.73
Utility Cost	$4,221,726	$2,573,119	$1,648,607	1.64
Ratepayer Impact Measure	$4,221,726	$8,620,407	($4,398,681)	0.49
Participant	$11,606,420	$2,949,726	$8,656,694	3.93
Low Income				
Societal	$918,390	$922,852	($4,462)	1.00
Utility Cost	$322,834	$558,218	($235,384)	0.58
Ratepayer Impact Measure	$322,834	$804,396	($481,562)	0.40
Participant	$1,565,789	$786,016	$779,773	1.99
Nonresidential Prescriptive Rebates				
Societal	$53,851,385	$32,056,470	$21,794,915	1.68
Utility Cost	$29,132,527	$20,673,282	$8,459,245	1.41
Ratepayer Impact Measure	$29,132,527	$54,370,926	($25,238,399)	0.54
Participant	$47,406,759	$12,852,133	$34,554,626	3.69
Commercial New Construction				
Societal	$14,199,664	$12,875,724	$1,323,940	1.10
Utility Cost	$8,063,421	$9,268,243	($1,204,822)	0.87
Ratepayer Impact Measure	$8,063,421	$16,026,445	($7,963,024)	0.50
Participant	$12,831,223	$5,311,937	$7,519,286	2.42
Small Business Direct Install				
Societal	$23,295,921	$11,981,448	$11,314,473	1.94
Utility Cost	$13,844,299	$7,764,231	$6,080,068	1.78
Ratepayer Impact Measure	$13,844,299	$18,450,693	($4,606,394)	0.75
Participant	$13,543,383	$4,072,915	$9,470,468	3.33
Agricultural Project				
Societal	$40,374,848	$16,427,881	$23,946,967	2.46
Utility Cost	$23,083,561	$9,410,632	$13,672,929	2.45
Ratepayer Impact Measure	$23,083,561	$33,856,948	($10,773,387)	0.68
Participant	$27,606,522	$5,955,626	$21,650,896	4.64
C/I Shared Savings				
Societal	$153,053,708	$61,910,062	$91,143,646	2.47
Utility Cost	$90,900,053	$53,373,683	$37,526,370	1.70
Ratepayer Impact Measure	$90,900,053	$146,339,543	($55,439,490)	0.62
Participant	$124,620,124	$25,300,190	$99,319,934	4.93
Direct Load Control				
Societal	$8,031,554	$660,602	$7,370,952	12.16
Utility Cost	$5,885,702	$1,709,848	$4,175,854	3.44
Ratepayer Impact Measure	$5,885,702	$1,731,494	$4,154,208	3.40
Participant	$1,474,085	$0	$1,474,085	inf
All Programs				
Societal	$376,230,939	$185,843,717	$190,387,222	2.02
Utility Cost	$211,876,683	$134,807,057	$77,069,626	1.57
Ratepayer Impact Measure	$211,876,683	$342,489,168	($130,612,485)	0.62
Participant	$334,442,765	$81,542,733	$252,900,032	4.10

Benefit/Cost Results - 2014 IRP High Scenario
Carbon Case

Test Perspective	2014 Dollars Lifetime Benefits	Lifetime Costs	Net Benefits	B/C Ratio
Residential Prescriptive Rebates				
Societal	$48,611,822	$35,257,051	$13,354,771	1.38
Utility Cost	$23,930,807	$23,336,138	$594,669	1.03
Ratepayer Impact Measure	$23,930,807	$44,097,471	($20,166,664)	0.54
Participant	$57,369,202	$17,213,330	$40,155,872	3.33
Residential Home Energy Assessment				
Societal	$8,906,494	$2,425,109	$6,481,385	3.67
Utility Cost	$2,773,012	$1,209,115	$1,563,897	2.29
Ratepayer Impact Measure	$2,773,012	$2,658,094	$114,918	1.04
Participant	$9,717,429	$2,174,503	$7,542,926	4.47
Residential New Construction				
Societal	$6,771,143	$3,142,616	$3,628,527	2.15
Utility Cost	$1,319,757	$1,485,703	($165,946)	0.89
Ratepayer Impact Measure	$1,319,757	$2,525,158	($1,205,401)	0.52
Participant	$10,416,333	$2,480,296	$7,936,037	4.20
Appliance Recycling				
Societal	$18,548,361	$4,576,222	$13,972,139	4.05
Utility Cost	$12,418,580	$3,444,845	$8,973,735	3.60
Ratepayer Impact Measure	$12,418,580	$16,538,844	($4,120,264)	0.75
Participant	$21,928,618	$2,446,061	$19,482,557	8.96
Livingwise				
Societal	$7,381,351	$3,606,909	$3,774,442	2.05
Utility Cost	$4,974,143	$2,573,119	$2,401,024	1.93
Ratepayer Impact Measure	$4,974,143	$9,303,193	($4,329,050)	0.53
Participant	$12,620,740	$2,949,726	$9,671,014	4.28
Low Income				
Societal	$964,145	$922,852	$41,293	1.04
Utility Cost	$351,004	$558,218	($207,214)	0.63
Ratepayer Impact Measure	$351,004	$829,108	($478,104)	0.42
Participant	$1,604,890	$786,016	$818,874	2.04
Nonresidential Prescriptive Rebates				
Societal	$62,433,376	$32,056,470	$30,376,906	1.95
Utility Cost	$34,120,948	$20,673,282	$13,447,666	1.65
Ratepayer Impact Measure	$34,120,948	$58,653,269	($24,532,321)	0.58
Participant	$51,689,102	$12,852,133	$38,836,969	4.02
Commercial New Construction				
Societal	$15,863,546	$12,875,724	$2,987,822	1.23
Utility Cost	$9,035,968	$9,268,243	($232,275)	0.97
Ratepayer Impact Measure	$9,035,968	$16,857,167	($7,821,199)	0.54
Participant	$13,661,945	$5,311,937	$8,350,008	2.57
Small Business Direct Install				
Societal	$25,953,357	$11,980,426	$13,972,931	2.17
Utility Cost	$15,398,300	$7,764,231	$7,634,069	1.98
Ratepayer Impact Measure	$15,398,300	$19,767,980	($4,369,680)	0.78
Participant	$14,860,670	$4,072,915	$10,787,755	3.65
Agricultural Project				
Societal	$45,370,471	$16,426,145	$28,944,326	2.76
Utility Cost	$25,882,222	$9,410,632	$16,471,590	2.75
Ratepayer Impact Measure	$25,882,222	$36,225,835	($10,343,613)	0.71
Participant	$29,975,409	$5,955,626	$24,019,783	5.03
C/I Shared Savings				
Societal	$175,725,676	$61,910,062	$113,815,614	2.84
Utility Cost	$104,147,520	$53,373,683	$50,773,837	1.95
Ratepayer Impact Measure	$104,147,520	$157,732,302	($53,584,782)	0.66
Participant	$136,012,883	$25,300,190	$110,712,693	5.38
Direct Load Control				
Societal	$8,033,682	$660,602	$7,373,080	12.16
Utility Cost	$5,887,155	$1,709,848	$4,177,307	3.44
Ratepayer Impact Measure	$5,887,155	$1,733,065	$4,154,090	3.40
Participant	$1,476,273	$0	$1,476,273	inf
All Programs				
Societal	$424,563,424	$185,840,188	$238,723,236	2.28
Utility Cost	$240,239,416	$134,807,057	$105,432,359	1.78
Ratepayer Impact Measure	$240,239,416	$366,921,486	($126,682,070)	0.65
Participant	$361,333,494	$81,542,733	$279,790,761	4.43

IPL 2014 Resource Plan
Minnesota DSM Load Forecast Scenarios

	Base Forecast		_033 **Base DSM**			**High DSM Forecast**		_034 **High DSM**	
Year	GWH	MW	GWH	MW	Year	GWH	MW	GWH	MW
2014	16928	3121.3	12	2.6	2014	16928	3121.3	12	2.6
2015	17115	3151.7	24	5.9	2015	17103	3149.7	35	7.9
2016	17274	3179.1	35	8.7	2016	17251	3175.0	59	12.7
2017	17428	3205.7	47	10.7	2017	17393	3199.6	82	16.7
2018	17585	3232.8	59	12.7	2018	17538	3224.7	106	20.7
2019	17728	3257.6	70	14.6	2019	17669	3247.6	129	24.6
2020	17884	3284.6	82	16.5	2020	17814	3272.6	152	28.5
2021	18041	3311.8	93	18.4	2021	17960	3298.0	174	32.3
2022	18200	3339.3	103	20.2	2022	18107	3323.6	195	35.9
2023	18360	3368.8	112	21.9	2023	18258	3351.3	215	39.4
2024	18522	3398.5	121	23.6	2024	18410	3379.2	233	42.8
2025	18685	3428.4	130	25.2	2025	18564	3407.6	251	46.0
2026	18850	3458.6	139	26.7	2026	18720	3436.2	269	49.2
2027	19016	3489.1	147	28.3	2027	18878	3465.1	286	52.3
2028	19184	3519.9	156	29.7	2028	19037	3494.3	303	55.3
2029	19353	3550.9	157	29.9	2029	19198	3523.9	313	56.9

	Medium DSM Forecast		_035 **Medium DSM**			**Low DSM Forecast**		_036 **Low DSM**	
Year	GWH	MW	GWH	MW	Year	GWH	MW	GWH	MW
2014	16928	3121.3	12	2.6	2014	16928	3121.3	12	2.6
2015	17112	3151.1	27	6.5	2015	17121	3152.7	18	4.9
2016	17267	3177.9	42	9.9	2016	17286	3181.1	24	6.7
2017	17417	3203.9	58	12.5	2017	17446	3208.7	29	7.7
2018	17571	3230.3	73	15.1	2018	17608	3236.8	35	8.7
2019	17710	3254.6	88	17.6	2019	17757	3262.6	41	9.6
2020	17863	3281.0	103	20.1	2020	17919	3290.5	47	10.6
2021	18017	3307.7	117	22.6	2021	18082	3318.7	52	11.5
2022	18172	3334.6	131	24.9	2022	18246	3347.2	57	12.3
2023	18329	3363.5	143	27.2	2023	18411	3377.5	61	13.2
2024	18488	3392.7	155	29.3	2024	18578	3408.1	65	13.9
2025	18649	3422.2	166	31.4	2025	18746	3438.8	70	14.7
2026	18811	3451.9	178	33.5	2026	18915	3469.8	74	15.5
2027	18975	3481.9	189	35.5	2027	19085	3501.1	78	16.3
2028	19140	3512.2	200	37.4	2028	19257	3532.7	82	16.9
2029	19306	3542.8	204	38.0	2029	19431	3564.4	80	16.4

Noted DSM levels included in Forecast

IPL 2014 Resource Plan
Minnesota DSM Program Costs

7.44%	Base Annual $	**Base Present Worth $**	High Annual $	**High Present Worth $**	Medium Annual $	**Medium Present Worth $**	Minimum Annual $	**Low Present Worth $**
2014	2,868,495	2,669,957	2,868,495	2,669,957	2,868,495	2,669,957	2,868,495	2,669,957
2015	3,019,614	2,616,085	13,576,506	11,762,194	6,104,891	5,289,057	1,601,938	1,387,861
2016	2,711,580	2,186,618	13,479,610	10,869,957	5,858,563	4,724,345	1,265,549	1,020,539
2017	2,765,812	2,075,981	13,749,202	10,319,964	5,975,734	4,485,305	1,290,860	968,902
2018	2,821,128	1,970,941	14,024,186	9,797,799	6,095,249	4,258,359	1,316,677	919,878
2019	2,877,550	1,871,216	14,304,670	9,302,054	6,217,154	4,042,897	1,343,011	873,334
2020	2,935,101	1,776,537	14,590,763	8,831,393	6,341,497	3,838,336	1,369,871	829,146
2021	2,993,803	1,686,649	14,882,579	8,384,546	6,468,327	3,644,125	1,397,268	787,193
2022	3,053,679	1,601,308	15,180,230	7,960,308	6,597,693	3,459,742	1,425,214	747,363
2023	3,114,753	1,520,286	15,483,835	7,557,536	6,729,647	3,284,687	1,453,718	709,548
2024	3,177,048	1,443,363	15,793,512	7,175,143	6,864,240	3,118,490	1,482,792	673,647
2025	3,240,589	1,370,333	16,109,382	6,812,098	7,001,525	2,960,702	1,512,448	639,562
2026	3,305,401	1,300,997	16,431,569	6,467,423	7,141,556	2,810,898	1,542,697	607,202
2027	3,371,509	1,235,170	16,760,201	6,140,187	7,284,387	2,668,673	1,573,551	576,479
2028	3,438,940	1,172,674	17,095,405	5,829,508	7,430,074	2,533,645	1,605,022	547,310
2029	3,507,719	1,113,339	17,437,313	5,534,549	7,578,676	2,405,448	1,637,123	519,618
Extension								
2030	3,577,873	1,057,007	17,786,059	5,254,515	7,730,249	2,283,739	1,669,865	493,326
2031	3,649,430	1,003,525	18,141,780	4,988,649	7,884,854	2,168,187	1,703,262	468,365
2032	3,722,419	952,749	18,504,616	4,736,236	8,042,552	2,058,482	1,737,328	444,667
2033	3,796,867	904,542	18,874,708	4,496,594	8,203,403	1,954,328	1,772,074	422,168
2034	3,872,805	858,775	19,252,202	4,269,077	8,367,471	1,855,444	1,807,516	400,807
2035	3,950,261	815,323	19,637,246	4,053,072	8,534,820	1,761,563	1,843,666	380,527
2036	4,029,266	774,069	20,029,991	3,847,996	8,705,516	1,672,432	1,880,539	361,274
2037	4,109,851	734,903	20,430,591	3,653,297	8,879,627	1,587,811	1,918,150	342,994
2038	4,192,048	697,719	20,839,203	3,468,449	9,057,219	1,507,472	1,956,513	325,639
2039	4,275,889	662,416	21,255,987	3,292,954	9,238,364	1,431,197	1,995,643	309,163
2040	4,361,407	628,899	21,681,107	3,126,339	9,423,131	1,358,782	2,035,556	293,520
2041	4,448,635	597,079	22,114,729	2,968,154	9,611,594	1,290,031	2,076,267	278,669
2042	4,537,608	566,868	22,557,024	2,817,972	9,803,825	1,224,759	2,117,793	264,569
2043	4,628,360	538,186	23,008,164	2,675,390	9,999,902	1,162,789	2,160,148	251,182
2044	4,720,927	510,955	23,468,327	2,540,021	10,199,900	1,103,954	2,203,351	238,473
2045	4,815,346	485,102	23,937,694	2,411,503	10,403,898	1,048,097	2,247,418	226,407
2046	4,911,653	460,557	24,416,448	2,289,486	10,611,976	995,066	2,292,367	214,951
2047	5,009,886	437,254	24,904,777	2,173,644	10,824,215	944,718	2,338,214	204,075
2048	5,110,084	415,130	25,402,872	2,063,663	11,040,700	896,918	2,384,978	193,749
2049	5,212,285	394,125	25,910,930	1,959,247	11,261,514	851,536	2,432,678	183,946
2050	5,316,531	374,183	26,429,148	1,860,113	11,486,744	808,450	2,481,332	174,639
2051	5,422,862	355,251	26,957,731	1,765,996	11,716,479	767,544	2,530,958	165,803
2052	5,531,319	337,276	27,496,886	1,676,641	11,950,809	728,709	2,581,577	157,413
2053	5,641,945	320,211	28,046,824	1,591,807	12,189,825	691,838	2,633,209	149,449
2054	5,754,784	304,009	28,607,760	1,511,266	12,433,621	656,832	2,685,873	141,887
2055	5,869,880	288,627	29,179,915	1,434,799	12,682,294	623,598	2,739,591	134,708
2056	5,987,277	274,023	29,763,514	1,362,202	12,935,939	592,046	2,794,382	127,892
2057	6,107,023	260,158	30,358,784	1,293,278	13,194,658	562,090	2,850,270	121,421
2058	6,229,163	246,995	30,965,959	1,227,841	13,458,551	533,649	2,907,275	115,277
2059	6,353,747	234,497	31,585,279	1,165,715	13,727,722	506,648	2,965,421	109,445
2060	6,480,822	222,632	32,216,984	1,106,733	14,002,277	481,013	3,024,729	103,907
2061	6,610,438	211,368	32,861,324	1,050,735	14,282,322	456,675	3,085,224	98,649
2062	6,742,647	200,673	33,518,550	997,570	14,567,969	433,568	3,146,928	93,658
2063	6,877,500	190,519	34,188,921	947,096	14,859,328	411,631	3,209,867	88,919
2064	7,015,050	180,880	34,872,700	899,175	15,156,515	390,803	3,274,064	84,420
Cumulative		**45,107,935**		**212,391,842**		**93,997,061**		**22,643,496**

IPL 2014 Resource Plan
Minnesota DSM Scenario Summary

	a033	a034	a035	a036
No Carbon:	Base	High	Medium	Low
DSM costs with extension period	45.108	212.392	93.997	22.643
EGEAS costs with extension period	15220.018	15083.595	15194.026	15262.281
Total costs with extension period	15265.126	15295.987	15288.023	15284.924
Difference from Base	0.000	30.861	22.897	19.799

	c033	c034	c035	c036
MN Midpoint 2017 Carbon:	Base	High	Medium	Low
DSM costs with extension period	45.108	212.392	93.997	22.643
EGEAS costs with extension period	17636.656	17483.457	17605.984	17687.744
Total costs with extension period	17681.764	17695.849	17699.981	17710.387
Difference from Base	0.000	14.085	18.217	28.624

Costs are in millions of dollars discounted to 2013.

DISTRIBUTED GENERATION

This section of the IRP covers the potential impacts of future Distributed Generation (DG). A consulting service was used to provide Base, Low and High DG forecasts based on varying policies. While many DG technologies have shown significant individual growth, the aggregate energy supply remains relatively small compared to total IPL load and IPL's bandwidth for the Low Load Forecast

4.0 Distributed Generation[1] Potential

Over the last decade, electric utilities around the United States (U.S.) have experienced substantial changes to the market for distributed electric generation. Significant volumes of DG have been installed in response to equipment price declines, increased customer awareness and interest in DG, standardized market transactions and the availability of a variety of financial incentives (e.g., federal and state tax credits and exemptions, low-interest loans, grants and rebates). In 2001, IPL's DG technical potential was estimated as 7.5 MW across its Minnesota and Iowa service areas. Today the installed capacity is approximately 114 MW (total IPL):

Table 4.0 Technology Contributions of DG Capacity (<10 MW)

Technology	Total DG kW	Percent of IPL DG Capacity
Wind	77,750	68.4
Demand Response	17,942	15.8
Hydro	8,340	7.3
Solar Photovoltaic	5,461	4.8
Combined Heat & Power	3,306	2.9
Farm Biogas	939	0.8
Total	113,738	100

For this 2014 Resource Plan, IPL retained Tetra Tech, Inc. (Tetra Tech) to perform an updated DG potential study which is provided in Appendix 4A. The

[1] For the purposes of this filing, a distributed generation (DG) facility is an electricity generating facility located near the end-user or where it will deliver power back into a utility's distribution system. DG units are smaller units with sizes ranging from less than 1 kW to 80 MW, but most are typically less than 20 MW. DG facilities include: stand-by power generators utilizing any fuel source, alternative energy production systems (e.g., biogas, biomass, hydro, solar, wind), cogeneration facilities, microturbines and reciprocating engines.

DG technologies are customer-sited or wholesale DG systems of a scale smaller than is typically considered by a utility for its own central power station use, but growing with increasing frequency in U.S. electricity markets. The technology types include:

- Solar photovoltaics;
- Wind energy systems;
- Biogas from animal waste and wastewater treatment plants;
- Landfill gas systems; and
- Combined heat and power options.

These technologies were selected because they already exist or exhibit growth in the IPL service territory, or because they show near-term commercial potential based on their adoption in other utility service territories in the United States.

4.1 DG Forecasts

Three forecasts for the DG technologies are provided in the 2014-2029 study period. These forecasts provide views for the market that reflect drivers in policy that could enhance or inhibit greater adoption rates:

- **"Base Case"** – For solar electric and small and medium wind energy technology, the Base Case is framed by the expected sunset of the federal investment tax credit (ITC). The ITC has provided significant capital cost reduction value to many DG technologies. For some technologies, such as MW-class wind, the tax credits available through the federal production tax credit (PTC) or ITC conversion have expired and a Low Policy support case (described below) already exists. For solar and small and medium wind energy systems, the ITC offers a 30 percent tax credit, set to expire December 31, 2016. After 2016, solar electric technologies will still be able to leverage a 10 percent ITC.
- **"High Policy"** – The High Policy scenario is defined by two policy options, applied to different technologies. For solar electric and small/medium wind, the High Policy scenario assumes the federal ITC is extended indefinitely. The Energy Information Administration (EIA) modeling is used to consider the impact of an ongoing ITC for these technologies. In the case of other DG technologies, a $21 per metric carbon ($CO_2$) ton tax starting in 2017 is used to model the financial performance of each technology. The underlying scenario assumption is that investors in MW-class wind, biogas, landfill gas, and combined heat and power technologies make the investment based on a financial return (so called, investment grade DG). These systems are modeled based on a forecasted power purchase agreement (PPA) value compared to a general levelized cost of energy for each technology.
- **"Low Policy"** – The Low Policy scenario considers the effect of reduced financial benefit on market adoptions. In the case of investment grade DG, the PPA value is driven by utility avoided costs, which is assumed to serve as a floor for potential economic drivers.

Effectively, the Base Case and Low Policy case are the same for these technologies. With the removal of the federal PTC and ITC requirements that these technologies have construction beginning by December 31, 2013, the effect of known federal incentives is limited for the vast majority of the forecast timeframe. For technologies that typically operate in a net-metered arrangement (solar and small/medium wind), the Low Policy case is defined by possible changes to net metering that would reduce the value of these technologies. In aggregate, the Low Policy case is not significantly different from the Base Case in terms of installed capacity, though specific technologies are significantly impacted.

In all scenarios, 2017 is used as the year in which policy shifts occur, with the Minnesota distributed solar electric carve-out effect beginning in 2014. The \$21 per metric ton of CO_2 tax policy was modeled as starting in 2017. The federal ITC ends in 2017. As a result, the scenario models are identical in outcome from 2014–2016.

4.2 DG Study Results

The aggregate model results for each scenario are presented below. The results show the incremental additional capacity through the forecast period at the distribution system level. The results exclude existing DG system contributions.

Table 4.2 Cumulative Additional DG Capacity, IPL 2014–2029

Year	MWH			Gross MW (Nameplate)			Summer Peak Contribution MW		
Scenario	Base	High	Low	Base	High	Low	Base	High	Low
2014	6,740	6,740	6,740	5.3	5.3	5.3	1.9	1.9	1.9
2015	10,117	10,117	10,117	7.7	7.7	7.7	2.7	2.7	2.7
2017	23,391	38,094	23,110	12.6	18.5	12.5	4.9	5.6	4.8
2020	68,814	152,041	67,408	19.8	47.5	18.9	10.3	15.9	10.1
2025	131,707	349,812	127,413	29.9	101.5	27.2	17.8	32.8	17.0
2029	228,588	490,280	220,925	59.9	146.4	55.0	23.6	43.0	22.2

The technology that exhibits the greatest gross impact among the scenarios is MW-class wind. This technology shows substantial sensitivity to the \$21 per metric ton CO_2 tax, with market adoptions beginning to occur early in the forecast period for the High Policy case, but only in the last few years of the Base Case and Policy case. Biogas also shows significant effects of the High Policy case, with the \$21 per metric ton CO_2 tax effect enhancing the economics of such projects. Solar electric shows the greatest variation among the three scenarios, driven by the EIA scenario forecasts and Low Policy growth rate reductions.

The High Policy case and its significantly higher MW and MWh adoption illustrates the sensitivity to financial incentives that DG technology markets may respond. Conversely, the narrower gap between the Base Case and Low Policy case illustrates that in the current situation, the Base Case results suggest that expiring policy support will mute the growth of DG technology markets.

There are many possible specific energy policy outcomes that could create higher adoptions than the Base Case. Indeed, the markets themselves may drive innovation or create new value propositions that enhance DG adoption. This forecast is not meant to be a specific policy modeling exercise, but to capture a possible effect of policy on market adoptions of DG technology and create a conservative forecast that a utility can use to make decisions on power supply planning. It should not be viewed as modeling the maximum technical potential or otherwise placing a ceiling on market potential.

4.3 DG Results versus Load Forecast Range

While many DG technologies have shown significant individual growth, the aggregate energy supply remains relatively small compared to total IPL load. Further, DG projections in the Tetra Tech study remain relatively small in comparison to the load forecast growth and bandwidth used in the 2014 Resource Plan. To illustrate, see the graphs below:

Chart 4.0, DG Scenario Impacts on IPL Peak Load (MW)

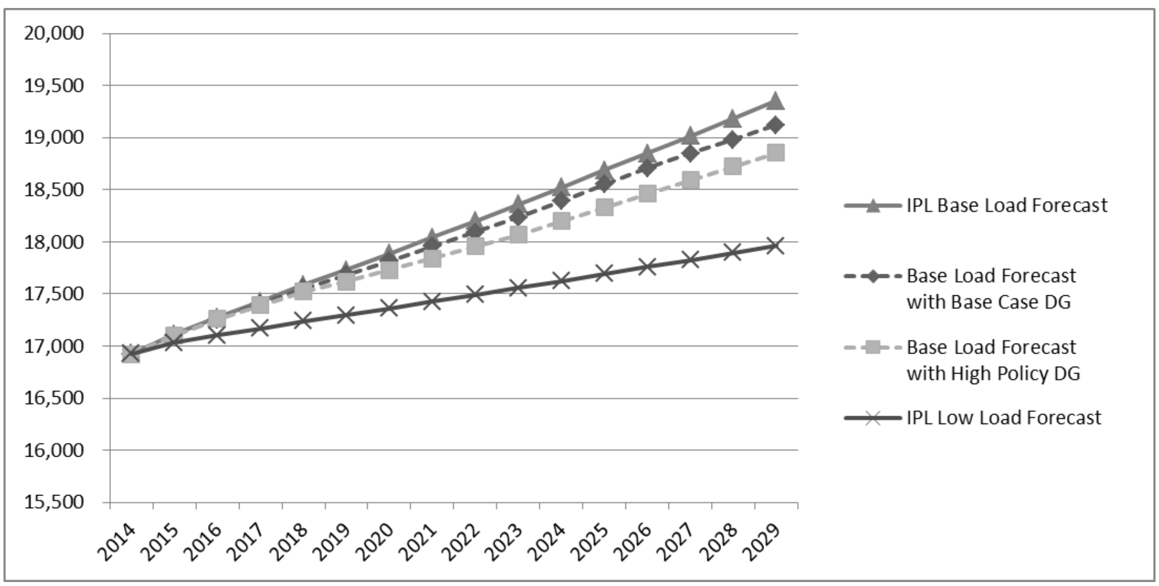
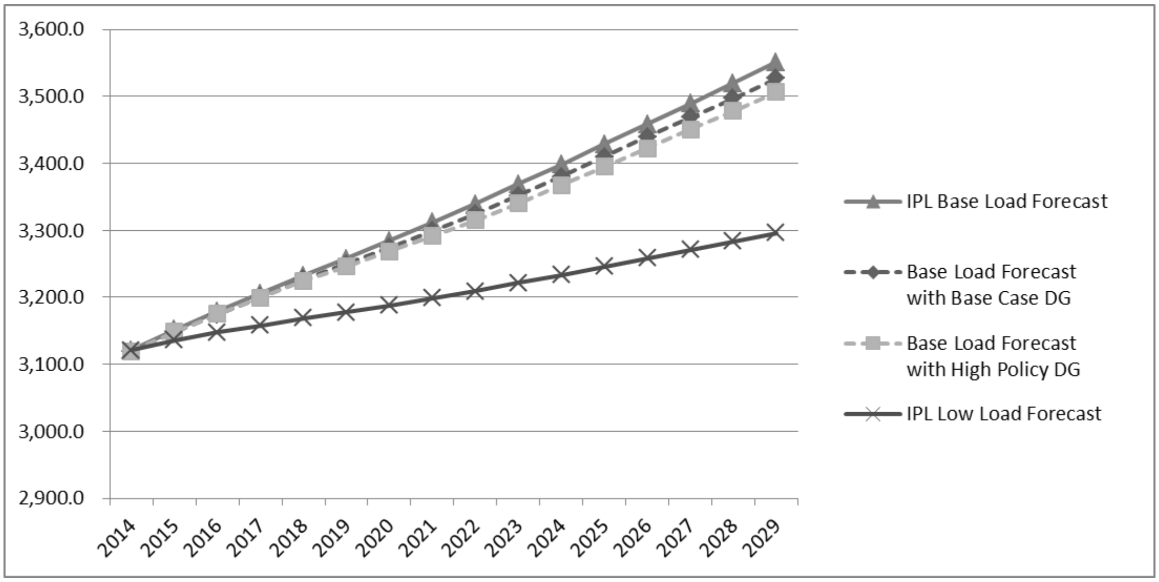


Chart 4.1, DG Scenario Impacts on IPL Energy (GWH)



TETRA TECH

complex world | CLEAR SOLUTIONS™

Interstate Power & Light

Distributed Generation Market Forecast

March 14, 2014

Interstate Power & Light

Distributed Generation Market Forecast

March 14, 2014

Tetra Tech
6410 Enterprise Lane, Suite 300 | Madison, WI 53719
Tel 608.316.3700 | Fax 608.661.5181
www.tetratech.com

TABLE OF CONTENTS

1. INTRODUCTION

Alliant Energy retained Tech, Inc. (Tetra Tech) to provide a market forecast for distributed generation in the Interstate Power & Light (IPL) service territory for the 2014–2029 time period. This report describes the technologies considered, model development, and results of the research and modeling conducted by Tetra Tech. The forecast covers major distributed generation technology markets already in place in the IPL territory or the US in general. These technologies were modeled as customer sited or wholesale distributed generation systems of a scale smaller than is typically considered by a utility for its own central power station investments. Although distributed generation makes up a small segment of the electricity generation market, it is a segment growing faster than the general US electricity market.

The forecast presents three scenarios covering the 2014–2029 time period. The three scenarios were developed to capture high, medium (base case), and low adoption rates. As the energy policy environment significantly influences the market for distributed generation technologies; these scenarios were developed to recognize the potential influences of those policies on distributed generation adoption.

The results of the forecast are based on estimates of market adoption rates for each technology and can be used by IPL for estimating customer electricity loads net of distributed generation or for planning generation resources and market-based supply. The forecasts are not meant to capture the maximum technical potential of distributed generation or maximum or minimum market potential adoption rates. The drivers of distributed generation investments are diverse and driven by technology cost trends, electricity prices experienced by investors to drive investment returns, capital availability within markets to drive investments, and state, local, and federal policies.

In this report we present the summary findings and conclusions along with the key policy considerations and data sources used to derive the forecasts. The methodology for each technology and detailed technology modeling results are presented in separate technology-focused sections.

Below we document the technologies included in this study. These technologies are present and exhibiting growth in the IPL service territory or show near-term commercial potential based on their adoption in other utility service territories in the US

- Solar photovoltaics
- Wind energy systems
- Biogas from animal waste and wastewater treatment plants
- Landfill gas systems
- Combined heat and power options.

The forecast targeted these technologies as a means of addressing the aggregate distributed generation planning forecast. The size ranges considered were meant to allow for analyzing aggregate market effects that drive adoptions, rather than specific applications or configurations of the technologies. Specific customer or technology applications cannot be forecasted. Thus, the forecast results and technology selection should not be viewed as making a claim that no other potential technologies or specific situations may lead to additional or substitutive adoptions of distributed generation.

2. EXECUTIVE SUMMARY

Over the last decade, electric utilities around the US have experienced substantial changes to the market for distributed electricity generation. Significant volumes of distributed generation have been added in response to equipment price declines, increased customer awareness and interest in distributed generation, increases in electricity prices, standardized market transactions and increases in incentives. In 2001, IPL's distributed generation technical potential was estimated as 7.5 MW across its Iowa and Minnesota service areas. Today the installed capacity is over 113 MW.

Table 2-1. Technology Contributions of Distributed Generation Capacity (<10 MW)

Technology	Total DG kW	Percent of IPL DG Capacity
Wind	77,750	68.4
Demand Response	17,942	15.8
Hydro	8,340	7.3
Solar Photovoltaic	5,461	4.8
Combined Heat & Power	3,306	2.9
Farm Biogas	939	0.8
Total	113,738	100.0

The forecast for distributed generation technologies in IPL's territory is based on three scenarios that reflect drivers in policy that could enhance or inhibit greater adoption. For solar electric and small and medium wind energy technology, the base case is framed by the expected sunset of the federal investment tax credit (ITC). This tax credit has provided significant capital cost reduction value to many distributed generation technologies. For some technologies, such as MW-class wind, the tax credits available through the federal production tax credit (PTC) or ITC conversion have expired and a low-policy support case already exists. For solar and small and medium wind energy systems, the ITC offers a 30 percent tax credit, set to expire Dec 31, 2016. After 2016, solar electric technologies will still be able to leverage a 10 percent ITC.

For the high-policy case, the scenario is defined by two policies options, applied to different technologies. For solar electric and small/medium wind, the high-policy scenario assumes the federal ITC is extended indefinitely. The Energy Information Administration (EIA) modeling is used to consider the impact of an ongoing ITC for these technologies. In the case of other DG technologies, a $21 per metric carbon ton tax starting in 2017 is used to model the financial performance of each technology. The underlying scenario assumption is that investors in MW-class wind, biogas, landfill gas, and combined heat and power technologies make the investment based on a financial return (so called, investment grade distributed generation)[1].

[1] The use of the term "investment grade" distributed generation is not meant to imply that solar electric or small/medium wind market adoptions are not done for non-financial reasons. The differentiation is meant to capture the broader perspectives on historic adoptions that are often not driven primarily by financial returns. It also segments the distributed generation market that is influenced by the federal ITC compared to the expired PTC.

These systems are modeled based on a forecasted power purchase agreement value compared to a general levelized cost of energy for each technology.

The low policy case considers the effect of reduced financial benefit on market adoptions. In the case of investment grade distributed generation, the PPA value is driven by utility avoided costs, which we assume serves as a floor for potential economic drivers. Effectively, the base case and low-policy case are the same for these technologies. With the removal of the federal PTC and ITC requirements that these technologies have construction beginning by Dec 31, 2013, the effect of known federal incentives is limited for the vast majority of the forecast timeframe. For technologies that typically operate in a net-metered arrangement (solar and small/medium wind), the low-policy case is defined by possible changes to net metering that would reduce the value of these technologies. Specifically, it uses the effect of shifting from an annual net metering true-up to a monthly net metering true-up, similar to a policy shift experienced by Wisconsin Public Service Corporation net metering customers in the 2012 timeframe. In aggregate, the low-policy case is not significantly different from the base case in terms of installed kWh, though specific technologies are significantly impacted.

In all scenarios, 2017 is used as the year in which policy shifts occur, with the Minnesota distributed solar electric carve-out effect beginning in 2014. The $21 per metric ton of CO_2 tax policy was specifically requested by Alliant Energy to be modeled as starting in 2017. The federal ITC ends in 2017. As a result, the scenario models are identical in outcome from 2014–2016.

Below, we present the aggregate model results for each scenario. Subsequent sections for each technology provide additional detail for their respective technologies. The results show the incremental additional capacity through the forecast period at the distribution system level. The results exclude existing distributed generation system contributions.

Table 2-2. Cumulative Additional Distributed Generation Capacity, IPL 2014–2029

Year	MWh			Gross MW[2]			Summer Peak MW		
Scenario	Base	High	Low	Base	High	Low	Base	High	Low
2014	6,740	6,740	6,740	5.3	5.3	5.3	1.9	1.9	1.9
2015	10,117	10,117	10,117	7.7	7.7	7.7	2.7	2.7	2.7
2017	23,391	38,094	23,110	12.6	18.5	12.5	4.9	5.6	4.8
2020	68,814	152,041	67,408	19.8	47.5	18.9	10.3	15.9	10.1
2025	131,707	349,812	127,413	29.9	101.5	27.2	17.8	32.8	17.0
2029	228,588	490,280	220,925	59.9	146.4	55.0	23.6	43.0	22.2

The technology that exhibits the greatest gross impact among the scenarios is MW-class wind. This technology shows substantial sensitivity to the $21 per metric ton CO_2 tax, with market adoptions beginning to occur early in the forecast period for the high policy case, but only in the last few years of the base case and low policy case. Biogas also shows significant effects of the high policy case, with the $21 per metric ton CO_2 tax effect enhancing the economics of such projects. Solar electric shows the greatest variation among the three

[2] For solar electric technology, gross MW is included on a DC basis. For solar electric MWh and Summer Peak MW, and for all other technologies, results are in AC.

scenarios, driven by the EIA's scenario forecasts and application of the low-policy growth rate reduction to the estimated rate of growth.

The high policy case and its significantly higher MW and MWh adoption illustrates the sensitivity to financial incentives to which distributed generation technology markets may respond. Conversely, the narrower gap between the base case and low policy case illustrates that in the current situation, the base case suggests that expiring policy support will mute the growth of distributed generation technology.

There are many possible specific energy policy outcomes that could create higher adoptions than the base case or even the high policy case. Indeed, the markets themselves may drive innovation or create new value propositions that enhance distributed generation adoption. This forecast is not meant to demonstrate the effect of specific policies, but to capture a possible effect of general policy directions on market adoptions of distributed generation technology and create a conservative forecast that a utility can use to make decisions on power supply planning. The study does not present the maximum technical or maximum market potential of distributed generation. While many distributed generation technologies have shown significant individual growth, the aggregate distributed generation energy supply remains relatively small compared to total IPL loads. As such, we estimate that there is room for additional and significant growth, with policy and the economics of distributed generation affecting the growth that is ultimately achieved.

3. SCENARIO DESCRIPTIONS

3.1 INTRODUCTION

Three scenarios were developed to model the base case, high adoption, and low adoption rates for distributed generation. The three scenarios are based on the theory that policy is a major driver of distributed generation systems and will have a significant influence on market adoption. The base case assumes existing known policy continues as stipulated. The high adoption scenario, "higher policy case," is based on an effect of key policies continuing or being implemented. The low adoption scenario is based on a "lower policy case" in which changes in policy drive down adoptions from the base case. Below we describe each scenario and the policy considerations used to develop that scenario.

The policy framework for the scenarios segment distributed generation into two groupings:

1) Net-metered systems:
   a. Solar electric
   b. Small and medium wind
2) Larger distributed generation systems typically installed primarily as an investment. These are:
   a. MW-class wind
   b. Landfill Gas
   c. Biogas
   d. Combined Heat and Power.

The net-metered systems exhibit large numbers of systems, though of relatively small kW capacities for each installation. To a degree they are commodity products. The forecasts for these systems are based on recent past market adoptions to inform IPL specific adoptions through 2016 and leverage Energy Information Administration forecasts for long-term projections after 2016. In contrast, the larger distributed generation systems are modeled based on a levelized cost of energy compared to a forecasted estimate of a power purchase agreement to determine cost effectiveness through the forecast period.

In the case of solar electric systems, Minnesota currently requires that 1.5 percent of an electric utility's load will be met with solar electric systems, with 10 percent of that amount to be supplied by systems 20 kW and less. The first target year, 2020, is used to set a growth rate from 2014, with the general EIA growth rate assumed thereafter. For the years 2014–2020, there is no distinction made in the growth of smaller solar electric system in Minnesota in any of the three scenarios.

Below we describe each of the three scenarios and policy considerations that drive forecasted market adoptions in each scenario.

3.2 BASE CASE SCENARIO

The base case scenario assumes the federal investment tax credit (ITC), currently set to expire at the end of 2016, will not be extended further and will expire on December 31, 2016.

The ITC, which provides a 30 percent tax credit for solar electric and wind systems 100 kW and less, among other distributed generation technologies, has played an important role in reducing capital costs for adopters of distributed generation technologies. Upon expiration of the credit, solar electric systems installed after 2016 will be capable of receiving a 10 percent tax credit. Small wind systems will receive no tax credit.

Under this scenario, the years in which the ITC is active were modeled separately from the remaining years for specific technologies. Namely, for the period of 2014–2016, growth rates of solar electric and small and medium wind turbines in Iowa were forecast using information about existing installations and capacity between 2008 and 2013. Upon expiration of the ITC (December 31, 2016), the cumulative growth rate of non-marketed solar electric systems provided in the reference case of the EIA 2013 Annual Energy Outlook was used to estimate growth of solar electric technologies in Iowa.

A similar approach was used to forecast small and medium wind turbine growth in IPL's territories. The EIA 2013 Annual Energy Outlook provided a non-marketed wind growth rate of 0 percent following the expiration of the ITC, a figure we believe is unreasonable given market adoptions in IPL territory prior to the ITC's existence. Based on growth rates of wind capacity in Iowa between 2008 and 2013, we forecast installations between 2014 and 2016, after which we employed the growth rate of non-marketed solar photovoltaic systems in EIA's 2013 Annual Energy Outlook.

In Minnesota, existing installations of solar electric technologies were used as the starting point to forecast adoptions in 2014 and later. However, unlike Iowa, Minnesota has a renewable portfolio standard with a solar obligation, requiring investor-owned utilities to acquire 1.5 percent of their generating capacity from solar systems by 2020, while simultaneously mandating 10 percent of the solar requirement come from systems of 20 kW or smaller.[3] To account for this, we estimated 1.5 percent of IPL's Minnesota load in 2020 and then calculated the growth rates needed to obtain 10 percent of its solar requirement from systems 20 kW or less. After 2020, the cumulative growth rate of non-marketed solar electric systems provided in the reference case of the EIA 2013 Annual Energy Outlook was used to estimate growth of solar electric technologies in Minnesota.

For larger distributed generation systems, we assumed that a 15-year power purchase agreement (PPA) rate would set the value from which the levelized cost of energy could be compared. The PPA forecast was based on 2013 avoided cost information provided by IPL and inflated by the wholesale electricity rate as forecasted by Wood Mackenzie for IPL. For a given year in the forecast, the net present value of the stream of avoided costs were levelized into a PPA rate that would hold through the 15-year PPA contract period.

The levelized cost of energy for each technology was calculated, allowing for a comparison of the cost of energy to the PPA value. Net present value calculations used the weighted average cost of capital provided by IPL (7.44 percent). The specifics for each technology are described in each technology section of the report.

In the base case, there are no significant policy incentives applied to the scenario other than a five-year MACRS depreciation schedule. This reflects the ending of the federal production

[3] MN § 216B.1691(2f).

tax credit for biogas and wind energy systems in 2013. For these technologies, the base case is identical to the low-policy case.

3.3 HIGH-POLICY SCENARIO

The high policy scenario, based partially on the "No Sunset" case in EIA's 2013 Annual Energy Outlook, considers the implications of extending the ITC indefinitely for solar electric systems and small and medium wind systems. Again, in Iowa, growth rates of solar systems and small and medium wind turbines between 2014 and 2016 were estimated using growth rate information from IPL for 2008 through 2013, at which point the EIA's "No Sunset Case" annual growth rate for non-marketed solar photovoltaic systems was used for the remainder of the forecasting period.

Similar to the base case scenario, small and medium wind turbine growth between 2014 and 2016 is modeled using growth rates between 2008 and 2013 in IPL's territory, at which point EIA's "No Sunset" growth rate for solar photovoltaic systems was employed.

Finally, growth of solar installations in Minnesota was modeled similarly to the base case scenario, taking renewable portfolio standards into account through 2020. Beginning in 2021, the EIA's "No Sunset" growth rate for non-marketed solar photovoltaic systems was employed.

For larger distributed generation systems, the forecast relied on a specific policy—assuming a $21 per metric ton carbon tax was instituted. The forecast assumes that this value would be reflected in the estimated PPA rates, converting the $21 per metric ton carbon to an additional $20.27 per MWh in the estimated PPAs. The conversion from $21 per metric ton was based on the current emissions rate from the EPA eGRID database for the MRO West region of 2,127.82 lbs of CO_2 equivalent per MWh (this includes fugitive methane and N_2O emissions). In the case of combined heat and power systems, the increased use of natural gas by the system owner would also be taxed at the same rate, dampening the value of avoided electricity emissions by the EPA's emission rate of 53.06 kg CO_2/mmbtu.

The $21 per metric ton tax could not be applied to the net-metered systems as the specific effect on the rates or policies of IPL to incorporate that value are unknown. Given the mix of fixed and variable costs in retail rates, modeling a specific effect on net-metered systems would require significant speculation. For this reason, the high policy scenario relied on the continuation of the federal investment tax credit as the policy to drive net-metered distributed generation systems (solar electric and small/medium wind).

3.4 LOW-POLICY SCENARIO

The low policy scenario assumes an environment that makes investment in distributed generation technologies less attractive. Examples include removing utility incentives, enacting two-tied rate structures or shifting to monthly net metering true-ups over the traditional annual true-ups. Our model takes these types of distributed generation policies into account by reducing the EIA reference case growth rate by 75 percent for solar electric and small/medium wind systems. As shown in Table 3-1, this decrease is in line with the reduction witnessed by the Wisconsin Public Service Corporation between 2011 and 2013, a period during which a two-tiered net metering structure coupled with monthly netting was enacted, along with a significant reduction and cancellation of Focus on Energy renewable energy incentives.

Table 3-1. Interconnection Requests Made to WPSC by Year[4]

Year	Residential	Commercial/Industrial	Total
2011	52	26	78
2012	32	6	38
2013[5]	12	6	18
Decrease (2011–2013)	76.9%	76.9%	76.9%

As in the base case scenario, growth rates of solar systems and small and medium wind turbines in Iowa between 2014 and 2016 were estimated using growth rate information from IPL for 2008 through 2013. For the remaining years in our estimation we used the EIA's "reference case" annual growth rate, reduced by 75 percent, for non-marketed solar photovoltaic systems.

The growth of solar installations in Minnesota used the base case scenario, taking renewable portfolio standards into account through 2020. Beginning in 2021, the EIA's "reference case" growth rate for non-marketed solar photovoltaic systems was employed, which assumes that using the EIA's reference case growth rates will allow for ongoing RPS compliance in Minnesota.

[4] "Wisconsin Public Service Corporation, Docket 6690-UR-122 (PSC Ref# 190934).
[5] 2013 numbers are estimated using prorated year-to-date (through August 2013) data.

4. SOLAR ELECTRIC

4.1 TECHNOLOGY OVERVIEW

Distributed solar electric systems (photovoltaics) have seen a steep rise in adoption in the IPL service territory since 2007. In 2007, IPL had approximately 17 kW of distributed solar electric capacity. At the end of 2013, that capacity grew to 5,160 kW. During the 2008–2013 timeframe, federal, state, and utility incentives were active in the IPL market. Additionally, the solar electric market has exhibited significant price decreases for installed system costs.[6] For IPL, most of the growth occurred in Iowa, with Minnesota having only 76 kW of installed capacity by the end of 2013.

All existing systems in IPL's service territories fall under net metering limits. In Iowa that limit is set at 500 kW. In Minnesota, the limit has historically been 40 kW, though legislation in 2013 raised that cap to 1,000 kW. Table 4-1 illustrates the sector and size breakdown of distributed solar electric systems installed in IPL's service territory through 2013.

Table 4-1. IPL Distributed Solar Segmentation, EOY 2013

Segment	System Count	Total DC Solar Electric Capacity	Average DC kW	Percent of Solar Electric Capacity
Residential	219	1,529 kW	7.0 kW	29.6%
Nonresidential <25 kW	128	1,431 kW	11.4 kW	27.7%
Nonresidential >25	33	2,200 kW	67.0 kW	42.6%
Total	380	5,160 kW	12.6 kW	99.9%

As illustrated in Table 4-1, larger nonresidential systems (>25 kW) have fewer installations than other segments but have grown to represent nearly 43 percent of the distributed solar electric capacity in the IPL territories. All of these larger systems were installed between 2011 and 2013, signifying large growth in this segment, though all segments experienced sustained growth in the 2008–2013 timeframe.

While the growth experienced through 2013 is significant, it is less clear that future growth will continue at the same level. According to Alliant Energy, IPL's Iowa incentive program ended at the end of 2013, though a large number of program enrollments prior to 2014 will results in program funds being applied to system installations in 2014.[7] In 2017, the federal investment tax credit will decrease from a 30 percent tax credit to a 10 percent tax credit. The Iowa renewable energy tax credit, currently scheduled to end in 2015, has not been used to leverage large IPL solar electric systems to date. On the other hand, Minnesota has expanded its Renewable Portfolio Standard to include a solar carve-out (1.5 percent of load), of which 10 percent must come from systems less than 20 kW. Given the relatively low penetration of solar electric systems in the Minnesota portion of the IPL territory, significant growth of distributed solar electric systems in Minnesota will be required in order to meet the RPS requirement.

---

[6] "Tracking the Sun VI – An Historical Summary of the Installed Price of Photovoltaics in the united States from 1998 to 2012." Barbose et al. July 2013. Lawrence Berkeley National Laboratory.
[7] K. King, personal communication, January 22, 2014.

4.2 METHODOLOGY

The methodology we used to forecast additional distributed solar electric systems relies on several key assumptions:

- The Minnesota distributed solar portion of the renewable portfolio standard solar carve-out will determine the growth in Minnesota through 2020, the first target year of the RPS.
- The removal of IPL incentives in Iowa for solar electric systems will, after 2014, exhibit similar market effects as experienced by Alliant Energy in their WPL territory following the pullback of solar electric incentives.
- Energy Information Administration (EIA) AOE 2013 projections for cumulative growth rates of non-marketed solar electric systems are applicable to the IPL solar electric market in Iowa for 2017 and later, whereas EIA growth rates will take over after 2020 in Minnesota.
- Growth patterns through 2016 will reflect the presence of the federal ITC.
- Existing capacity is maintained or replaced at the same level of performance, with the forecast reflecting incremental additions of solar electric capacity
- Energy production estimates can be modeled using PV Watts v.1[8] default fixed-tilt system inputs with Waterloo, IA as the representative location of systems.
- There are no system technical constraints to adding distributed solar capacity during the forecast period.

To model energy production for solar electric systems, PV Watts v.1 provides estimates of AC system output using standard equations and derates for system components, shading, and other factors. Using PV Watts v.1, we estimated that each 1 kW of DC solar system capacity could be expected to produce 1,249 kWh of electricity each year. While PV Watts v.1 shows a two-axis tracking system producing 1,678 kWh per kW of DC capacity per year, we selected the fixed axis system as the default due to a lack of information regarding IPL market adoptions and to ensure a conservative estimate of kWh production from the systems.

Table 4-2 illustrates market estimates for typical system installations in each of the market segments we identified. Residential systems are represented by a 5 kW DC system, with small nonresidential systems represented by a 10 kW DC system. Large nonresidential systems are based on a 100 kW DC system.

[8] http://rredc.nrel.gov/solar/calculators/pvwatts/version1/.

Table 4-2. Distributed Solar Electric System Characteristics

	Residential	Small Nonresidential	Large Nonresidential
Capacity (DC kW)	5 kW	10 kW	100 kW
Capacity (AC kW)	3.8 kW	7.7 kW	77 kW
Estimated kWh, Waterloo, IA	6,245	12,491	124,906
Installed cost (2012$ per DC kW)[9]	$5,600	$4,900	$4,600
Fixed O&M (2012$ per kW-yr)[10]	$18	$18	$10
Variable O&M	NA	NA	NA

Our forecasting for distributed solar electric systems did not rely directly on the economics of the technology. The approach considered the market behavior in the past six years, adjusted for changes to utility incentives and the Minnesota RPS requirements, and relied on the EIA's forecast for non-marketed solar electric cumulative growth for 2017 and later (after 2020 for MN). We decided against using a direct economic model for solar electric systems due largely to the significant recent growth, ongoing price decreases, and uncertainty regarding market decisions for installing solar electric systems.

We assumed that IPL customers are installing solar electric systems for multiple reasons, only some of which *may* be economic. Many models of solar electric economics indicate that despite the presence of incentives, many adoptions would not be economically beneficial from a strict financial performance and that the mix of incentives for any customer or customer group have varied over time and not consistently applied.

Our model used the annual energy output figures for each of the existing market segments as a starting point for our forecasts. Each forecast relied on EIA 2013 AEO projections after the year 2016, with the exception of the Minnesota residential and small nonresidential segments that fall under the RPS requirements. Specifically, we used the non-marketed residential and commercial solar PV 40-year projections for the pertinent years.

We used two different versions of these projections: the EIA reference case growth rates were used for our base case scenario and as a basis for our low policy support scenario, and the EIA "no-sunset" case growth rates was used for our high policy support scenario. These EIA-based projections captured the anticipated solar PV adoption rate based on observed market behavior. The base case reflects anticipated market behavior given the expiration of various federal incentives, while the "no-sunset" case stipulates existing policy support remains unchanged for the foreseeable future.

[9] Barbose, Galen, Naïm Darghouth, Samantha Weaver, and Ryan Wiser. "Tracking the Sun VI: An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012." Lawrence Berkeley National Laboratory, 2013. P. 23.

[10] Tidball, Rick, Joel Bluestein, Nick Rodriguez, and Stu Knoke. "Cost and Performance Assumptions for Modeling Electricity Generation Technologies." National Renewable Energy Laboratory 2010.

The next sections discuss the individual state forecast methods.

4.2.1 Minnesota

The forecast for IPL's distributed solar electric market includes a specific call-out for Minnesota. The RPS requires that 1.5 percent of the energy supplied by a utility must be from solar electric systems, with 10 percent of that amount provided by systems 20 kW and less. As this is a significant policy that is in place and without a sunset, for the Minnesota portion of IPL's distributed generation market, we assume that the Minnesota RPS sets the market for distributed generation in IPL's Minnesota territory through 2020. 2020 is the first target year for this portion of the RPS, and growth to that target is consistent for all three scenarios. The target must be met in all subsequent years, but EIA growth forecasts are used after 2020.

To model the required 2020 target, we reviewed an IPL Minnesota load forecast. In 2020, the IPL load forecast estimates a Minnesota load of 854,304 MWh. Additionally, the solar carve-out excludes specific loads from some industrial customer segments. We reviewed a 2013 filing with the Minnesota Public Utilities Commission from IPL that described this excluded load based on 2012 load data. To arrive at the excluded load, we assumed this load would grow by the same percentage as the overall utility load. This excluded load is estimated as 11,632 MWh in 2020, resulting in a total load applicable to the distributed solar electric carve-out of 842,672 MWh in 2020. Applying the 1.5 percent solar electric RPS carve-out and 10 percent distributed solar carve-out resulted in an estimated 1,264 MWh of distributed solar being required to meet the 2020 RPS target.

Meeting the 1,264 MWh requirement by 2020 will require a total of 1,012 kW of DC solar electric capacity in 2020, based on an assumed 1,249 kWh per kW DC performance factor. Growing from 76 kW in 2013 to 1,012 kW in 2020 will require a compound annual growth rate of 44.7 percent through the seven-year period. This growth rate is a significant departure from the EIA's assumed growth rate from 2017 and later and represents an order of magnitude of growth for IPL's Minnesota service territory. While a portion of the existing solar electric base in Minnesota will not be able to contribute to the RPS requirement, it is unclear exactly how much will be excluded and amounts to a small percentage of the required capacity in 2020. Other uncertainties include the specific load in 2020 and how much of the solar electric production from earlier years may result in bankable credits that can be used in 2020.

Beyond 2020, our forecast utilized the EIA assumed rate of growth of their reference case for the forecast's base case and low-policy case. For the high-policy case, the EIA's "no sunset" case growth rate was used after 2020. Using the EIA's reference case growth rates post-2020 will allow IPL to continue to meet its distributed solar carve-out as load grows, and be slightly in excess. We did not make an adjustment for the low-policy case as such a policy shift would cause significant risk to IPL fulfilling the RPS distributed solar electric requirement.

Our forecast was not based on speculation regarding the methods by which IPL would meet its distributed solar electric RPS obligations. In addition, while the Minnesota territory has not experienced "large" nonresidential solar electric systems in the past, we accounted for the potential for these systems by assuming a single 100 kW system would be installed in 2015, with EIA growth rates driving additions 2017 and later in the base case and high-policy case. In the low-policy case, the low-policy growth rate is assumed (75 percent less than the base case). The growth in these large systems was quantified in the forecast in small increments, reflecting the cumulative growth. It is unclear when or in what quantity larger systems would be installed. We speculate that the presence of the RPS carve-out for distributed solar may create a relative disincentive for larger systems, depending on the mechanism used to grow the market to the 2020 target.

Table 4-3. Forecasted Growth Rates for Solar Capacity, Key Time Periods (Minnesota)

Time Period	Annual Cumulative Growth Rate	Assumptions
2014–2020 (base case and low-policy scenarios)	44.7 percent for small residential and small nonresidential 0.9 percent for large nonresidential	Compound annual growth rate needed to meet 2020 RPS solar requirement Assumes EIA reference case solar growth rate for nonresidential customers
2014–2020 (high-policy scenario)	44.7 percent for small residential and small nonresidential 2.2 percent for large nonresidential	Compound annual growth rate needed to meet 2020 RPS solar requirement Assumes EIA "no sunset" case solar growth rate for nonresidential customers
Base Case 2021–2029	Residential – 1.3 percent on average Small Nonresidential – 2.7 percent on average Large Nonresidential – 2.7 percent on average	Assumes EIA reference case solar growth rate for residential and nonresidential customers
High-Policy Case 2021–2029	Residential – 9.5 percent on average Small Nonresidential – 4.0 percent on average Large Nonresidential – 4.0 percent on average	Assumes EIA "no sunset" case solar growth rate for residential and nonresidential customers
Low-Policy Case 2021–2029	Residential – 1.3 percent on average Small Nonresidential – 2.7 percent on average Large Nonresidential – 2.7 percent on average	Assumes EIA reference case solar growth rate for residential and nonresidential customers

4.2.2 Iowa

Our projection for IPL's Iowa territory accounts for short-term policy variance before switching to the EIA growth rates in 2017. Initially there is strong performance as 2013 late-year enrollment in IPL's Iowa incentive program is installed in 2014. This falls in 2015, mirroring the market effects observed in Alliant Energy's WPL territory following the expiration of solar electric incentives there. Starting in 2017, we switched to the corresponding EIA growth rates for each policy support scenario.

In our base case policy support scenario, we used the EIA base case growth rates for each segment. There are two different growth rates from the EIA, one for residential installations and one for commercial installations. We used the residential growth rates for the residential segment and the commercial growth rates for our nonresidential segments.

The low-policy support scenario discounts the EIA base case rate by 75 percent. This reflects the reduced level of growth in line with that experienced by the Wisconsin Public Service from 2010 to 2013. Discussion of this assumption can be found in the report section describing the policy scenarios.

The high policy support scenario used the EIA no-sunset case growth rate. That projection assumes that all current policies continue uninterrupted for the foreseeable future. Practically, that means that the federal ITC does not expire in 2016, so growth continues at the current rate.

Table 4-4. Forecasted Growth Rates for Solar Capacity, Key Time Periods (Iowa)

Time Period	Annual Cumulative Growth Rate	Assumptions
2014 (all scenarios)	100 percent for all sectors	2/3 of the average annual growth rate from 2012–2013
2015 (all scenarios)	16 percent for all sectors	Based on WPS growth rates between 2008–2012[11]
2016 (all scenarios)	25 percent for all sectors	Based on WPS growth rates between 2009–2012
Base Case 2017–2029	Residential – 1.1 percent on average Small Nonresidential – 2.4 percent on average Large Nonresidential – 2.4 percent on average	Assumes EIA reference case solar growth rate for residential and nonresidential customers
High-Policy Case 2017–2029	Residential – 2.3 percent on average Small Nonresidential – 3.6 percent on average Large Nonresidential – 3.6 percent on average	Assumes EIA "no sunset" case solar growth rate for residential and nonresidential customers
Low-Policy Case 2017–2029	25 percent of base case growth rates	Based on base case annual cumulative growth rates

[11] Based on review of WPL solar adoptions during 2008–2012 and K. King personal communication Jan 22, 2014.

4.3 RESULTS

The IPL total figures contain all the rating and projected annual output of IPL's service territory. We also included the additional cumulative solar electric capacity and energy of the Minnesota RPS-driven analysis. The findings are reported as additional kW and additional kWh, discounting Alliant Energy's current capacity through 2013. Peak summer MW contribution is based on multiplier of 48.7 percent, based on Black and Veatch modeling of Alliant Energy's hourly load profile.

Table 4-5. Base Case Distributed Solar PV IPL Forecast 2014–2029

Year	IPL Total MW	IPL Total MWh	IPL Total Summer Peak MW	MN RPS MW	MN RPS MWh
2014	5.1	6,393	2.5	0.03	43
2015	6.9	8,611	3.4	0.08	104
2016	9.9	12,383	4.8	0.16	193
2017	10.2	12,708	5.0	0.26	322
2018	10.5	13,128	5.1	0.41	509
2019	10.9	13,671	5.3	0.62	778
2020	11.5	14,368	5.6	0.94	1,169
2021	11.8	14,732	5.7	0.95	1,190
2022	12.1	15,122	5.9	0.97	1,213
2023	12.5	15,575	6.1	0.99	1,240
2024	12.9	16,071	6.3	1.02	1,269
2025	13.3	16,612	6.5	1.04	1,301
2026	13.7	17,156	6.7	1.07	1,333
2027	14.2	17,767	6.9	1.10	1,368
2028	14.8	18,464	7.2	1.13	1,409
2029	15.3	19,164	7.5	1.16	1,451

Table 4-6. Low-Policy Case Distributed Solar PV IPL Forecast 2014–2029

Year	IPL Total MW	IPL Total MWh	MN RPS MW	MN RPS MWh
2014	5.1	6,393	0.03	43
2015	6.9	8,611	0.08	104
2016	9.9	12,383	0.16	193
2017	10.1	12,563	0.26	322
2018	10.3	12,811	0.41	509
2019	10.5	13,159	0.62	778
2020	10.9	13,651	0.94	1,169
2021	11.0	13,784	0.95	1,190
2022	11.1	13,926	0.97	1,213
2023	11.3	14,082	0.99	1,240
2024	11.4	14,250	1.02	1,269
2025	11.6	14,433	1.04	1,301
2026	11.7	14,618	1.07	1,333
2027	11.9	14,820	1.10	1,368
2028	12.0	15,042	1.13	1,409
2029	12.2	15,264	1.16	1,451

Table 4-7. High-Policy Case Distributed Solar PV IPL Forecast 2014–2029

Year	IPL Total MW	IPL Total MWh	MN RPS MW	MN RPS MWh
2014	5.1	6,393	0.03	43
2015	6.9	8,611	0.08	104
2016	9.9	12,383	0.15	193
2017	11.1	13,861	0.26	322
2018	12.4	15,496	0.41	509
2019	13.9	17,305	0.62	778
2020	15.7	19,608	0.94	1,169
2021	17.3	21,642	1.01	1,259
2022	19.0	23,728	1.08	1,353
2023	20.7	25,890	1.16	1,450
2024	22.5	28,081	1.24	1,548
2025	24.3	30,342	1.32	1,650
2026	26.1	32,599	1.40	1,751
2027	27.9	34,854	1.48	1,853
2028	29.7	37,106	1.56	1,954
2029	31.5	39,378	1.65	2,057

5. WIND ENERGY

5.1 TECHNOLOGY OVERVIEW

Over the last decade, wind energy has expanded rapidly to become a significant source of new electricity supply. Iowa and Minnesota have seen significant expansions in wind energy capacity, particularly for utility scale wind farms. Both states have a significant geography with a high-quality wind resource. The major expansion of wind energy has been with large MW-class wind turbines located in utility or investor-owned wind farms. These installations each have a common point of interconnection and are connected to the electrical system at the transmission level, often in the tens to hundreds of MW. The character of the dominant wind development pattern is more akin to central power stations and not a distributed resource.

Although most wind energy development have not been distributed in nature, IPL has experienced growth in distributed wind energy resources as well. There are two dominant development models for distributed wind—small developments of MW-class turbines and customer-sited wind using small or medium wind turbines.

For purposes of forecasting additional wind energy installations for the IPL service territory, our analysis divided the wind market into two categories meant to capture core differences in the development models and investment decisions. The analysis assumed that MW-class wind systems are developed for purposes of financial gain, whereas small and medium wind turbines are developed for a mix of financial and aspirational value propositions. In general, we assume that investors in small and medium wind installations do so to offset their electricity consumption and for reasons beyond financial performance—the decisions may involve a mix of environmental ethics, goals for energy independence, social status, and other logics that extend beyond financial return.

IPL has a history with installations in both categories of the wind energy market. Table 5-1 illustrates the installed capacity of distributed wind systems in the IPL service territory at the end of 2013.[12]

Table 5-1. Distributed Wind Systems in IPL Through 2013

Wind Market Category	2013 EOY Installed Capacity	Percent of Distributed Wind Capacity	Total Capacity Growth 2007–2013
MW-Class (750 kW to 10 MW)	72,510 kW	93.3	55 percent
Medium Wind (50 kW to 750 kW)	2,935 kW	3.7	96 percent
Small Wind (less than 50 kW)	2,296 kW	3.0	550 percent
Total IPL DG Wind	77,741 kW	100	61 percent

[12] Source: Interstate Power and Light.

As Table 5-1 illustrates, MW-class installations of distributed wind dominate the installed capacity. Generally, wind energy developments and technology exhibit significant economies of scale, with larger turbines and multiple turbines per installations leading to better economics than smaller installations. However, all categories have experienced substantial growth over the last six years. Table 5-1 shows that distributed wind system capacity grew by 61 percent between 2008 and 2013. While most capacity was added in the MW-class category, small and medium wind turbines showed larger percentage growth.

During the 2008–2013 timeframe, a number of policy and market forces influenced the distributed wind market. These include the federal production tax credit (PTC), the federal investment tax credit (ITC), the Rural Energy for America Program (REAP), IPL customer incentives, and state level efforts to encourage market participation. Investors and developers of MW-class distributed wind projects sought to capture these incentives and leverage the technology and knowledge base of the utility-scale wind market. For small and medium wind, the market has shown maturation, with greater customer awareness and interest coupled to greater product availability. Along with favorable incentives, these factors may have been the significant market forces driving the small and medium wind market.

Both MW-Class and small/medium wind categories face economic and policy challenges and opportunities for the 2014–2029 forecast period. For MW-class wind, the federal PTC and ITC conversion expired at the energy of 2013. For small and medium wind turbines, the federal ITC expires at the end of 2016. REAP is an uncertain source of federal incentives linked to the Farm Bill, with IPL utility incentives having expired at the end of 2013 and with an unknown future. On the other hand, potential MW-class wind projects will leverage ongoing cost declines in the MW-class wind industry and the significant capital, labor, and knowledge base of Minnesota's and Iowa's utility scale-wind industry. The market for small and medium turbines can be expected to continue to reflect a maturing market with recently implemented equipment certification standards (AWEA 9.1) serving as a key driver of product quality.

With the existing pattern of distributed wind growth and the policy and market considerations in mind, we describe our forecasting methodology in the next section.

5.2 METHODOLOGY

5.2.1 Small and medium wind systems

The methodology used to forecast small and medium wind systems relies on several key assumptions:

1) For IPL, these systems will be installed in a net metering arrangement with owners being able to offset retail electricity rates.
2) There is a large technical potential with market growth during the forecast period not limited by the electrical distribution system capacity or wind resource availability.
3) Growth patterns through 2016 will reflect the presence of the federal ITC.
4) Existing capacity is maintained or replaced at the same level of performance, with the forecast reflecting incremental additions of small and medium wind capacity.
5) Demand for small wind turbines will reflect national trends that are reflected in the Energy Information Administration 2013 Annual Energy Outlook.

6) Energy production estimates can modeled using single turbines as examples of small and medium wind systems.

To model energy production from small wind systems, we used two models of existing turbines to represent prototypical wind turbines. A Bergey Excel 10 turbine (10 kW) was used to model small turbines, while an Endurance E3120 (50 kW) was used to model medium-scale turbines. Actual kWh performance for small and medium wind was unavailable and complicated by the net metering arrangement in which a portion of the energy may never be recorded by an electricity meter. Although a wide range of possible turbine capacities and performances can be expected for each of these size categories, these turbines serve to represent the kWh per kW performance and provide a reasonable production estimate.

Small and medium wind turbines are developed based on system owner's geographic limits, and are not optimized by the ideal location setting of utility-scale wind farms. Put another way, the owners are not able to select their wind resource, but must take advantage of the wind resource available to them. While customers are less likely to make a purchase decision with a poor wind resource, small and medium wind owners must be willing to accept the compromises of their property and siting options' impacts to their turbines. We reviewed the Iowa Wind map from the National Renewable Energy Laboratory (NREL)[13] and selected a general 80-meter average wind speed resource from the maps to broadly represent an average small and medium wind resource from which the turbine specific production estimates could be developed.

For both turbine models, an assumed 7.25 m/s average wind speed at 80 meters was used to capture average performance. For any given installation, the wind resource will be different. The selection of the 7.25 m/s wind speed was based on middle-quality wind resources found in southeastern Minnesota and north central to northeastern Iowa. The production estimates for each system were based on integrating the manufacturer's power curve across a wind frequency distribution using MS-Excel's® Weibull equation and derating the output. This production method is standard for small and medium wind turbine site assessments and described in many industry publications. Table 5-2 describes the key wind resource and production modeling assumptions and results for each turbine.

[13] http://www.nrel.gov/gis/wind.html.

Table 5-2. Wind Resource and Production Modeling for Small and Medium Wind Turbines

Modeling Factor	10 kW Turbine	50 kW Turbine
Manufacturer	Bergey	Endurance
Model	Excel 10	E3120
80 m/s wind speed	7.25	7.25
Turbine hub height	37 meters (120 feet)	43 meters (140 feet)
Wind shear alpha	0.30	0.30
Weibull k factor	2.3	2.3
Ground elevation above sea level	450 meters	450 meters
Power curve source	SWCC[14] certification	SWCC test results
Turbine derate[15]	25 percent	15 percent
Annual average kWh	13,311 kWh	139,449
kWh/kW	1,331 kWh/kW	2,789 kWh/kW
Overnight capital cost[16]	$65,000	$375,000
Overnight capital cost per first year kWh	$4.88	$2.69
O&M ($/kW–yr)[17]	$10.00	$22.50

Our forecasting method for small and medium turbines does not rely directly on the economics of the technology. Rather, the forecasting method considers the market behavior in the past six years, adjusts for the effect of utility incentive removal, and then relies on the Energy Information Administration's (EIA) 2013 national forecast for *solar photovoltaic* growth for 2017–2029 for non-marketed solar energy.

The EIA's non-marketed wind forecast showed zero growth for wind following the end of the federal ITC. Given the IPL market's growth in small and medium wind systems prior to federal ITC availability, an assumption of zero growth in the years following the ITC appears unreasonable for the IPL territory. In using the non-marketed annual cumulative growth rate of non-marketed solar photovoltaics from the EIA, the IPL forecast assumes a growth rate equal to that of photovoltaics. The economics of small and medium wind are similar to solar electric systems, with Iowa's strong history with wind development suggesting that the market for small and medium wind energy will be different for Iowa and IPL than may be the case

[14] Small Wind Certification Council independent test results. http://www.smallwindcertification.org/.
[15] A turbine derate is used to capture losses from turbulence, yawing, electrical conversion efficiency, blade soiling and wear, and maintenance downtime. The 25 percent derate for the Bergey is meant to capture a general condition of small turbines with more compromised sites, potentially shorter towers, and non-certified turbine performance. It is not a reflection of the Bergey Excel 10 turbine. The 15 percent derate for the Endurance turbine reflects industry standard turbine derates and is meant to reflect fewer siting compromises due to the taller tower and general quality of the medium turbine wind market.
[16] Personal communications with Bergey and Endurance Windpower, December 2013.
[17] http://www.windpoweringamerica.gov/pdfs/2012_annual_distributed_wind_market_report.pdf.

nationally. For the high policy case, the EIA's non-marketed solar photovoltaic growth is also used as a proxy for small and medium wind, just as in the base forecast. In the case of the low policy support scenario, the base case forecast annual growth is reduced by 75 percent starting in 2017, reflecting an impact of reduced interconnections in line with that experienced by Wisconsin Public Service from 2010 to 2013 and discussed in the report section describing the policy scenarios.

Table 5-3. Forecasted Growth Rates for Small and Medium Wind Capacity, Key Time Periods

Time Period	Annual Cumulative Growth Rate	Assumptions
2014 (all scenarios)	6.1 percent small residential 6.3 percent small nonresidential 1.9 percent medium wind	Same as 2013 actual annual cumulative growth
2015 and 2016 (all scenarios)	9.3 percent small residential 13.4 percent small nonresidential 9.0 percent medium wind	½ the average annual cumulative growth from 2009–2012
Base Case 2017–2029	Small residential – 1.1 percent on average Small nonresidential – 2.4 percent on average Medium wind – 2.4 percent on average	Assumes EIA reference case solar growth rate for residential and nonresidential customers
High-Policy Case 2017–2029	Small residential – 5.9 percent on average Small nonresidential – 3.6 percent on average Medium wind – 3.6 percent on average	Assumes EIA no sunset solar growth rate for residential and nonresidential customers
Low-Policy Case	25 percent of base case growth rates	Based on base case annual cumulative growth rates

5.2.2 MW-Class wind systems

Distributed generation using MW-class wind systems was modeled using two core assumptions:

1) The energy performance experienced by IPL from past installations, on a kWh/kW basis, represents future performance.

2) The logic for the market to make such investments is based on a profit motive reflected in the cost of the energy relative to its market value.

A. Performance modeling

IPL provided PPA contract data to Tetra Tech that described the 2012 energy production and capacity of MW-class wind projects. Our analysis considered installations of approximately 500 kW to 10 MW to understand the energy production and capacity factors of MW-class wind. Such systems have been installed since 2003 and encompass development scopes from single turbines up to eight turbines. We reviewed the production data, which detail energy production totals for each month of the year. Additionally, we reviewed Mason City, IA weather data to understand whether 2012 was an unusual year for higher or lower than average wind speeds for the region.

Based on Weather Underground data, 2012 appears to be a near average year for wind speeds in Mason City, IA.[18] Daily average wind speeds in 2012 averaged to 10.64 mph at the airport. This compares to a long-term annual wind speed average (1995–2013) of 10.68 mph, indicating that 2012 average wind speeds were 99.6 percent of the long-term average.

We reviewed the energy production and calculated capacity factors for distributed generation MW-class turbines that operated for all of 2012. These turbines exhibited a capacity-weighted capacity factor of 34.1 percent.

Also in 2012, 20 MW of MW-class DG wind became operational. These turbines largely consisted of 1.6 MW GE turbines, which represent an example of modern utility-scale wind technology and may differ in performance from the mix of turbines previously installed. To understand how this large addition of capacity (38 percent) would influence the overall capacity factor of the IPL MW-class distributed wind market, we analyzed the relative performance from December 2012, the only month when all of the additional turbines were operational and compared the results to the December production from turbines that operated for the full year. In December 2012, the new-in-2012 turbines exhibited a capacity factor of 40.1 percent, whereas the previously installed turbines exhibited a December 2012 capacity factor of 33.0 percent, for a ratio of 1.22:1. We assumed that the turbines new in 2012 would consistently provide a capacity factor 22 percent higher than the previously installed DG MW-class turbines.

We estimated the annual capacity factor of the new-to-2012 turbines by multiplying the annual capacity factor of the previously operating turbines by 1.22 (the December capacity factor ratio). The result is that the 20 MW of turbines installed in 2012 are estimated to have an annual average capacity factor of 41.5 percent. For the entire fleet of MW-class distributed wind systems, the capacity-weighted capacity factor is 36.1 percent.

Applying the 36.1 percent capacity factor to the installed capacity of 72,510 kW results in a total average of 229,302 MWh of production per year. On a kWh/kW basis, this comes to 3,162 kWh per kW of MW-class distributed wind. This performance factor is used to estimate the annual MWh of the forecasted MW installations.

[18] www.wunderground.com.

B. Economic modeling

The economic modeling assumed that financial returns drive investment decisions for distributed wind technology using MW-class turbines. Thus, past systems are assumed to have been installed in a situation that exhibited favorable economics. To forecast future additions of MW-class distributed wind technology we developed an economic model to understand when, if, and in what policy context distributed wind may become cost effective in the forecast period.

The base economic model considers the levelized cost of energy (LCOE) from MW-class turbines compared to the assumed levelized value of a wind power purchase agreement (PPA). For each year of the forecast period a LCOE for MW-class wind and a PPA value were developed, allowing for a judgment of whether MW-class wind would be attractive to develop in that year. In years where the PPA value exceeds the LCOE, we assume investments would occur, with a two-year lag to reflect development timelines. Table 5-4 describes the assumptions of the LCOE analysis.

Table 5-4. MW-class DG Wind LCOE Assumptions, Base and Low-Policy Cases

LCOE Factor	LCOE Metric	Notes
Overnight capital cost ($/kW)	$2,500 per kW[19]	Held constant in nominal terms during the forecast period[20]
O&M Cost ($/kW-yr)	$35[21]	Inflates by general rate of inflation
Marginal tax rate	35 percent	Assumes a tax paying entity with tax liability
MACRS NPV factor	0.288	NPV factor of 5 year MACRS depreciation tax effect
Salvage value	NPV of 25 percent of capacity cost	Assumes 20-year life with 15-year PPA
Discount rate	7.44 percent	Utility WACC provided by IPL
Inflation rate	2.00 percent	General rate of inflation 2014–2029
System kW	3,000 kW	Used to model energy production, O&M expenses and capital cost
Annual system kWh	9,487,080 kWh	Annual energy production from representative system (3,000 kW)

[19] Based on a review of community wind case studies from Bolinger, Mark (2011). "Community Wind: Once Again Pushing the Envelope of Project Finance." Lawrence Berkeley National Labs, January 2011.

[20] Prices for MW-class wind capacity have varied over the years, with small developments showing wide ranges. According to NREL data, costs have declined since a peak in 2010 and can be expected to further decline. We also speculate that community wind developments may become more cost effective as demand for utility scale investments begins to taper and more turbine capacity is available, with the market also finding efficiencies in this size range of development.

[21] Tegen, S (et al 2010). "2010 Cost of Wind Energy Review" National Renewable Energy Laboratory, April 2012. Rounded to $35 to account for inflation.

All three scenarios result in the same LCOE. As the federal PTC and ITC have expired, no incentives, other than the five-year Modified Accelerated Cost Recovery System (MACRS) depreciation schedule, have an effect on the LCOE. It is possible that REAP could result in awards for projects that would lower the LCOE. Additionally, New Market Tax Credits might be leveraged to assist with financing. These incentives could lower the LCOE, but are only applicable to specific projects and situations, not a general market condition from which generalized forecasts can be made. The LCOE for each year in the forecast period are shown in Table 5-5.

Table 5-5. LCOE of MW-Class Distributed Wind Systems 2014–2029

[TRADE SECRET DATA BEGINS [TRADE SECRET DATA BEGINS

Year	LCOE ($/MWh)	Year	LCOE ($/MWh)
2014	[redacted]	2022	[redacted]
2015	[redacted]	2023	[redacted]
2016	[redacted]	2024	[redacted]
2017	[redacted]	2025	[redacted]
2018	[redacted]	2026	[redacted]
2019	[redacted]	2027	[redacted]
2020	[redacted]	2028	[redacted]
2021	[redacted]	2029	[redacted]

TRADE SECRET DATA ENDS] TRADE SECRET DATA ENDS]

To estimate the PPA value against which the LCOE would be compared, we developed a PPA forecast using wholesale price forecasts for Midcontinent Independent System Operator (MISO) on-peak and off-peak values developed for Alliant Energy by Wood Mackenzie. As wind energy is a variable energy source, we further adjusted the Wood Mackenzie wholesale prices by the ratio of Alliant Energy wind avoided cost values for 2013 as filed with the Federal Energy Regulatory Commission (FERC). [TRADE SECRET DATA BEGINS [redacted]

[redacted]

TRADE SECRET DATA ENDS]

[22] TMY3 data represent a "typical meteorological year" and are developed and distributed by the National Renewable Energy Laboratory. http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2005/tmy3/.

[TRADE SECRET DATA BEGINS

[redacted]

TRADE SECRET DATA ENDS]

The resulting PPA values for the base case and low-policy scenario are presented in Table 5-6.

Table 5-6. MW-class Distributed Wind Estimated PPA Values, Base and Low Policy Cases

[TRADE SECRET DATA BEGINS [TRADE SECRET DATA BEGINS

Year	LCOE ($/MWh)	Year	LCOE ($/MWh)
2014	[redacted]	2022	[redacted]
2015	[redacted]	2023	[redacted]
2016	[redacted]	2024	[redacted]
2017	[redacted]	2025	[redacted]
2018	[redacted]	2026	[redacted]
2019	[redacted]	2027	[redacted]
2020	[redacted]	2028	[redacted]
2021	[redacted]	2029	[redacted]

TRADE SECRET DATA ENDS]

TRADE SECRET DATA ENDS]

For the high policy support scenario, a $21 per metric ton of carbon is added to the value for the PPA. Using the most recent EPA eGRID emissions rates, the $21 per metric ton of carbon adds $20.27 per MWh to the PPA value. We assume the $21 per metric ton of carbon will be instituted in 2017. For PPAs that occur in the high policy support scenario prior to 2017, the effect of the carbon value is incorporated into the PPA as part of the levelized NPV of the avoided energy costs, which would not include the value of carbon for the years 2014–2016. Only in 2017 and later is the value of carbon applied to all MWhs of energy produced. Table 5-7 shows the effect of the carbon value on PPA rates for the high policy support scenario.

Table 5-7. MW-class Distributed Wind Estimated PPA Values, High Policy Case

[TRADE SECRET DATA BEGINS [TRADE SECRET DATA BEGINS

Year	LCOE ($/MWh)	Year	LCOE ($/MWh)
2014	[redacted]	2022	[redacted]
2015	[redacted]	2023	[redacted]
2016	[redacted]	2024	[redacted]
2017	[redacted]	2025	[redacted]
2018	[redacted]	2026	[redacted]
2019	[redacted]	2027	[redacted]
2020	[redacted]	2028	[redacted]
2021	[redacted]	2029	[redacted]

TRADE SECRET DATA ENDS] TRADE SECRET DATA ENDS]

In comparing the PPA values to the LCOE estimate, the reference case and low policy support case show a positive economic return starting in 2025 for MW-class distributed wind systems. In the high policy support case, investments are shown to be cost effective starting in 2015.

C. *Forecast modeling*

The forecast for MW-class distributed wind energy is based on a review of the existing capacity and growth from 2008–2013. During this period, some years saw installations and other years saw no installations. On average, 4,300 MW were installed per year. Under the assumption that these projects were investment-grade for the owners, we assumed that the 2008–2013 capacity additions reflect the IPL service territory's ability to leverage market capital and industry capacity for MW-class distributed wind systems. Thus, for a given year, on average, the service territory has the ability to invest in and install 4,300 MW of MW-class distributed wind.

As these developments are driven by economic considerations, based on economic growth, future years would reflect greater capital availability for developing such projects. To estimate the potential capacity that could be installed in any year, our forecast method develops nominal capital availability on a MW basis by inflating the 4,300 MW per year by the rate of forecasted real economic growth and inflation rate.[23] The result is an estimate for each year of the IPL service territory's potential installation of MW-class distributed wind systems.

Using the potential capacity to install MW-class distributed wind, those years for which projects would be cost effective are identified for each scenario and assigned the potential capacity value for that year. This method assumes there are no technical limitations to interconnecting the systems in any year or by capacity. Table 5-8 describes the annual potential capacity of MW-class wind additions for a given year and the year's determination for cost effectiveness in each scenario.

[23] Based on Wood Mackenzie data and assumes 2 percent inflation and 2.6 percent real economic growth.

For modeling the summer peak kW contribution of wind energy, a rate of 14.1 percent of generator capacity is used. This is based on the MISO average wind energy contribution to summer peak.[24]

Table 5-8. MW-Class Wind Potential Capacity and Scenario Cost Effectiveness

Year	Potential MW	Pass Base or Low-Policy Scenario	Pass High Policy Scenario
2014	4,500	No	No
2015	4,709	No	Yes
2016	4,928	No	Yes
2017	5,158	No	Yes
2018	5,398	No	Yes
2019	5,649	No	Yes
2020	5,912	No	Yes
2021	6,187	No	Yes
2022	6,474	No	Yes
2023	6,776	No	Yes
2024	7,091	Yes[25]	Yes
2025	7,421	Yes	Yes
2026	7,766	Yes	Yes
2027	8,127	Yes	Yes
2028	8,505	Yes	Yes
2029	8,901	Yes	Yes

5.3 RESULTS

The forecast modeling of small and medium wind turbines along with MW-class wind turbines results in the incremental capacity additions shown in the following tables for each scenario and in aggregate for all wind. We assume that any existing capacity will be replaced as it wears out or is repowered. The base case and low-policy case scenarios reflect cost effectiveness starting in 2025, with a two-year lag before locations are developed and turbines are installed and operational. In the high policy case, turbines will be cost effective due to the impact of the carbon tax on PPA rates, with the two-year lag resulting in turbines being installed and operational in 2017.

[24] https://www.misoenergy.org/Library/Repository/Study/LOLE/2014%20Wind%20Capacity%20Report.pdf.

[25] Although 2024 shows MW-class wind being cost effective, the effect of that year is discounted in the forecast due to the very low cost effectiveness difference of less than $1 per MWh.

Table 5-9. Base Case Distributed Wind IPL Forecast 2014–2029

Year	Small MW	Small MWh	Medium MW	Medium MWh	MW-Class MW	MW-Class MWh	Total MW	Total Summer Peak MW	Total MWh
2014	0.144	191	0.056	156	0	0	0.2	0.0	347
2015	0.449	598	0.325	908	0	0	0.8	0.1	1,506
2016	0.794	1,057	0.619	1,726	0	0	1.4	0.2	2,783
2017	0.829	1,104	0.667	1,860	0	0	1.5	0.2	2,964
2018	0.872	1,160	0.724	2,020	0	0	1.6	0.2	3,180
2019	0.920	1,225	0.789	2,201	0	0	1.7	0.2	3,426
2020	0.975	1,297	0.860	2,399	0	0	1.8	0.3	3,696
2021	1.0	1,378	0.938	2,616	0	0	2.0	0.3	3,993
2022	1.1	1,464	1.0	2,852	0	0	2.1	0.3	4,316
2023	1.2	1,565	1.1	3,127	0	0	2.3	0.3	4,692
2024	1.3	1,674	1.2	3,425	0	0	2.5	0.4	5,099
2025	1.3	1,794	1.3	3,752	0	0	2.7	0.4	5,546
2026	1.4	1,915	1.5	4,082	0	0	2.9	0.4	5,997
2027	1.5	2,050	1.6	4,453	8.1	25,701	11.3	1.6	32,204
2028	1.7	2,203	1.7	4,863	16.6	52,597	20.0	2.8	59,663
2029	1.8	2,357	1.9	5,279	25.5	80,745	29.2	4.1	88,381

Table 5-10. Low Policy Case Distributed Wind IPL Forecast 2014–2029

Year	Small MW	Small MWh	Medium MW	Medium MWh	MW-Class MW	MW-Class MWh	Total MW	Total MWh
2014	0.144	191	0.056	156	0	0	0.2	347
2015	0.449	598	0.325	908	0	0	0.8	1,506
2016	0.794	1,057	0.619	1,726	0	0	1.4	2,783
2017	0.803	1,069	0.631	1,760	0	0	1.4	2,828
2018	0.813	1,083	0.645	1,800	0	0	1.5	2,882
2019	0.825	1,099	0.661	1,844	0	0	1.5	2,942
2020	0.838	1,116	0.678	1,892	0	0	1.5	3,008
2021	0.853	1,135	0.697	1,943	0	0	1.5	3,078
2022	0.868	1,156	0.717	1,998	0	0	1.6	3,154
2023	0.886	1,179	0.739	2,062	0	0	1.6	3,241
2024	0.904	1,204	0.764	2,129	0	0	1.7	3,333
2025	0.925	1,231	0.790	2,202	0	0	1.7	3,433
2026	0.944	1,257	0.815	2,274	0	0	1.8	3,531
2027	0.966	1,286	0.844	2,353	8.1	25,701	9.9	29,340
2028	0.991	1,319	0.874	2,438	16.6	52,597	18.5	56,354
2029	1.0	1,350	0.905	2,523	25.5	80,745	27.5	84,618

Table 5-11. High Policy Case Distributed Wind IPL Forecast 2014–2029

Year	Small MW	Small MWh	Medium MW	Medium MWh	MW-Class MW	MW-Class MWh	Total MW	Total MWh
2014	0.144	191	0.056	156	0	0	0.2	347
2015	0.449	598	0.325	908	0	0	0.8	1,506
2016	0.794	1,057	0.619	1726	0	0	1.4	2,783
2017	0.904	1,203	0.685	1910	5.2	16,311	6.7	19,424
2018	1.0	1,365	0.775	2163	10.6	33,380	12.4	36,908
2019	1.2	1,543	0.888	2477	16.2	51,243	18.3	55,263
2020	1.3	1,762	1.0	2888	22.1	69,938	24.5	74,588
2021	1.5	1,984	1.2	3321	28.3	89,502	31.0	94,806
2022	1.7	2,214	1.4	3799	34.8	109,976	37.8	115,989
2023	1.8	2,453	1.5	4305	41.6	131,403	44.9	138,160
2024	2.0	2,691	1.7	4819	48.6	153,826	52.4	161,336
2025	2.2	2,935	1.9	5356	56.1	177,293	60.2	185,584
2026	2.4	3,176	2.1	5890	63.8	201,851	68.3	210,917
2027	2.6	3,416	2.3	6433	72.0	227,552	76.8	237,402
2028	2.7	3,654	2.5	6975	80.5	254,448	85.7	265,077
2029	2.9	3,896	2.7	7535	89.4	282,596	95.0	294,026

6. BIOGAS

6.1 TECHNOLOGY OVERVIEW

Over the past decade biogas and power generation technologies have advanced considerably, though the growth of power generating installations has been limited in the US. Both Iowa and Minnesota have significant biomass resources to support biogas generation, yet neither have experienced large amounts of new biogas and power generation in the last decade. According to the AgSTAR database, a total of 3,330 kW of farm-based biogas to power systems exist in Iowa, with Minnesota hosting 6,845 kW. Of that capacity, the IPL system is shown to be hosting 130 kW[26]. Alliant Energy indicated that no landfill gas projects were currently interconnected with the IPL system.

There are three primary types of biogas based distributed generation technologies applicable to the IPL service area: (1) landfill gas to energy, (2) wastewater treatment plants (municipal and industrial) producing biogas through anaerobic digestion to energy, and (3) anaerobic digestion (AD) producing biogas to energy at farms with a high density of animals. In general, these types of systems are relatively small in scope with potential generation capacities ranging from the hundreds of kilowatts to approximately 2 megawatts, enabling and interconnection at the distribution level.

To generate electricity, biogas systems typically combust the biogas in internal combustion engines. Such systems are reliant on a steady supply of biomass, with the conversion technology located in close proximity to the source of biogas. In the case of manure and especially wastewater treatment plants, transporting the material over long stretches is financially burdensome due to high water content. Similarly, biogas from landfills requires the presence of the landfill, making material movement impractical. The biogas itself can be moved offsite, but requires transportation infrastructure to do so. As a result, projects typically generate power at the source of the biomass and biogas creation.

Projects involving landfills and wastewater treatment plants typically utilize facilities having a useful life of many decades, often more than 50 years. In contrast, farms may open, close, expand, or contract, leading to different planning horizons for the system owners. In general, biogas energy projects are developed based on investment criteria driven mostly by the value proposition of energy sales, but can be influenced by environmental regulations faced by the owner.

For purposes of forecasting additional biogas energy installations in the IPL service territory, our analysis divided the biogas market into three segments, capturing the significant differences in technology and project types. The analysis assumes that with respect to investment decisions made by owners, the economies of scale set a lower limit on the reasonable size of facilities.

In general, the capital cost of a biogas-to-power system is substantial. In the case of landfills and wastewater treatment plants, much of the capital cost is part of the existing facility, with

[26] According to Alliant Energy, this system is not currently producing electricity (K. King, personal communication, January 22, 2014). Additionally the AgSTAR data does not include a recently interconnected 939 kW project (in September 2013) that is located in the IPL territory.

incremental costs related to biogas capture, cleanup, power generation, and grid interconnection. In contrast, for farm biogas, there are typically no existing biogas generation facilities, so the owner must invest in anaerobic digestion and support facilities, in addition to generation and interconnect requirements.

Alliant Energy provided data describing the current system interconnections of distributed generation technologies. For biogas, only farm biogas had existing systems currently interconnected to the IPL system and providing energy. No landfill gas or wastewater treatment plants were shown to be currently interconnected. Table 6-1 illustrates the installed biogas capacity in the IPL service territory at the end of 2013.

Table 6-1. Biogas Installed Capacity IPL Service Territory[27]

Technology Type	2013 EOY Installed Capacity	Percent of Operating Biogas Capacity	Total Capacity Growth 2007–2013
Landfill Gas	0 kW	0%	0%
AD Biogas (WWTP)	0 kW	0%	0%
AD Biogas (Farms)	939 kW	100%	100%
Total IPL DG Biogas	939 kW	100%	100%

During the 2008–2013 timeframe, several policies and market forces influenced the biogas-to-energy market. These included the federal PTC, the federal ITC, the REAP program of the United States Department of Agriculture (USDA), and state level efforts to encourage market participation. In many cases, investors, owners and developers sought to capture the value of these incentives to augment the cost of environmental compliance costs. Despite these efforts and incentives, it appears they have had limited impact in stimulating projects in the IPL service territory.

All biogas-to-energy categories face stiff economic and policy challenges for the 2014–2029 forecast period. The federal PTC and ITC programs expired at the end of 2013, with no indication these tax programs will be renewed.

For some select combined heat and power (CHP) systems and technologies, which includes biogas, a federal ITC remains in effect until the end of 2016. With the recent passage of the 2014 Farm Bill, REAP was renewed for an additional five years[28]. The REAP grants and loan guarantees were funded with a blend of mandatory and discretionary programs that still must pass through federal budget authorization. REAP funds are awarded in a competitive process that has historically proven to be highly competitive. Our experience and review of past REAP awards suggests that the ratio of project applications to awards is approximately 10:1. As a result, REAP is not planned to be of significance to the point of driving forecast numbers, though it is possible that individual projects may ultimately receive REAP funds.

[27] Based on IPL provided data. We note that there is a discrepancy with farm biogas data between the American Biogas Council data and IPL data, which does not show the 939 kW system and does show a 130 kW system. In discussion with Alliant Energy, it was explained that the 130 kW system does exist, but is not currently producing power. The 939 kW system was interconnected in September 2013 and had not been added to the American Biogas Council data as of January 2013.

[28] Agricultural Act of 2014.

The farm and wastewater treatment plant biogas industry is relatively small and maturing. When combined with the significant additional capital requirements involved in installing projects, growth may be limited in this segment, though IPL does exhibit potential for additional growth in the forecast period.

6.2 METHODOLOGY

The methodology used to forecast biogas to power generation relies on several key assumptions:

1) These systems will be installed as an investment decision to supply power to the grid with owners paid for electricity delivered based on a long-term power purchase agreement.
2) There is technical potential for market growth during the forecast period not limited by the electrical distribution system capacity or biomass resource availability.
3) Growth patterns through 2016 will reflect the presence of the federal ITC for select technologies.
4) Existing capacity is maintained or replaced at the same level of performance with the forecast reflecting incremental additions of biogas to energy capacity.

To model biogas to power generation we analyzed the biogas potential in three technology segments and sized generator capacity based on available internal combustion engine (ICE) generator sets (gen sets) commonly used by the industry. For landfills and wastewater treatment plants, the biogas potential was estimated by considering specific facilities in the IPL service territory. For farm-based biogas, likely farm potential was developed using the USDA 2007 Census of Agriculture[29], the most recent version of the Census.[30]. In all cases the systems are assumed to utilize biogas generation, collection, and cleanup technologies such that the biogas is useable in commercially available ICE gen sets.

In the landfill gas category we used the US EPA Landfill Methane Outreach Program (LMOP) database to determine the location, size, and longevity of landfills in the IPL service territory. This information was validated through direct contact with the landfill owner or operators. With this information, we applied the US EPA Landfill Gas Emissions Model, Version 3.02 (LandGEM) to the scenario for each landfill. The output of this model forecasts the amount of methane as gas generated over time as well as quantities of carbon dioxide avoided emission that could be eligible for carbon credits and the methane equivalent CO_2 reduction.

In the wastewater treatment biogas category, we used the American Biogas Council (ABC) wastewater treatment plant inventory database to establish an initial list of facilities in Iowa and Minnesota. This list was crosschecked by Alliant staff identifying those facilities operating in the IPL service territory. Based on industry standards for biogas potential per million gallons per day of sewage flow rate, we established the potential biogas generation rate.

---

[29] United States Department of Agriculture, 2007 Census of Agriculture, Summary and State Data, Washington, DC.

[30] Preliminary results of the 2012 Census of Agriculture were released in late February 2014. The data are incomplete and not yet suitable to use in this analysis; the full database is anticipated to be released in May 2014 according to the USDA 2012 Census of Agriculture website on Feb, 27, 2014.

Based on this review, we identified four ICE genset sizes: 64 kW (one potential plant), 100 kW (two potential plants), 180 kW (two potential plants) and 250 kW (one potential plant). These systems were the basis for generating potential WWTP biogas-to-power capacity in the IPL service area.

In the farm biogas category, the 2007 USDA Census of Agriculture to determine the county level location and size of dairy, swine, and poultry farms in counties that are served by IPL. We referred to the US EPA AgSTAR document "Market Opportunities for Biogas Recovery Systems at US Livestock Facilities, 2011" for various technical criteria, including minimum feasible size of livestock farm based on animal count. Combining this information allowed the calculation of generating capacity based on three sizes of ICE gensets—180 kW, 329 kW, and 400 kW at dairy and swine farms in the IPL territory.

Candidate farms for installing biogas recovery systems were identified using the characteristics described in Table 6-2. These characteristics were selected based on AgSTAR evaluations of the technical and economic performance of successful digester systems operating on commercial scale swine and dairy farms. AgSTAR did not conduct a site-specific cost analysis; specific sites conditions, such as energy contracts, environmental permitting requirements, and other variables that affect the economic feasibility of projects.[31]

Table 6-2. Typical Characteristics where Biogas Recovery Systems May be Profitable

Animal Type	Manure Management Method[32]	Size of Operation
Dairy	Flushed or scraped freestall barns and open lots	≥ 500 head
Swine	Houses with flush, pit recharge, or pull-plug pit systems[33]	≥ 2,000 head

The Ag Census data were analyzed for the counties in Iowa and Minnesota served by IPL. From these data we developed the number of dairy and swine farms as potential candidates for biogas systems. The minimum criteria were farms having at least 500 head for dairy or at least 5,000 head for swine. A limitation of the Ag Census data is the lack specific location coordinates for the farms. As a result, it is not possible to accurately determine whether a candidate farm in a given county is within or near the IPL service area. We estimated that 20 percent of the potential candidate farms could be connected to IPL. The 20 percent factor reflects the general observation that most farms are located in rural areas away from population centers, with the more rural areas served by rural electrical cooperative utilities. The 20 percent factor was applied to all potential candidate farms across the IPL service

[31] US EPA AgSTAR, Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities, November 2011, Washington DC.

[32] Total solids content <15% and at least weekly manure collection.

[33] Biogas systems are not currently used at swine confinement houses with deep pits. Deep pits under slatted floors are commonly used in cool regions such as the upper Midwest. Deep pit systems would need to be modified to remove manure more frequently before a biogas capture and utilization system could be installed. The feasibility of conversion depends on the value of the biogas produced relative to the capital investment required. Estimates in this report assume that deep pit operations with more than 5,000 head could use biogas systems by converting to at least weekly manure removal.

territory, achieving the final result of total number of potential candidate farms. Table 6-3 summarizes these data.

Table 6-3. Summary of Iowa and Minnesota Potential Candidate Farm Data

Number of Farms	Average Head Count	Total Head Count	Number of Farms	IPL Candidate Farms[34]
Iowa Swine	6,554	570,185	87	17
Iowa Dairy	665	2,660	4	1
Minnesota Swine	5,337	875,253	164	33
Minnesota Dairy	811	13,785	17	3

Modeling was adjusted for a high-policy support case, reflecting a carbon tax of $21 per metric ton CO_2 removed, while the base and low-policy scenarios assumes the PTC and ITC are not renewed.

6.2.1 Economic modeling

In all biogas technology categories, we assumed that financial returns drive investment decisions. To forecast future additions of biogas generating capacity, we developed an economic model to understand when, if, and in which scenarios biogas generation may become cost effective during the forecast period. Although some categories of biogas systems, particularly farm based, may derive revenue from other components of the system (solid fertilizer or compost), our experience finds that these sources of revenue are not enduring, contractible, or investment grade and do not influence investment decisions. Therefore, no revenue beyond the sale of energy or avoided carbon (in the high policy case) was factored into the cost model used for this analysis.

In all categories, the basic economic model considers the levelized cost of energy (LCOE) compared to the estimated levelized value of a biogas generation power purchase agreement (PPA). For each year of the forecast period an LCOE for biogas and an estimated PPA value were developed, allowing for estimating whether biogas generation would be attractive to develop in a given year. In years where the PPA exceeds the LCOE, we assume investments may occur. Table 6-4 through Table 6-6 describes the assumptions of the LCOE analysis.

[34] We assumed that 20 percent of each county's candidate farms are served by IPL.

Table 6-4. Biogas Landfill LCOE Assumptions

Landfill LCOE Factor	LCOE Metric	Notes
Overnight Capital Cost ($/kW)	$2,320	US EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, December 2008; 2G Cenergy Power Systems Technologies Inc., Biogas CHP Cogeneration Module Product Line Data Sheet, 04/01/2013
O&M Cost ($/kW-yr)	$130	US EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, December 2008.
Marginal Tax Rate	35%	assumed
MACRS NPV factor	0.156	NPV factor of depreciation tax effect, net of gas collection system
Salvage value	$0	Useful life assumed to be 15 years
Discount rate	7.44	Utility weighted average cost of capital provided by IPL
Inflation rate	2.0 percent	General rate of inflation 2014–2029
System kW	2,000	assumed
Annual system MWh	139,706	Assumed 90 percent capacity factor

Table 6-5. Biogas Wastewater Treatment Plant (WWTP) LCOE Assumptions

WWTP LCOE Factor	LCOE Metric				Notes
System kW	64	100	180	250	
Overnight Capital Cost ($/kW)	$13,632	$9,804	$7,073	$6,211	US EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, December 2008; 2G Cenergy Power Systems Technologies Inc., Biogas CHP Cogeneration Module Product Line Data Sheet, 04/01/2013
Annual system MWh	4,471	6,985	12,574	17,463	Assumes 90 percent capacity factor
O&M Cost ($/kW-yr)	$126				US EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, December 2008
Marginal Tax Rate	35%				assumed
MACRS NPV factor	0.288				NPV factor of the 5 year MACRS depreciation schedule
Salvage value	$0				Useful life assumed to be 15 years
Discount rate	7.44				Utility weighted average cost of capital provided by IPL
Inflation rate	2.0 percent				General rate of inflation 2014-2029

Table 6-6. Biogas Farm LCOE Assumptions

Farm LCOE Factor	LCOE Metric			Notes
System kW	180	329	400	
Overnight Capital Cost ($/kW)	$6,024	$4,115	$4,425	US EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, December 2008; 2G Cenergy Power Systems Technologies Inc., Biogas CHP Cogeneration Module Product Line Data Sheet, 04/01/2013
Annual system MWh	12,574	22,982	27,941	Assumes 90 percent capacity factor
O&M Cost ($/kW-yr)	$120	$112	$128	US EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, December 2008
Marginal Tax Rate	35%			assumed
MACRS NPV factor	0.288			NPV factor of the 5-year MACRS depreciation schedule
Salvage value	$0			Useful life assumed to be 15 years
Discount rate	7.44			Utility weighted average cost of capital provided by IPL
Inflation rate	2.0 percent			General rate of inflation 2014–2029

All scenarios resulted in different LCOEs for each technology during the forecast period. Table 6-7 presents the LCOE for each technology and year of the forecast period.

Table 6-7. Biogas Summary Table—LCOE ($/MWh)

	Landfill	WWTP				Farm		
kW	2,000	64	100	180	250	180	329	400
2014	$72.94	$131.02	$100.55	$76.37	$70.47	$78.80	$58.26	$63.64
2015	$74.40	$133.54	$102.50	$77.85	$71.83	$80.38	$59.43	$64.92
2016	$75.56	$136.12	$104.49	$79.35	$73.22	$81.99	$60.62	$66.21
2017	$76.75	$138.75	$106.52	$80.89	$74.63	$83.62	$61.83	$67.54
2018	$77.96	$141.42	$108.59	$82.46	$76.08	$85.30	$63.07	$68.89
2019	$79.19	$144.16	$110.70	$84.05	$77.55	$87.00	$64.33	$70.27
2020	$80.45	$146.94	$112.85	$85.68	$79.05	$88.74	$65.61	$71.67
2021	$81.73	$149.78	$115.05	$87.35	$80.58	$90.52	$66.93	$73.11
2022	$83.04	$152.68	$117.28	$89.04	$82.14	$92.33	$68.27	$74.57
2023	$84.38	$155.64	$119.57	$90.77	$83.74	$94.18	$69.63	$76.06
2024	$85.74	$158.66	$121.90	$92.53	$85.36	$96.06	$71.02	$77.58
2025	$87.13	$161.73	$124.27	$94.33	$87.02	$97.98	$72.44	$79.13
2026	$88.55	$164.87	$126.70	$96.17	$88.71	$99.94	$73.89	$80.71
2027	$89.99	$168.07	$129.17	$98.04	$90.44	$101.94	$75.37	$82.33
2028	$91.47	$171.34	$131.69	$99.95	$92.19	$103.98	$76.88	$83.98
2029	$92.97	$174.67	$134.26	$101.90	$93.99	$106.06	$78.42	$85.66

To estimate the PPA value against which the LCOE is compared, we developed an estimated PPA forecast using wholesale price forecasts for MISO on peak and off-peak values created for Alliant Energy by Wood Mackenzie. Additionally, a capacity credit value is added to the PPA at $11.90 per MWh (in 2014) per capacity valuation in the current IPL Cogeneration & Small Power Production tariff.[35] .

Using the split of on peak and off-peak hours, we created a weighted average avoided cost for biogas. Leveraging the Wood Mackenzie wholesale price forecast, we developed levelized biogas PPA values for each year of the forecast. The resulting PPA values are presented in Table 6-8. For the high-policy support scenario, $21 per metric ton of carbon is added to the value of the PPA. Using the most recent EPA eGRID emissions rates, the $21 per metric ton of carbon adds $20.27 per MWh to the PPA value.[36] We assumed the $21 per metric ton of carbon is instituted in 2017. For PPAs that occur in the high-policy support scenario prior to 2017, the effect of the carbon value is incorporated into the PPA as part of the levelized NPV of the avoided energy costs. However, as the tax would not be implemented until 2017, the portion of the levelized cost representing years 2014-2016 do not include the carbon tax. Only in 2017 and later is the value of carbon applied to all MWhs of energy produced. Table 6-8

[35] http://www.alliantenergy.com/wcm/groups/wcm_internet/@int/@tariff/documents/document/mdaw/mde1/~edisp/015430.pdf.
[36] http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

shows the estimated PPA rates used for each scenario (Base Case and Low Policy Case share the same values)..

The capacity values per MWh were inflated by the Wood Mackenzie capacity price forecast for MISO Zone 3 using the levelized net present value for a 15-year period for each year in the forecast. Capacity prices beyond the Wood Mackenzie forecast were based on the compound annual growth rate exhibited in the forecast for 2025–2035.

Table 6-8. Biogas Summary Table—Estimated PPA ($/MWh)

[TRADE SECRET DATA BEGINS

Year	PPA Base Case	PPA High Policy
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]

TRADE SECRET DATA ENDS]

In comparing the PPA values to the LCOE estimates, we found varying time frames when positive economic returns could occur across the biogas technologies. In the case of landfill gas systems, systems were found to be cost effective in all years of the forecast except for 2014–2016 of the base case and low-policy case. We assume that a five- year development period is required before systems would be operational. As a result, our forecast for each scenario assumes that one 2.0 MW system would added each year starting in 2019, with the full 10 MW potential being reached in 2023.

For WWTP biogas, the reference and low-policy support cases show a positive economic return for only the single 250 kW system. For this system, cost effectiveness is shown to occur in 2015, with the forecast assuming the system would be installed and producing energy in 2017. For the high-policy support case, cost effectiveness is shown for the 250 kW system and two 180 kW systems. For the high-policy support case, these systems are assumed to be added and producing power in 2017.

In the case of farm biogas, the 180 kW dairy system is not shown to be cost effective in the base case or low-policy case. However, the 329 kW and 400 kW swine systems are shown to be cost effective for all years in the base case and low-policy support case. We model the adoption to begin in 2016, with one system of each type being added in every other year of the base case and low-policy support case. For farm-based biogas in the high-policy case, all the technology options were found to be cost effective in all years of the forecast. To model adoption, we assumed that systems would not be installed until 2017 in order to capture the benefit of methane offsets, with three of the dairy systems being added one per year in 2017–2019 (75 percent adoption). For swine systems, we assumed one of the 329 kW and one of 400 kW would be added in each year of the forecast from 2017–2029.

Summer Peak MW were calculated assuming the capacity contribution is equal to the capacity factor for each technology. For biogas projects, we assumed a 90 percent capacity factor for all technologies.

6.3 RESULTS

The forecast modeling of biogas generation results in the capacity additions shown in Table 6-9 through Table 6-11.

Landfill gas forecasts are identical in all scenarios, with all five potential 2.0 MW projects estimated to be cost effective in all years of the forecast period except for the first three years of the base case and low-policy case. Anaerobic digester biogas from wastewater treatment plants (WWTP) and farm-based systems show some additional capacity starting in 2016 in both the base case and low-policy scenario. For the high-policy case, more systems are cost effective, but we forecast an additional year's delay before the first system is operational, as investors would seek to ensure that avoided methane emissions would be valued under the carbon tax scenario. This lag delays the start of adoption until 2017, the year the carbon tax is modeled to start.

Table 6-9. Cumulative Additional Landfill Gas Capacity and Production 2014–2029, All Scenarios

Year	Cumulative MW	Cumulative Summer Peak MW	Cumulative Annual MWh
2014	0.0	0.0	0.0
2015	0.0	0.0	0.0
2016	0.0	0.0	0.0
2017	0.0	0.0	0.0
2018	0.0	0.0	0.0
2019	2.0	1.8	15,768
2020	4.0	3.6	31,536
2021	6.0	5.4	47,304
2022	8.0	7.2	63,072
2023	10.0	9.0	78,840
2024	10.0	9.0	78,840
2025	10.0	9.0	78,840
2026	10.0	9.0	78,840
2027	10.0	9.0	78,840
2028	10.0	9.0	78,840
2029	10.0	9.0	78,840

Table 6-10. Cumulative Additional Biogas Capacity and Production, Wastewater Treatment Plants and Farm-Based Anaerobic Digesters, 2014–2029, Base Case and Low Policy Scenario

Year	Cumulative WWTP MW	Cumulative Farm AD MW	Cumulative Summer Peak MW (WWTP and Farm)	Cumulative Annual MWh (WWTP and Farm)
2014	0.000	0.0	0.0	0.0
2015	0.000	0.0	0.0	0.0
2016	0.000	0.7	0.7	5,747
2017	0.250	0.7	0.9	7,718
2018	0.250	1.5	1.5	13,466
2019	0.250	1.5	1.5	13,466
2020	0.250	2.2	2.2	19,213
2021	0.250	2.2	2.2	19,213
2022	0.250	2.9	2.8	24,961
2023	0.250	2.9	2.8	24,961
2024	0.250	3.6	3.5	30,708
2025	0.250	3.6	3.5	30,708
2026	0.250	4.4	4.2	36,456
2027	0.250	4.4	4.2	36,456
2028	0.250	5.1	4.8	42,203
2029	0.250	5.1	4.8	42,203

Table 6-11. Cumulative Additional Biogas Capacity and Production, Wastewater Treatment Plants and Farm-Based Anaerobic Digesters, 2014–2029, High-Policy Scenario

Year	Cumulative WWTP MW	Cumulative Farm AD MW	Cumulative Summer Peak MW (WWTP and Farm)	Cumulative Annual MWh (WWTP and Farm)
2014	0.0	0.0	0.0	0.0
2015	0.0	0.0	0.0	0.0
2016	0.0	0.0	0.0	0.0
2017	0.610	0.0	0.5	4,809
2018	0.610	0.9	1.4	11,976
2019	0.610	1.8	2.2	19,142
2020	0.610	2.7	3.0	26,309
2021	0.610	3.5	3.7	32,056
2022	0.610	4.2	4.3	37,804
2023	0.610	4.9	5.0	43,551
2024	0.610	5.6	5.6	49,299
2025	0.610	6.4	6.3	55,046
2026	0.610	7.1	6.9	60,794
2027	0.610	7.8	7.6	66,541
2028	0.610	8.6	8.3	72,288
2029	0.610	9.3	8.9	78,036

7. COMBINED HEAT AND POWER

7.1 TECHNOLOGY OVERVIEW

Combined Heat and Power (CHP) is a form of distributed generation (DG) that involves the placement of electric power generating units at or near customer facilities to supply onsite heat and electricity. CHP provides benefits to owners by simultaneously producing useful thermal and power output, with total system efficiencies leading to better economics than buying heat and power as individual energy sources. Specifically, CHP enables the capture of waste heat from the electricity generator, which is typically unusable from central power stations. CHP systems have the potential for a wide range of applications, with higher efficiencies resulting in lower emissions than separate heat and power generation. The advantages of CHP broadly include the following:

- CHP units can be strategically located at the point of energy use.
- Onsite generation avoids the transmission and distribution losses associated with electricity purchased via the grid from central power stations.
- CHP is versatile and can be coupled with existing and planned technologies for many different applications in the industrial, commercial, and residential sectors.

CHP systems consist of a number of individual components—prime mover (heat engine), generator, heat recovery, and electrical interconnection—configured into an integrated whole. The type of equipment that drives the overall system (the prime mover) is typically used to identify the type of CHP system being used. Prime movers for CHP systems include reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells. These prime movers are capable of utilizing a variety of fuels, including natural gas, coal, oil, and alternative fuels to produce mechanical energy. Although mechanical energy from the prime mover is most often used to drive a generator to produce electricity, it can also be used to directly drive rotating equipment such as compressors, pumps, and fans. Thermal energy from the system can be used in direct process applications or indirectly to produce steam, hot water, hot air for drying, or chilled water for process cooling.

Figure 7-1 shows the efficiency advantage of CHP compared with conventional central station power generation and onsite boilers. When considering both thermal and electrical processes together, CHP has the potential to require only three-quarters of the primary fuel energy required by separate heat and power systems.

Figure 7-1. CHP vs. Separate Heat and Power Production[37]

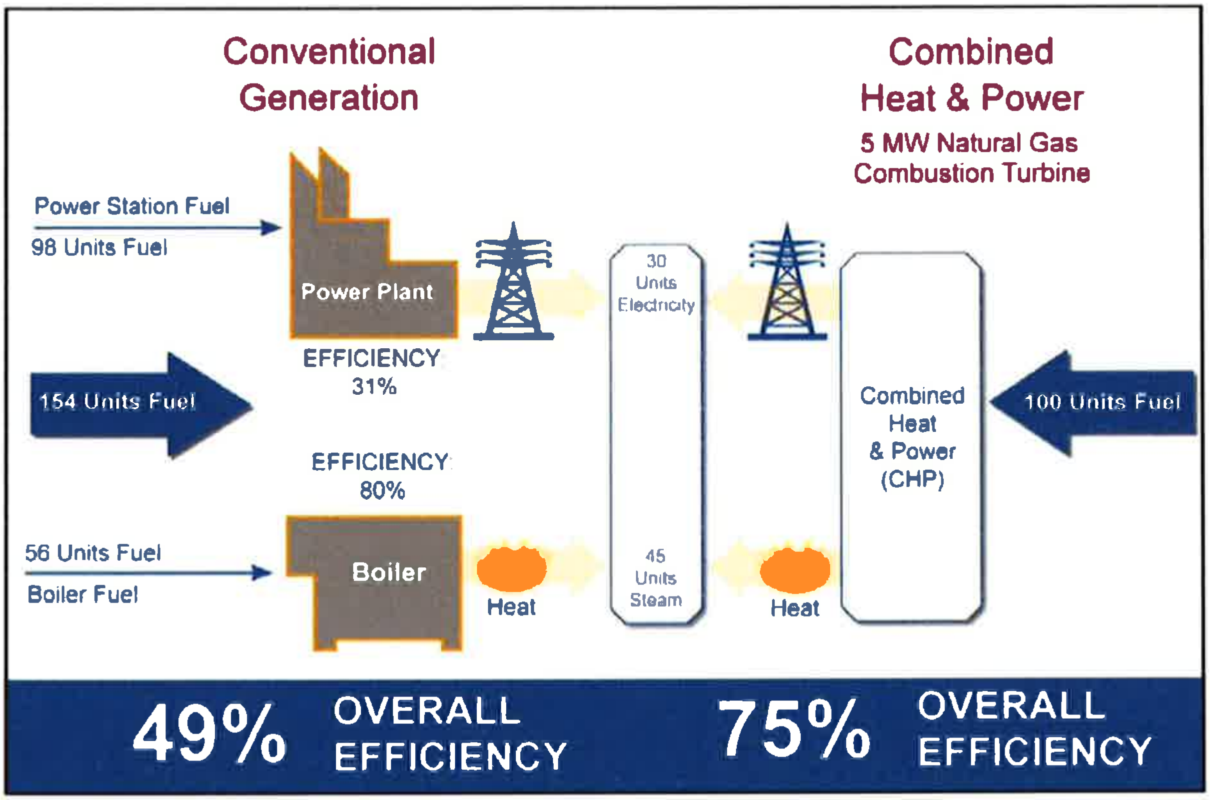


Table 7-1 and Table 7-2 provide a summary of the key cost and performance characteristics of CHP technologies.

[37] US EPA Combined Heat and Power Partnership, Catalog of CHP Technologies, December 2008.

Table 7-1. Summary of CHP Technologies[38]

CHP system	Advantages	Disadvantages	Available sizes
Gas turbine	High reliability. Low emissions. High-grade heat available. No cooling required.	Require high pressure gas or in-house gas compressor. Poor efficiency at low loading. Output falls as ambient temperature rises.	500 kW to 250 MW
Microturbine	Small number of moving parts. Compact size and light weight. Low emissions. No cooling required.	High costs. Relatively low mechanical efficiency. Limited to lower temperature cogeneration applications.	30 kW to 250 kW
Spark ignition (SI) reciprocating engine	High power efficiency with part-load operational flexibility. Fast start-up. Relatively low investment cost. Can be used in island mode and have good load following capability. Can be overhauled on site with normal operators. Operate on low-pressure gas.	High maintenance costs. Limited to lower temperature cogeneration applications. Relatively high air emissions. Must be cooled even if recovered heat is not used. High levels of low frequency noise.	< 5 MW in DG applications
Compression ignition (CI) reciprocating engine (dual fuel pilot ignition)	High speed (1,200 RPM) ≤4MW Low speed (102-514 RPM) 4–75 MW		High speed (1,200 RPM) ≤4MW Low speed (102–514 RPM) 4–75 MW
Fuel Cells	Low emissions and low noise. High efficiency over load range. Modular design.	High costs. Low durability and power density. Fuels requiring processing unless pure hydrogen is used.	5 kW to 2 MW

[38] Ibid.

Table 7-2. Summary Table of Typical Cost and Performance Characteristics by CHP Technology*[39]

Technology	Internal Combustion Engine	Gas Turbine	Microturbine	Fuel Cell
Power efficiency (HHV)	22–40%	22–36%	18–27%	30–63%
Overall efficiency (HHV)	70–80%	70–75%	65–75%	55–80%
Effective electrical efficiency	70–80%	50–70%	50–70%	55–80%
Typical capacity (MWe)	0.01–5	0.5–250	0.03–0.25	0.005–2
Typical power to heat ratio	0.5–1	0.5–2	0.4–0.7	1–2
Part-load	ok	poor	ok	good
CHP Installed costs ($/kWe)	1,100–2,200	970–1,300 (5–40 MW)	2,400–3,000	5,000–6,500
O&M costs ($/kWhe)	0.009–0.022	0.004-0.011	0.012–0.025	0.032–0.038
Availability	92–97%	90–98%	90–98%	>95%
Hours to overhauls	25,000-50,000	25,000-50,000	20,000–40,000	32,000–64,000
Start-up time	10 sec	10 min–1 hr	60 sec	3 hrs–2 days
Fuel pressure (psig)	1–45	100-500 (compressor)	50–80 (compressor)	0.5–45
Fuels	natural gas, biogas, propane, landfill gas	natural gas, biogas, propane, oil	natural gas, biogas, propane, oil	hydrogen, natural gas, propane, methanol
Noise	high	moderate	moderate	low
Uses for thermal output	hot water, LP steam	heat, hot water, LP-HP steam	heat, hot water, LP steam	hot water, LP-HP steam
Power Density (kW/m2)	35–50	20-500	5–70	5-20
NOx (lb/MMBtu) (not including SCR)	0.013 rich burn 3-way cat. 0.17 lean burn	0.036–0.05	0.015–0.036	0.0025-.0040
lb/MWhTotalOutput (not including SCR)	0.06 rich burn 3-way cat. 0.8 lean burn	0.17–0.25	0.08–0.20	0.011-0.016

[39] Ibid.

Within Iowa and Minnesota, the US Department of Energy[40] indicates a total of 1,548 MW of CHP capacity has been installed. Most of this capacity is for very large industrial steam systems found in chemical processing, food processing, pulp and paper industries, and other large manufacturing plants. Fuel sources include coal, biomass, and waste materials. These large CHP plants are designed to serve specific industrial facilities and in the USDOE data are frequently identified as over 10 MW (over 100 MW in some cases). In many respects, these larger CHP systems are more akin to central power stations than traditional distributed generation due to their capacity and customer specific designs. The vast majority of these systems were installed prior to the year 2000, with some operating since the 1940s.

IPL identified three distributed generation CHP systems currently operating in its service territory. These include two using wood waste to fire steam turbines. One unit operates at 55 kW (started in 2005), and the other at 450 kW (started in 1997). In 2009 a 2.8 MW system using natural gas fired engines was brought on line. Thus, the market adoption of smaller distributed generation CHP has been limited. That said, CHP outside the distributed generation context does operate in the IPL territory, with a 12 MW plant indicated as operating at a large industrial manufacturer. We also speculate that with the large presence of food processors and ethanol plants in Iowa and Minnesota, IPL does serve load that could be served with distributed generation CHP (DG CHP) systems.

For the purposes of this forecast, we assume that 10 MW is the upper threshold to be considered distributed generation and with potential for a generalizing to a market. Systems over 10 MW require very large thermal and electricity loads, requiring a review of specific customers and financial decision making, more akin to a feasibility study than a general market forecast.

Although Iowa and Minnesota have shown little in the way of recent DG CHP installations, there are other locations in the US where DG CHP has been active over the past decade. California has shown substantial activity, where polices to incentivize DG CHP were enacted in 2001 that led to significant growth. Over the last decade, over 220 MW of DG CHP system capacity was installed in California, utilizing the Self-Generation Incentive Program (SGIP).[41] The primary technologies installed, in order of installed capacity, were internal combustion engines, gas turbines, microturbines and fuel cells.

Other state and federal DG CHP programs were established in the early 2000s. The most prevalent program is the Combined Heat and Power Partnership initiated by EPA. This organization counts over 500 members and is a comprehensive resource of DG CHP information.

In the DG CHP sector, these projects are developed based on investment criteria driven by the value of electricity and value of thermal energy. An owner evaluates the savings on electricity and fuel for a heat source when making this investment decision. The value proposition is monetized in part via net metering, avoided energy purchases, and/or PPA values.

---

[40] http://www.eea-inc.com/chpdata/.

[41] Itron, Inc. CPUC Self-Generation Incentive Program Tenth-Year Impact Evaluation Final Report; Submitted to: PG&E and The Self-Generation Incentive Program Working Group, July 7, 2011, Davis, CA.

For purposes of forecasting additional DG CHP installations in the IPL service territory, our analysis used a typical range of DG CHP systems and sizes currently in service in the US. These included:

1) Fuel cells at 300 kW and 1,400 kW
2) Combustion turbines at 2,900 kW and 5,280 kW
3) Internal combustion engines at 500 kW and 1,500 kW
4) Microturbines at 200 kW.

There are no new state or local incentive programs to support DG CHP. At the federal level, an ITC remains in effect until the end of 2016, offering a tax credit of 30 percent of installed cost for fuel cells and 10 percent for other DG CHP technologies.

7.2 METHODOLOGY

The methodology used to forecast DG CHP relies on several key assumptions:

1) These systems will be installed as an investment decision to supply power to the grid with the electricity value modeled as equivalent to a long-term power purchase agreement.
2) Standby charges for electricity and electrical service reduce avoided retail offsets to the value of an equivalent PPA.
3) The electrical distribution system does not limit the growth of potential CHP capacity for the growth forecasted.
4) Growth patterns through 2016 will reflect the presence of the federal ITC for select technologies.
5) Natural gas will be the fuel option,
6) Existing capacity is maintained or replaced at the same level of performance with the forecast reflecting incremental additions of DG CHP to energy capacity.

To model DG CHP we analyzed the technical potential in the four technology categories and sized generating capacity based on available DG CHP commonly used in North America. Modeling was undertaken reflecting a base case (existing conditions), a low-policy support case and a high-policy support case. The high-policy support situation was modeled to reflect a carbon tax valued at $21 per metric ton of CO_2 removed. The base and low-policy scenarios anticipate the PTC and ITC are not renewed.

7.2.1 Economic modeling

In all DG CHP categories, we assume that financial returns drive investment decisions. To forecast future additions of DG CHP capacity, we developed an economic model to understand when, if, and in what policy context DG CHP may become cost effective in the forecast period.

In all categories, the basic economic model considers the levelized cost of energy (LCOE) compared to the assumed levelized value of a DG CHP power. The levelized value of electricity was modeled using an estimated power purchase agreement (PPA) to create a proxy for the value of electricity and capacity net of standby charges. For each year of the forecast period an LCOE for DG CHP and a PPA value were developed, allowing for judgment of whether DG CHP may be attractive to develop. In years where the estimated PPA would exceed the LCOE, we assume investments may occur. Table 7-3 describes the assumptions of the LCOE analysis.

We used various data sources and assumptions to establish the LCOE for DG CHP. The primary sources of this information include the US EPA Catalog of CHP Technologies, regularly updated by the EPA CHP Partnership, and the California Public Utilities Commission... These data sources establish typical size ranges in commercial operation across the US for each technology types. Accordingly, we selected technology sizes (nameplate capacity) near the typical upper and lower boundaries, supported by enough installations and commercial operating experience to establish credible values for capital and operating costs. We further checked against manufacturer product lines to be certain the target size units were available. These are blended to achieve national averages, which we used in this study. The LCOE is modeled assuming a 15-year PPA span. This duration is somewhat less than the 20-year useful life for gas turbines and internal combustion engines. In these cases, the five year difference in PPA and useful life is expressed as a salvage value of 25 percent (5 years of 20 remaining), incorporated into the model with a net present value based on the remaining years' useful life.

Table 7-3. DG CHP LCOE Assumptions

DG CHP LCOE Factor	LCOE Metric						
	Fuel Cell		Gas Turbine		Internal Combustion Engine		Micro Turbine
System kW	300	1,400	2,900	5,280	500	1,500	200
Overnight Capital Cost ($/kW)	6,990	6,090	3,091	2,332	1,791	1,388	3,600
Annual system MWh	1,865	8,707	20,577	37,464	1,752	5,256	788
O&M Cost ($/kW-yr)	186.59	186.59	134.82	134.82	43.45	25.58	78.84
Salvage value (%)	0	0	25	25	25	25	0
Marginal Tax Rate	35%	Assumed corporate tax rate					
MACRS NPV factor	0.288	Net present value factor of 5 year MACRS depreciation					
Discount rate	7.44%	Utility weighted average cost of capital, per IPL					
Inflation rate	2.0%	Assumed general inflation rate, 2014-2029					

Performance factors for DG CHP are based on research conducted in California. The CPUC Self-Generation Incentive Program Cost-Effectiveness of Distributed Generation Technologies Final Report[42] shows that theoretical efficiencies for DG CHP have not been achieved in practice though may still show a net benefit from component heat and power energy sources. Our performance estimates for DG CHP in the IPL service territory is based on this experience and illustrated in Table 7-4.

[42] Itron, Inc. CPUC Self-Generation Incentive Program-Cost-Effectiveness of Distributed Generation Technologies Final Report; Submitted to: PG&E, February 9, 2011, Davis, CA.

Table 7-4. Performance Factors for CHP Technology

	Fuel Cell		Gas Turbine		ICE		Microturbine
Nameplate Capacity (kW)	300	1,400	2,900	5,280	500	1,500	200
Annual Performance Degradation (%)	5%	5%	0%	0%	6%	6%	5%
Electrical Conversion Efficiency (%), LHV)	40%	40%	33%	33%	31%	31%	33%
Thermal Conversion Efficiency (%), LHV)	12%	12%	17%	17%	32%	32%	17%
Heat Recovered Rate (mBtu/kWh generated)	0.78	0.78	3.06	3.06	3.07	3.07	2.21
Fuel Utilization or Input (mmBtu/H)	3.90	17.90	42.60	62.4	4.57	12.85	2.06
Recovered heat (MMBtu/yr)	1,455	6,792	62,966	114,642	5,379	16,136	1,742
Boiler energy @ 80 percent efficiency	1,819	8,490	78,708	143,303	6,723	20,170	2,178
NG CHP consumption (MMBtu per year)	24,256	111,331	302,273	442,765	16,013	45,026	8,121

The base case and low-policy scenarios result in the same outcomes, with the high policy case showing better financial performance for the calculated levelized cost of energy based on the $21 per ton of carbon assumption. Table 7-5 presents the LCOE for each year in the forecast period.

Table 7-5. Summary Table LCOE for DG CHP ($/MWh)

Year	Fuel Cell		Gas Turbine		ICE		Micro Turbine
System kW	300	1,400	2,900	5,280	500	1,500	200
2014	$245.98	$182.35	$127.96	$99.75	$106.07	$104.65	$89.16
2015	$253.07	$187.68	$132.04	$102.86	$109.17	$107.61	$91.63
2016	$261.11	$193.74	$136.78	$106.46	$112.70	$110.96	$94.42
2017	$269.02	$199.70	$141.41	$109.98	$116.16	$114.26	$97.17
2018	$276.74	$205.50	$145.88	$113.39	$119.54	$117.49	$99.86
2019	$283.89	$210.86	$149.94	$116.50	$122.66	$120.49	$102.38
2020	$290.45	$215.76	$153.55	$119.28	$125.51	$123.25	$104.71
2021	$296.96	$220.62	$157.12	$122.03	$128.34	$126.00	$107.03
2022	$304.19	$226.04	$161.17	$125.14	$131.49	$129.04	$109.58
2023	$311.29	$231.34	$165.10	$128.17	$134.57	$132.03	$112.10
2024	$318.56	$236.78	$169.14	$131.27	$137.74	$135.09	$114.68
2025	$325.98	$242.33	$173.26	$134.44	$140.97	$138.21	$117.31
2026	$333.54	$247.98	$177.46	$137.67	$144.25	$141.40	$119.99
2027	$341.12	$253.64	$181.65	$140.89	$147.55	$144.59	$122.68
2028	$349.11	$259.62	$186.10	$144.32	$151.03	$147.95	$125.50
2029	$357.57	$265.96	$190.87	$147.97	$154.71	$151.51	$128.49

To estimate the estimated PPA value against which the LCOE is compared, we developed a PPA forecast using wholesale price forecasts for MISO on peak and off-peak values developed for Alliant Energy by Wood Mackenzie. Additionally, a capacity credit value is added to the PPA at $11.90 per MWh (in 2014) based on current IPL tariffs.[43] The capacity values per MWh were inflated by the Wood Mackenzie capacity price forecast for MISO Zone 3 using the levelized net present value for a 15-year period for each year in the forecast. Capacity prices beyond the Wood Mackenzie forecast were based on the compound annual growth rate exhibited in the forecast for 2025–2035.

Using the split of MISO on peak and off-peak hours, reflecting the Wood Mackenzie presentation of MISO level data, we created a weighted average avoided cost value of electricity for DG CHP. Using the Wood Mackenzie wholesale price forecast, we estimated levelized DG CHP PPA values for each year of the DG forecast. The resulting estimated PPA values are presented in Table 7-6. For the high policy support scenario, a $21 per metric ton of carbon is added to the value of the PPA. Using the most recent EPA eGRID emissions rates,[44] the $21 per metric ton of carbon adds $20.27 per MWh to the PPA value. We assume

[43] http://www.alliantenergy.com/wcm/groups/wcm_internet/@int/@tariff/documents/document/mdaw/mde1/~edisp/015430.pdf
[44] http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html.

the $21 per metric ton of carbon is instituted in 2017. For PPAs that occur in the high policy support scenario prior to 2017, the effect of the carbon value is incorporated into the estimated PPA as part of the levelized NPV of the avoided energy costs, which do not include the value of carbon for the years 2014–2016. Only in 2017 and later is the value of carbon applied to all MWhs of energy produced. Table 7-6 shows the effect of the carbon value on PPA rates for the high policy support scenario.

Table 7-6. CHP Summary Table–Estimated PPA ($/MWh)

[TRADE SECRET DATA BEGINS

Year	Estimated PPA Base Case	Estimated PPA High Policy
2014	[redacted]	[redacted]
2015	[redacted]	[redacted]
2016	[redacted]	[redacted]
2017	[redacted]	[redacted]
2018	[redacted]	[redacted]
2019	[redacted]	[redacted]
2020	[redacted]	[redacted]
2021	[redacted]	[redacted]
2022	[redacted]	[redacted]
2023	[redacted]	[redacted]
2024	[redacted]	[redacted]
2025	[redacted]	[redacted]
2026	[redacted]	[redacted]
2027	[redacted]	[redacted]
2028	[redacted]	[redacted]
2029	[redacted]	[redacted]

TRADE SECRET DATA ENDS]

In addition to providing electricity, CHP systems consume natural gas as the fuel source, reducing the need for fuel consumed in a boiler. The consumption of natural gas creates an additional expense for the system and offsets the value of avoided electricity expenses. Additionally, the combustion of natural gas creates a carbon emission source from which the $21 per ton tax would create an expense. Levelized natural gas prices were forecasted using the current lowest variable costs of natural gas for non-transport IPL natural gas customers in the 2013 rate sheets ($6.13 per Dth). These costs were adjusted by the Wood Mackenzie wholesale natural gas cost price changes for each year in their forecast. For time periods beyond the Wood Mackenzie forecast, the inflation rate is estimated by using the compound annual growth rate of the Wood Mackenzie forecast from 2025–2035. Table 7-7 shows the net natural gas expense estimates for 15 years of natural gas consumption, per annual Dth, for the forecast period. The data represent the net present value of the natural gas expense commitment a DG CHP purchaser would be making for each annual Dth of consumption for a 15-year period.

Table 7-7. Levelized Expense of Net Natural Gas

[TRADE SECRET DATA BEGINS

Year	15-Year NPV per Annual Dth
2014	[redacted]
2015	[redacted]
2016	[redacted]
2017	[redacted]
2018	[redacted]
2019	[redacted]
2020	[redacted]
2021	[redacted]
2022	[redacted]
2023	[redacted]
2024	[redacted]
2025	[redacted]
2026	[redacted]
2027	[redacted]
2028	[redacted]
2029	[redacted]

TRADE SECRET DATA ENDS]

For all the technologies, increased natural gas expenses create a substantial burden for the project economics. On a levelized per MWh basis, these costs reduce the estimated PPA value by no less than 50 percent for the most efficient technology (200 kW microturbine). In the high- policy case, there is some incremental benefit to the carbon tax, but insufficiently so to drive project economics into a positive territory.

7.3 RESULTS

In comparing the PPA values to the LCOE estimates, we find no period when positive economic returns occur. This is a pass-fail test, with CHP failing in all instances. If cost factors decline or achieved efficiencies increase, it is possible that CHP could become cost effective in the IPL service territory during the forecast period. The most cost effective DG CHP technology we reviewed is a 200 kW microturbine. After accounting for natural gas costs, the shortfall in cost effectiveness in the base case and low- policy case ranges from $19.65 per MWh in 2014 to $29.27 per MWh in 2029. In the high- policy case, the effect of the carbon tax reduces the shortfall to $5.34 per MWh in 2014 and $9.00 per MWh in 2029.

RESOURCE ALTERNATIVES

This section of the IRP reviews the supply-side and demand-side resources reviewed in the resource plan. Black & Veatch developed a 2013 Power Station Characterization Study (B&V Study) for IPL which is the main source of information for supply-side resources, and covers a wide range of alternatives. A copy of the Table of Contents from the 2013 Power Station Characterization Study is included in Appendix 5A.

5.0 Supply-Side Alternatives

Many technologies are applicable to supply-side resources. These technologies are separately discussed in subsequent sections. For purposes of this B&V Study, supply-side technologies are categorized as follows:

Category	Technology
Renewable	Wind
	Solar-Photovoltaic
	Solar-Thermal
	Biomass
	Geothermal
	Biogas-Anaerobic Digestion
	Biogas-Landfill Gas
	Hydro
Fossil Fuel	Pulverized Coal
	Combined Cycle
	Combustion Turbine
	Integrated Gasification Combined Cycle
Purchased Power	Cogeneration/Distributed Generation
	Independent Power Producer
	Another Utility
	MISO Market Energy
Nuclear	Nuclear

5.0.1 Renewable

Renewable resources refer to resources that constantly renew themselves or that are regarded as practically inexhaustible. In addition, renewable resources have positive environmental benefits. The eight renewable technologies discussed in this IRP are wind, solar-photovoltaic, solar-thermal, biomass, geothermal, biogas-anaerobic digestion, biogas-landfill gas and hydro.

5.0.1a Wind

Wind power is a viable option for IPL. Currently, IPL has contracted for approximately 250 MW (nameplate) of wind energy, of which almost all is located in Iowa. Additionally, IPL has installed 200 MW of owned-wind generation in Iowa (Whispering Willow Windfarm – East or WWE). WWE was put in-service late 2009. Summary historical actual wind data for IPL's wind resources is included in Appendix 5B. For EGEAS modeling, IPL approximates an average capacity factor based on the actual data from a historical year. Section 8 of the B&V Study focuses on renewable energy technology options.

5.0.1b Solar-Photovoltaic (PV)

With recent declines in capital costs, PV has achieved more consumer recognition over the last few years. The overnight cost of commercial PV capacity, as developed in the B&V Study, was estimated to be between $2,800 per kW and $3,300 per kW for a facility of 10 MW with an approximate capacity factor of 20-20.5 percent. Solar PV was modeled as a resource option in the EGEAS analysis for this IRP.

5.0.1c Solar-Thermal

A general feature of solar thermal systems and solar technologies is that peak output typically occurs on summer days when electrical demand, while not necessarily at its daily peak, is high. However, the costs of this technology are still greater than $5,750 per kW. There is poor potential for utilization of solar thermal energy within IPL's service territory. Coupling the high technology costs with poor potential for utilization makes this technology an unattractive option for IPL at this time.

5.0.1d Biomass

There is reasonable potential for power production from biomass combustion in IPL's service territory. Fuel stream limitations and higher capital costs make this option less attractive; however, biomass was modeled as an option in the EGEAS analysis for this resource plan.

5.0.1e Geothermal

Geothermal power is limited to locations where geothermal pressure reserves are found. Well temperature profiles determine the potential for geothermal development and the type of geothermal power plant installed. Because there are no known significant geothermal sources in this region, the potential for electricity generation from geothermal energy is poor in IPL's service territory.

5.0.1f Biogas-Anaerobic Digestion

The most common applications of anaerobic digestion use industrial wastewater, animal manure or human sewage. In agriculture applications, anaerobic digesters can be installed where there is a clean, continuous source of manure. For on-farm manure digestion, the resource is readily accessible and only minor modifications are required to the existing manure management techniques. In some cases, economies of scale may be realized by transporting manure from multiple farms to a central digestion facility. IPL's service territory covers vast areas of farm land with large numbers of livestock; therefore, there is good potential for anaerobic digestion within IPL's service territory.

5.0.1g Biogas-Landfill Gas

From an energy generation perspective, Landfill gas (LFG) is a valuable resource that can be burned as fuel by reciprocating engines, small combustion turbine generators or other devices. Gas production in a landfill is primarily dependent upon the depth of waste in place, age of waste in place and amount of precipitation received by the landfill. There is good potential for power generation from LFG in IPL's service territory. Currently, landfill gas utilization generates over 115 MW of electricity at landfills in Minnesota and Iowa.

5.0.1h Hydro

Hydroelectric generation is usually regarded as a mature technology that is unlikely to advance. The best sources of hydro generation in IPL's service territory have already been developed. Therefore, additional hydroelectric generation in IPL's service territory is most likely limited to upgrading of existing facilities. Currently, hydroelectric power is a very small percentage of IPL's resource mix.

5.0.2 Fossil Fuel

Most of the electrical energy generated by IPL's generating facilities is with fossil fuels such as coal and natural gas.

5.0.2a Pulverized Coal

Due to comparatively low fuel costs and mature technology, much of the energy generated on IPL's utility system is from units fueled by pulverized coal.

5.0.2b Combined Cycle

Combined cycle refers to the recovery of heat from one turbine, as an example from a combustion turbine, to generate steam to run another generator. Input fuels are oil, natural gas or coal gas. Such units are more efficient than pulverized coal units and can be constructed in stages. Combined cycle units are options to consider for future IPL resources.

5.0.2c Combustion Turbine

IPL has a number of combustion turbines on its system, but these units are peaking units and generate only a small amount of the total electrical energy produced by IPL. Combustion turbine units continue to be attractive options for meeting system requirements at peak times.

5.0.2d Integrated Gasification Combined Cycle

The integrated gasification combined cycle (IGCC) application for power generation is relatively new and uses the Shell Coal Gasification Process. The potential environmental advantages of this technology may be offset by a higher capital investment and lower initial plant availability. An IGCC plant takes almost five years to reach full capability. The current uncertainties surrounding IGCC make this technology not as desirable of an option as others today; however, with technological advances and improvements, IGCC may be an option more suitable for future consideration.

5.0.3 Purchased Power

IPL purchases electrical energy from the MISO, other utilities, independent developers and power marketers. The decisions regarding purchased power are primarily functions of need, availability and cost. IPL will continue to purchase power when it makes sense to do so.

5.0.3a Cogeneration/Distributed Generation

Cogeneration refers to facilities that produce electricity as well as other forms of energy. Section 4 of this resource plan details the distributed generation potential.

5.0.3b Independent Power Producer

An independent power producer (IPP) is a non-utility that produces electrical energy for use by electric utilities. IPPs use the same technologies as electric utilities. Capacity and energy from IPPs will continue to be evaluated and used, if available and economical.

5.0.3c Another Utility

IPL routinely purchases power from other utilities on a short-term or seasonal basis. Since the firm load of IPL is growing, additional capacity and energy will be needed in the future. Therefore, if available and economical, purchased power from another utility could be used.

5.0.3d MISO Market Energy

IPL purchases power many hours throughout the year from MISO. In IPL's IRP modeling, energy from the market can be purchased in every hour of every year of the study period when available and economic.

5.0.4 Nuclear

Typical nuclear units are rated at 600 MW or larger and have high capital requirements. Nuclear was modeled as a resource alternative in the EGEAS analysis for this resource plan.

5.1 Demand-Side Alternatives

DSM programs for this resource plan are categorized into two types of programs: conservation (non-dispatchable) and load management (dispatchable). IPL has achieved considerable demand and energy savings from DSM programs. DSM programs will continue to be a potential resource alternative provided such programs are economical. DSM is discussed further in Section 3 of this resource plan.

5.2 Future Resource Alternatives

Based on the screening of all resource alternatives and the conclusions given in Sections 5.0 and 5.1, Purchased Power, Combustion Turbines, Combined Cycles, Pulverized Coal, IGCC, Wind, Biomass, Biogas, Solar and Nuclear were all evaluated in some form for this resource plan. IPL is committed to meeting the demands of its customers with economic, reliable, safe and environmentally sound resources. Furthermore, IPL's DSM programs and renewable resource portfolio demonstrate IPL's commitment to environmentally sound resources as part of its resource mix.

Information as to the types, sizes and costs for all future units modeled in EGEAS for this resource plan is given in Appendix 5C. With respect to resource costs changing over time, nominal change rates for O&M expenses and capital investment can be found in Appendix 5D.

FINAL

2013 POWER STATION CHARACTERIZATION STUDY

B&V PROJECT NO. 179934
B&V FILE NO. 40.1200

REVISION 2

PREPARED FOR

Alliant Energy

NOVEMBER 2013

BLACK & VEATCH
Building a world of difference.

Table of Contents

LIST OF TABLES

LIST OF FIGURES

IPL's Existing Purchased Wind Sources

GWH output:

EGEAS Name	MW	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	average
WIND IPW CERRO	41.3	101	100	106	101	101	91	103	105	95	84	75	82	87	95
WIND IPW FLYING	43.5					156	151	152	144	141	125	134	142	149	144
WIND IPW BINGHAM	15								43	42	40	41	43	44	42
WIND IPW ADAMS	6					14	13	15	15	14	13	13	13	13	14
WIND IES BEAVER	3.9					11	10	11	11	10	9	9	10	10	10
WIND IES BUENA	78.75	214	206	229	192	180	193	205	185	162	147	167	189	196	190
WIND IES HANCOCK	56.8					156	138	153	148	139	130	139	140	149	144
WIND HARDIN HILL	14.7									29	39	39	47	47	40
WIND JCT HILLTOP	8													23	23
WHISP WIL E WIND	200											353	568	579	500

CF % output:

EGEAS Name	MW	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	average
WIND IPW CERRO	41.3	28%	28%	29%	28%	28%	25%	28%	29%	26%	23%	21%	23%	24%	26%
WIND IPW FLYING	43.5					41%	40%	40%	38%	37%	33%	35%	37%	39%	38%
WIND IPW BINGHAM	15								33%	32%	30%	31%	33%	34%	32%
WIND IPW ADAMS	6					26%	25%	28%	29%	27%	24%	25%	25%	26%	26%
WIND IES BEAVER	3.9					32%	31%	31%	33%	30%	28%	27%	29%	29%	30%
WIND IES BUENA	78.75	31%	30%	33%	28%	26%	28%	30%	27%	24%	21%	24%	27%	28%	28%
WIND IES HANCOCK	56.8					31%	28%	30%	30%	28%	26%	28%	28%	30%	29%
WIND HARDIN HILL	14.7									23%	30%	31%	37%	37%	31%
WIND JCT HILLTOP	8													33%	33%
WHISP WIL E WIND	200											20%	32%	33%	29%

CERRO = Hawkeye Power Partners
BINGHAM = Windom Wind Farm
ADAMS = G McNeilus, NcNeilus Windfarm LLC, and GARMAR Wind
BEAVER = Minn Wind I & II
BUENA = Storm Lake Power Partners

Developed from Black & Veatch 2013 Power Station Characterization Study

Generic Alternative Characteristics
IPL 2014 IRP

EGEAS Unit	Rated Capacity (MW)	Operating Capacity (MW)	Reserve Capacity (MW)	Forced Outage Rate	Full Load Heat Rate (BTU/KWH)	Fuel Price ($/MMBTU)	Fixed O&M Cost ($/KW-Yr)	Technology Variable O&M ($/MWH)	Iowa Generation Tax ($/MWH)	EGEAS Variable O&M ($/MWH)	EPC Costs ($/KW)	Owner's & AFUDC Cost	Capital Cost ($/KW)	Book Life (Years)	Levelized Carrying Charge Rate	ROE
CT-38 (GE LM6000 PH)	37.9	37.9	29.854	21.230%	10,120	$ 3.92	$ 28.80	$ 11.45	$ 0.60	$ 12.05	$ 1,493	30%	$ 1,941	27	11.490%	10.000%
CT-88 (GE LMS100PA)	87.8	87.8	82.590	5.934%	8,990	$ 3.92	$ 12.98	$ 7.01	$ 0.60	$ 7.61	$ 1,145	30%	$ 1,489	27	11.490%	10.000%
CT-93 (Wartsila 6x18V50SG)	92.7	92.7	87.199	5.934%	10,040	$ 3.92	$ 12.73	$ 12.81	$ 0.60	$ 13.41	$ 1,419	30%	$ 1,845	27	11.490%	10.000%
CT-192 (GE 7F 5-Series)	191.7	191.7	180.325	5.934%	10,210	$ 3.92	$ 6.33	$ 17.24	$ 0.60	$ 17.84	$ 669	30%	$ 870	27	11.490%	10.000%
CC-300 (1x1 GE 7F 5-Series)	299.8	299.8	284.474	5.112%	6,700	$ 3.92	$ 8.77	$ 2.99	$ 0.60	$ 3.59	$ 1,025	35%	$ 1,383	27	12.113%	11.000%
CC-605 (2x1 GE 7F 5-Series)	604.7	604.7	573.788	5.112%	6,640	$ 3.92	$ 5.97	$ 2.93	$ 0.60	$ 3.53	$ 820	35%	$ 1,106	27	12.113%	11.000%
CC-300J	300	300	284.664	5.112%	6,640	$ 3.92	$ 5.97	$ 2.93	$ 0.60	$ 3.53	$ 820	35%	$ 1,106	27	12.113%	11.000%
SOLAR10 (PV 20.5% CF)	10	10	4.870	-	-	$ -	$ 32.50	$ -	$ 0.60	$ 0.60	$ 2,750	12%	$ 3,080	25	10.547%	11.000%
BIOMASS35 (Directed Fired)	35	35	32.900	6.000%	13,250	$ 3.50	$ 145.00	$ 10.50	$ 0.60	$ 11.10	$ 5,200	25%	$ 6,500	35	11.317%	11.000%
BIOGAS10 (Landfill Gas)	10	10	9.400	6.000%	12,500	$ 1.50	$ 70.00	$ 17.50	$ -	$ 17.50	$ 2,500	20%	$ 3,000	35	11.317%	11.000%
WIND 100 (41% CF)	100	100	14.1	-	-	$ -	$ 36.00	$ -	$ -	$ -	$ 1,750	15%	$ 2,013	25	10.547%	11.000%
PC600 (USCPC)	600	600	555.642	7.393%	9,290	$ 2.38	$ 23.83	$ 3.44	$ 0.60	$ 4.04	$ 2,542	45%	$ 3,685	35	11.317%	11.000%
PC420wCC (USCPC w/CC)	420	420	388.949	7.393%	13,453	$ 2.38	$ 45.50	$ 6.58	$ 0.60	$ 7.18	$ 6,495	45%	$ 9,418	35	11.317%	11.000%
IGCC568	568	568	526.008	7.393%	8,800	$ 2.38	$ 35.24	$ 6.42	$ 0.60	$ 7.02	$ 3,748	55%	$ 5,810	35	11.317%	11.000%
PPCT 1YR 50 (capacity only)	50	0	50	-	-	-	~$1 initially	-	-	-	-	-	-	1	-	-
PPCT 10YR 150	150	150	141.099	5.934%	10,210	ref to CT-192	$ 116.25	$ 17.24	$ 0.60	$ 17.84	-	-	-	10	-	-
PPCC 10YR 150	150	150	142.332	5.112%	6,640	ref to CC-605	$ 153.39	$ 2.93	$ 0.60	$ 3.53	-	-	-	10	-	-
PPPC 10YR 150	150	150	138.911	7.393%	9,290	ref to PC600	$ 482.62	$ 3.44	$ 0.60	$ 4.04	-	-	-	10	-	-
NUCLEAR 300J	300	300	291.150	2.950%	10,400	$ 0.74	$ 140.54	$ -	$ 0.60	$ 0.60	$ 4,168	45%	$ 6,044	35	11.317%	11.000%

Costs are 2013$

In EGEAS, 10 year PTC impact is modeled using Detailed Capital Costs for Biomass, Biogas, and Wind:

Biomass (open loop) $11/MWH x 35 MW x 85% CF x 8760 h / 35,000 KW / (1 - 41.57% tax gross-up) = -140 $/kW-y over 10 year book life and 100% LFCR
Biogas $11/MWH x 10 MW x 87.5% CF x 8760 h / 10,000 KW / (1 - 41.57% tax gross-up) = -144 $/kW-y over 10 year book life and 100% LFCR
Wind $23/MWH x 100 MW x 41% CF x 8760 h / 100,000 KW / (1 - 41.57% tax gross-up) = -141 $/kW-y over 10 year book life and 100% LFCR

In EGEAS, Solar 25 year ITC impact is modeled using Detailed Capital Costs:

30% of capital investment spread over 25 years, 30% x $3,080/kw / (1 - 41.57% tax gross-up) / 25 yrs = -63 $/kw-y over 25 year book life and 100% LFCR
Drops from 30% to 10% for investments after 2016.

- New wind costs equivalent to $45/MWH levelized over 25 year life for a 2013 addition.
- Total new and existing wind limited to 25% of energy

IPL 2014 IRP Escalation Rates (nominal)

Developed from data provided by Energy Information Administration Staff as used in 2013 Annual Energy Outlook

Online Year	Comb. Turb	Comb. Cyc	Solar PV	Biomass	Landfill Gas	Wind	Pulv. Coal	Coal w/seq	IGCC	Nuclear
2013	3.8%	3.8%	-4.5%	-1.4%	3.8%	3.7%	3.7%	3.6%	3.7%	3.6%
2014	5.5%	5.5%	1.2%	0.9%	5.5%	5.5%	5.5%	5.3%	4.5%	1.1%
2015	2.1%	2.1%	-1.6%	2.0%	2.1%	2.1%	2.1%	1.9%	1.8%	-0.6%
2016	2.0%	2.0%	0.2%	1.9%	2.0%	2.0%	2.0%	1.8%	1.5%	1.8%
2017	1.6%	1.6%	1.2%	1.5%	1.6%	1.6%	1.6%	1.4%	1.2%	0.2%
2018	1.4%	1.4%	1.1%	1.2%	1.4%	1.4%	1.4%	0.6%	1.0%	-3.6%
2019	1.3%	1.3%	0.9%	1.1%	1.3%	1.3%	1.3%	-0.1%	0.9%	-0.8%
2020	1.0%	1.0%	0.7%	0.9%	1.0%	1.0%	1.0%	0.8%	0.7%	0.7%
2021	1.0%	1.0%	0.7%	0.8%	1.0%	1.0%	1.0%	0.8%	0.7%	0.7%
2022	1.1%	1.1%	0.7%	0.9%	1.1%	1.1%	1.1%	0.9%	0.9%	0.8%
2023	1.2%	1.2%	0.9%	1.1%	1.2%	1.2%	1.2%	1.0%	0.9%	0.9%
2024	1.2%	1.2%	0.8%	1.0%	1.2%	1.2%	1.2%	0.9%	0.7%	0.9%
2025	1.3%	1.3%	0.9%	1.1%	1.3%	1.3%	1.3%	1.0%	0.9%	1.0%
2026	1.2%	1.2%	0.8%	1.0%	1.2%	1.2%	1.2%	1.0%	0.9%	0.9%
2027	1.2%	1.2%	0.8%	1.0%	1.2%	1.2%	1.2%	0.9%	0.9%	0.9%
2028	1.1%	1.1%	0.8%	1.0%	1.1%	1.1%	1.1%	0.9%	0.8%	0.9%
2029	1.2%	1.2%	0.8%	1.0%	1.2%	1.2%	1.2%	0.9%	0.9%	0.8%
2030	1.2%	1.2%	0.8%	1.0%	1.2%	1.2%	1.2%	0.9%	0.9%	0.9%
2031	1.1%	1.1%	0.7%	0.9%	1.1%	1.1%	1.1%	0.9%	0.9%	0.8%
2032	1.0%	1.0%	0.7%	0.8%	1.0%	1.0%	1.0%	0.8%	0.9%	0.7%
2033	1.1%	1.1%	0.7%	0.8%	1.1%	1.1%	1.1%	0.8%	0.9%	0.6%
2034	1.0%	1.0%	0.7%	0.7%	1.0%	1.0%	1.0%	0.8%	0.8%	0.5%
2035	1.0%	1.0%	0.5%	0.6%	1.0%	1.0%	1.0%	0.8%	0.8%	0.5%
2036	1.1%	1.1%	0.4%	0.7%	1.1%	1.1%	1.1%	0.9%	0.9%	0.5%
2037	1.2%	1.2%	1.1%	1.0%	1.2%	1.2%	1.2%	0.9%	1.1%	0.7%
2038	1.1%	1.1%	1.1%	1.0%	1.1%	1.1%	1.1%	0.9%	1.0%	0.6%
2039	1.1%	1.1%	1.0%	1.0%	1.1%	1.1%	1.1%	0.9%	1.0%	0.8%

General inflation…
WM Inflation

YEAR	RATE
2013	2.4%
2014	3.0%
2015	2.0%
2016	2.0%
2017	2.0%
2018	2.0%
2019	2.0%
2020	2.0%
2021	2.0%
2022	2.0%
2023	2.0%
2024	2.0%
2025	2.0%
2026	2.0%
2027	2.0%
2028	2.0%
2029	2.0%
2030	2.0%
2031	2.0%
2032	2.0%
2033	2.0%
2034	2.0%
2035	2.0%
2036	*2.0%*
2037	*2.0%*
2038	*2.0%*
2039	*2.0%*

RESOURCE PLAN

This section of the IRP covers:

- An overview of the resource planning analysis;
- The proposed plan;
- EGEAS input assumptions;
- Carbon Scenarios in the analysis;
- Sensitivity cases under varied input assumptions;
- EGEAS modeling results;
- Robustness of the proposed plan;
- Energy balance by fuel type;
- Carbon emission projections over time;
- Justification of long term heat rates and availabilities; and,
- Drought and high water temperature risks.

6.0 Overview of Analyses

Initially, IPL creates a chart for the study period comparing the system demand load forecast plus reserve obligations to existing generating capability before resource additions. This chart gives an indication of the amount of new resources required in the future. A graph of this data can be found in Appendix 6A (and numerically in Appendix 10B).

IPL faces an expected shortfall for 2015 and 2016. The 2015 shortfall is projected to be 96 Zonal Resource Credits (ZRCs) and the 2016 shortfall is projected to be 180 ZRCs. In 2017 the MGS is expected to be in-service, relieving capacity shortfalls through 2021. For 2022 through 2024 a shortfall in the range of 25 to 84 ZRCs is shown. This brief 2022 through 2024 shortfall is essentially due to load growth. After 2024, significant shortfalls of several hundred ZRCs are shown through the end of the study period. In 2025 the shortfall is 391 ZRCs, which grows to 659 ZRCs in 2029. This is a result of load growth, retirement of existing coal units, and retirement of existing peaking units.

To meet future requirements, IPL evaluated many possible resources. On the supply-side, several different technologies are evaluated. Specifically modeled were options such as renewables, fossil-fueled technologies and market purchases. The bulk of the analysis is done using EGEAS. In an attempt to reach the best solution, numerous EGEAS runs are made, and each run looked at many plans.

The proposed plan evolved from runs that (along with IPL's existing resources), optionally had available the following resources:

- Wind
- Biomass
- Biogas
- Solar
- Simple Cycle
- Combined Cycle

- Integrated Gasification Combined Cycle
- Pulverized Coal
- Nuclear
- Purchased Power

These EGEAS runs looked at many potential plans. The optimum plan is based on having the lowest cumulative present worth given the assumptions for the 15-year study period plus a 35-year extension period.

As further background and as documented in previous resource plans, IPL has subjectively grouped its coal fired generating units into three tiers: Tier 1, Tier 2, and Tier 3.

Tier 1 units are:

- Expected to operate throughout the 15 year study period, but not all the way into the extension period;
- Expected to get full controls for NO_x, SO_2, and Hg;
- Candidates for efficiency upgrades to improve heat rate and lower emissions; and
- Tier 1 units are: Neal Units 3 and 4, Louisa, Ottumwa, and Lansing Unit 4.

Tier 2 units are:

- Generally smaller, older and less efficient than Tier 1 units;
- Not likely to economically withstand full environmental controls;
- Potentially able to withstand low-cost emissions control options; and

[TRADE SECRET DATA BEGINS

- Tier 2 units are:

TRADE SECRET DATA ENDS]

Tier 3 units are:

- Not able to withstand any additional emissions control expenditures;
- Not planned to operate throughout the study period;
- Tier 3 units, with the exception of Sutherland 3, which has been converted to gas, were proposed to be retired in the 2010 Resource Plan. IPL no longer has any Tier 3 coal-fired units remaining in its fleet for planning purposes.

<u>6.1 Proposed Plan</u>

IPL's plan to meet the demands of its customers requires modification to existing resources and new additions. The proposed resource plan includes:

- Using existing owned generation with the exceptions of proposed retirements, in the near term, of the units noted below:

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

- Implementing Ottumwa Generating Station capacity and efficiency upgrades as proposed in the 2010 Resource Plan, as well as a Scrubber and Baghouse installed by the end of 2014. For modeling purposes, a potential 2020 SCR is assumed, but no formal decision has been made;
- Implementing Lansing Unit 4 capacity and efficiency upgrades through 2017 as proposed in the 2010 Resource Plan, as well as a Scrubber installed by mid-2015 in addition to the existing SCR and Baghouse installation;
- Modifications at MidAmerican Energy Company (MidAmerican) operated units Neal 3, Neal 4, and Louisa as proposed by MidAmerican
- Complete a fuel switch at Kapp 2 from coal to natural gas in the spring of 2015. For modeling purposes, Kapp 2 is assumed to be retired in 2025, but no formal decision has been made.

[TRADE SECRET DATA BEGINS

- The installation of

TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS

- The installation of

TRADE SECRET DATA ENDS]

- The completion of the approximate 650 MW MGS combined cycle plant in the second quarter of 2017;
- A fuel switch for the Sutherland CTs from oil to natural gas preceding the installation of the MGS.
- The purchase of short term capacity in 2015 and 2016 as needed before the installation of the new combined cycle unit;
- Using forecasted DSM;
- In the long term:

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

- o Adding incremental renewable generation (for example, the reference cases for all Carbon scenarios select 1,100 MW of wind);
- o Adding new generating units (for example, the reference cases for all Carbon scenarios select a nominal 600 MW combined cycle plant in 2025);
- o Satisfy the Minnesota Solar Energy Standard;
- o For modeling purposes, the Sutherland CTs 1, 2 and 3 are assumed to retire in 2028, but no formal decision has been made;
- o For modeling purposes, Red Cedar CT is assumed to retire in 2027, but no formal decision has been made; and
- o Completing existing purchase power contracts, and evaluate possible extensions of wind and nuclear contracts;

IPL will seek MISO approval to remove the proposed retiring generating units from the MISO grid via an Attachment Y filing. For accounting purposes, subsequent to MISO approval to remove the assets from the grid, and IPL ceasing operations of the unit, IPL will retire/remove the assets from its accounting records as prescribed by the FERC Code of Federal Regulations. IPL will potentially incur future removal and environmental costs for the above referenced generating unit assets; the estimated costs and timing of such are uncertain at this time.

IPL's latest filed Depreciation Study is provided in Appendix 6N.

6.2 Transmission Congestion

Transmission congestion in the IPL service territory is primarily a result of factors or combination of factors in the real-time operational time frame. These factors include generation and transmission outages, exports from third-party generation located in the IPL service territory selling to entities outside of the IPL service territory, and regional power flows through the IPL service territory resulting from short term economy power purchases of entities outside the IPL service territory.

In 2007, the following IPL transmission facilities located in the IPL service territory were congested, requiring reductions of energy in order to alleviate the congestion:

Arnold – Vinton 161 kV on one occasion; and
Fox Lake – Rutland 161 kV on two occasions.

On all occasions, congestion relief was accomplished through generation re-dispatch and there was no loss of service to IPL customers.

In December 2007, IPL sold its transmission assets to ITC Midwest LLC (ITC-M). As a result of that transaction, IPL no longer owns transmission facilities (defined as all facilities with an operating voltage of 34 kV and above). In 2008, the following ITC-M transmission facilities located in the IPL service territory were congested, requiring reductions of energy in order to alleviate the congestion:

Fox Lake – Rutland 161 kV on two occasions;

Worth County – Hayward 161 kV on one occasion; and
Hazleton 345/161 kV transformer on one occasion.

On all occasions, congestion relief was accomplished through generation re-dispatch and there was no loss of service to IPL customers.

In 2009, the following IPL generators were re-dispatched to a higher or lower output due to transmission system congestion:

Lime Creek CT 1;
Emery on two occasions;
Sutherland Unit 2;
Sutherland Unit 3;
Sutherland CT 1;
Sutherland CT 2;
Sutherland CT 3; and
Lansing Unit 4.

On all occasions, the re-dispatch was used to mitigate the transmission congestion, and there was no loss of service to IPL customers.

In 2010, the following IPL generators were re-dispatched on one occasion to a higher or lower output due to transmission system congestion:

Prairie Creek Unit 4;
Emery;
ML Kapp Unit 2; and
Ottumwa.

On all occasions, the re-dispatch was used to mitigate the transmission system congestion, and there was no loss of service to IPL customers.

In 2011, the following IPL generators were re-dispatched to a higher or lower output due to transmission system congestion:

Prairie Creek Unit 4 on one occasion;
ML Kapp Unit 2 on one occasion;
Dubuque 8th Street Unit 4 on one occasion;
Marshalltown CT 1 on one occasion;
Marshalltown CT 3 on one occasion;
Ottumwa on two occasions; and
Emery on four occasions.

On all occasions, the re-dispatch was used to mitigate the transmission system congestion, and there was no loss of service to IPL customers.

In 2012, the following IPL generators were re-dispatched to a higher or lower output due to transmission system congestion:

Ottumwa on three occasions,
Centerville CT 1 on one occasion;
Centerville CT 2 on one occasion;
ML Kapp Unit 2 on two occasions;
Burlington on three occasions;
Neal 3 on two occasions;
Neal 4 on two occasions;
Louisa on two occasions; and

Sutherland Unit 3 on one occasion.

On all occasions, the re-dispatch was used to mitigate the transmission system congestion, and there was no loss of service to IPL customers.

In 2013, the following IPL generators were re-dispatched to a higher or lower output due to transmission system congestion:

WWE on seven occasions;
Lansing 4 on four occasions;
Burlington on one occasion;
Marshalltown CT 1 on one occasion;
Marshalltown CT 2 on one occasion;
Ottumwa on five occasions; and
Dubuque 4 on one occasion.

IPL continues to work with ITC-M through the stakeholder process to ensure a reliable supply of energy exists for its customers by continually assessing the current and future needs of the ITC-M transmission system. In addition, IPL continues to be active in the MISO Transmission Dependent Utility (TDU) sector of the planning and stakeholder process, as well as various other ad hoc transmission activities. Although past congestion has, on several occasions, resulted in IPL having to re-dispatch generation in order to help alleviate transmission congestion, IPL has no indication that its generation resources will not be able to meet customer electric demands because of transmission congestion.

6.3 EGEAS Input Assumptions

The following sections highlight the major EGEAS assumptions in the 2014 Electric Integrated Resource Plan.

6.3.1 General EGEAS Settings

Highlights of general EGEAS settings include:

- 2014-2029 Study Period with 35-year extension period;
- 7.44% discount rate (After Tax Weighted Allocated Cost of Capital per last approved rate case);
- 2013 Base Year; and
- 7.3% UCAP Planning Reserve Margin over MISO coincident peak with transmission losses (or for modeling purposes 9.98% Planning Reserve Margin over MISO coincident peak before 2.5% transmission losses).

6.3.2 Demand and Energy Forecast

See Section 2 for a detailed discussion of the load forecast development. In previous IRPs, the EGEAS system demand (MW) was modeled on an Adjusted Firm basis after reducing the system peak by interruptible load, load control, and a Demand Diversity component due to IPL's joint dispatching with

Central Iowa Power Cooperative (CIPCO). For clarity in this Resource Plan, IPL has modeled in EGEAS reductions for firm load, coincident peak and transmission losses as Demand Side Resources.

IPL developed a Base, Low, and High load forecast shown in the tables below. The Base Forecast grows by 430 MW over the study period, with ZRC obligations growing 399.3. The High Forecast grows by 703 MW, with ZRC obligations growing 682. The Low Forecast grows by 174.5 MW, with ZRC obligations growing 160.2. Note that this provides a wider bandwidth of forecast range than previous resource plans.

Expanding Interruptible and Direct Load Control (DLC) programs are modeled in EGEAS as demand-side resources. Appendix 6O contains information on Minnesota Demand Response programs. In short, Minnesota Demand Response potential is included in EGEAS modeling.

Table 6.3.2.1: EGEAS Demand and Energy Forecast, Base Forecast

Year	IPL Energy, GWH	IPL Internal Peak Demand (with TM losses)	load factor	reduction for MISO Coincident (96.44%)	reduction for 2.49% TM losses (added later)	Demand Resources, Interruptible	Demand Resources, Direct Load Control	Adj Net MISO Coincident Demand w/o TM losses	Weighted LBA TM losses	MISO Planning Reserve Margin	ZRC Obligation	EGEAS Reserve Margin: ZRC obligation / IPL adj net MISO Coincident Peak - 1
2014	16928	3121.3	62%	-111.1	-75.0	-263.3	-38.5	2633.4	2.50%	7.30%	2896.2	9.9791%
2015	17115	3151.7	62%	-112.2	-75.7	-265.4	-39.0	2659.4	2.50%	7.30%	2924.8	9.9791%
2016	17274	3179.1	62%	-113.2	-76.3	-267.5	-39.5	2682.5	2.50%	7.30%	2950.2	9.9791%
2017	17428	3205.7	62%	-114.1	-77.0	-269.6	-40.0	2705.0	2.50%	7.30%	2974.9	9.9791%
2018	17585	3232.8	62%	-115.1	-77.6	-271.8	-40.5	2727.7	2.50%	7.30%	2999.9	9.9791%
2019	17728	3257.6	62%	-116.0	-78.2	-274.0	-41.0	2748.4	2.50%	7.30%	3022.6	9.9791%
2020	17884	3284.6	62%	-116.9	-78.9	-276.2	-41.5	2771.1	2.50%	7.30%	3047.6	9.9791%
2021	18041	3311.8	62%	-117.9	-79.5	-278.4	-42.0	2794.0	2.50%	7.30%	3072.8	9.9791%
2022	18200	3339.3	62%	-118.9	-80.2	-280.6	-42.5	2817.1	2.50%	7.30%	3098.3	9.9791%
2023	18360	3368.8	62%	-119.9	-80.9	-282.8	-43.0	2842.1	2.50%	7.30%	3125.7	9.9791%
2024	18522	3398.5	62%	-121.0	-81.6	-285.1	-43.5	2867.2	2.50%	7.30%	3153.4	9.9791%
2025	18685	3428.4	62%	-122.1	-82.3	-287.4	-44.0	2892.6	2.50%	7.30%	3181.3	9.9791%
2026	18850	3458.6	62%	-123.1	-83.1	-289.7	-44.5	2918.2	2.50%	7.30%	3209.5	9.9791%
2027	19016	3489.1	62%	-124.2	-83.8	-292.0	-45.0	2944.1	2.50%	7.30%	3237.9	9.9791%
2028	19184	3519.9	62%	-125.3	-84.5	-294.3	-45.5	2970.2	2.50%	7.30%	3266.6	9.9791%
2029	19353	3550.9	62%	-126.4	-85.3	-296.7	-46.0	2996.5	2.50%	7.30%	3295.5	9.9791%

Entered in EGEAS ORT file

Modeled in EGEAS as demand side resources.

EGEAS Net Load

EGEAS Reserve Margin Requirement (applies to Net Load)

Table 6.3.2.2: High Forecast

Year	IPL Energy, GWH	IPL Internal Peak Demand (with TM losses)	load factor	reduction for MISO Coincident (96.44%)	reduction for 2.49% TM losses (added later)	Demand Resources, Interruptible	Demand Resources, Direct Load Control	Adj Net MISO Coincident Demand w/o TM losses	Weighted LBA TM losses	MISO Planning Reserve Margin	ZRC Obligation	EGEAS Reserve Margin: ZRC obligation / IPL adj net MISO Coincident Peak - 1
2014	16928	3121.3	62%	-111.1	-75.0	-263.3	-38.5	2633.4	2.50%	7.30%	2896.2	9.9791%
2015	17200	3167.3	62%	-112.8	-76.1	-265.4	-39.0	2674.0	2.50%	7.30%	2940.9	9.9791%
2016	17445	3210.6	62%	-114.3	-77.1	-267.5	-39.5	2712.2	2.50%	7.30%	2982.9	9.9791%
2017	17688	3253.6	62%	-115.8	-78.1	-269.6	-40.0	2750.0	2.50%	7.30%	3024.4	9.9791%
2018	17936	3297.3	62%	-117.4	-79.2	-271.8	-40.5	2788.4	2.50%	7.30%	3066.7	9.9791%
2019	18171	3339.1	62%	-118.9	-80.2	-274.0	-41.0	2825.0	2.50%	7.30%	3107.0	9.9791%
2020	18422	3383.5	62%	-120.5	-81.2	-276.2	-41.5	2864.1	2.50%	7.30%	3149.9	9.9791%
2021	18676	3428.5	62%	-122.1	-82.3	-278.4	-42.0	2903.7	2.50%	7.30%	3193.4	9.9791%
2022	18934	3474.1	62%	-123.7	-83.4	-280.6	-42.5	2943.9	2.50%	7.30%	3237.6	9.9791%
2023	19195	3522.1	62%	-125.4	-84.6	-282.8	-43.0	2986.3	2.50%	7.30%	3284.3	9.9791%
2024	19461	3570.7	62%	-127.1	-85.7	-285.1	-43.5	3029.3	2.50%	7.30%	3331.6	9.9791%
2025	19729	3620.1	62%	-128.9	-86.9	-287.4	-44.0	3072.9	2.50%	7.30%	3379.5	9.9791%
2026	20002	3670.1	62%	-130.7	-88.1	-289.7	-44.5	3117.1	2.50%	7.30%	3428.1	9.9791%
2027	20278	3720.8	62%	-132.5	-89.3	-292.0	-45.0	3162.0	2.50%	7.30%	3477.5	9.9791%
2028	20558	3772.2	62%	-134.3	-90.6	-294.3	-45.5	3207.5	2.50%	7.30%	3527.6	9.9791%
2029	20842	3824.3	62%	-136.2	-91.8	-296.7	-46.0	3253.6	2.50%	7.30%	3578.3	9.9791%

Entered in EGEAS ORT file

Modeled in EGEAS as demand side resources.

EGEAS Net Load

EGEAS Reserve Margin Requirement (applies to Net Load)

Table 6.3.2.3: Low Forecast

Year	IPL Energy, GWH	IPL Internal Peak Demand (with TM losses)	load factor	reduction for MISO Coincident (96.44%)	reduction for 2.49% TM losses (added later)	Demand Resources, Interruptible	Demand Resources, Direct Load Control	Adj Net MISO Coincident Demand w/o TM losses	Weighted LBA TM losses	MISO Planning Reserve Margin	ZRC Obligation	EGEAS Reserve Margin: ZRC obligation / IPL adj net MISO Coincident Peak - 1
2014	16928	3121.3	62%	-111.1	-75.0	-263.3	-38.5	2633.4	2.50%	7.30%	2896.2	9.9791%
2015	17031	3136.1	62%	-111.7	-75.3	-265.4	-39.0	2644.7	2.50%	7.30%	2908.6	9.9791%
2016	17103	3147.6	62%	-112.1	-75.6	-247.0	-33.7	2679.3	2.50%	7.30%	2946.7	9.9791%
2017	17170	3158.2	62%	-112.4	-75.8	-250.0	-34.0	2686.0	2.50%	7.30%	2954.0	9.9791%
2018	17239	3169.1	62%	-112.8	-76.1	-252.0	-34.3	2693.9	2.50%	7.30%	2962.7	9.9791%
2019	17293	3177.6	62%	-113.1	-76.3	-255.0	-34.7	2698.5	2.50%	7.30%	2967.8	9.9791%
2020	17359	3188.1	62%	-113.5	-76.6	-257.0	-35.0	2706.0	2.50%	7.30%	2976.0	9.9791%
2021	17424	3198.6	62%	-113.9	-76.8	-260.0	-35.4	2712.5	2.50%	7.30%	2983.2	9.9791%
2022	17491	3209.1	62%	-114.3	-77.1	-263.0	-35.7	2719.1	2.50%	7.30%	2990.4	9.9791%
2023	17557	3221.4	62%	-114.7	-77.4	-265.0	-36.1	2728.3	2.50%	7.30%	3000.5	9.9791%
2024	17624	3233.7	62%	-115.1	-77.7	-268.0	-36.5	2736.4	2.50%	7.30%	3009.5	9.9791%
2025	17692	3246.0	62%	-115.6	-77.9	-271.0	-36.8	2744.7	2.50%	7.30%	3018.6	9.9791%
2026	17759	3258.4	62%	-116.0	-78.2	-273.0	-37.2	2754.0	2.50%	7.30%	3028.8	9.9791%
2027	17827	3270.8	62%	-116.5	-78.5	-276.0	-37.6	2762.3	2.50%	7.30%	3037.9	9.9791%
2028	17895	3283.3	62%	-116.9	-78.8	-279.0	-37.9	2770.6	2.50%	7.30%	3047.1	9.9791%
2029	17963	3295.8	62%	-117.3	-79.1	-282.0	-38.3	2779.0	2.50%	7.30%	3056.4	9.9791%

Entered in EGEAS ORT file

Modeled in EGEAS as demand side resources.

EGEAS Net Load

EGEAS Reserve Margin Requirement (applies to Net Load)

6.3.3 Emissions Costs

In the No Carbon and Wood Mackenzie 2023 Carbon scenarios, emission costs for SO_2 and NO_x are based on Wood Mackenzie projections. However, due to significant fleet changes resulting from regulations such as MATS triggering retrofits, fuel switching, and retirements of units, Wood Mackenzie's SO_2 and NO_x prices are $0 indicating a significant supply surplus expected for future trading.

The Minnesota Midpoint 2017 Carbon scenario uses Emissions Costs based on the midpoint of the low and high externality values established in the Commission's June 5, 2013, Notice of Updated Environmental Externality Values in Docket No. CI-00-1636. As IPL's generating plants are located outside of Minnesota (with the exception of Fox Lake and Hills Diesels), IPL uses the externality values for "Within 200 Miles of Minnesota." Costs are inflated annually by general inflation rate noted in Appendix 5D. 2013 dollar per ton costs are noted in the table below. Note that SO_2 and NO_x costs are internalized in the model (added to dispatch cost calculations when prioritizing the supply stack, as opposed to added after dispatch).

Table 6.3.3.1: Minnesota Midpoint 2017 Carbon Scenario Emissions Costs, 2013 $/ton

Emission	Dispatch Calculation Impact	Low	High	Midpoint
SO_2	Internalized	10.20	25.50	17.85
NO_x	Internalized	25.50	146.88	86.19
PM_{10}	Externalized	807.84	1,230.12	1,018.98
CO	Externalized	0.31	0.59	0.45
Pb	Externalized	578.34	644.64	611.49
CO_2*	Externalized	0	0	0

*$0 CO_2 externality value, see below for 2017 internalized values for various sensitivities

For this 2014 IRP, IPL performed sensitivity analysis under three sets of Carbon monetization assumptions: No Carbon, Wood Mackenzie 2023 Carbon, and Minnesota Midpoint 2017 Carbon. As a result, there is no longer one base case. Instead there are three sets of carbon scenarios with sensitivities for each scenario.

The No Carbon scenario sets CO_2 prices at $0/ton in all years. The Wood Mackenzie 2023 Carbon scenario sets CO_2 prices at $16/ton in 2023 per Wood Mackenzie's Spring 2013 Long Term Outlook[2] with a heavy escalation rate.

---

[2] Full data for Wood Mackenzie's Fall 2013 Long Term Outlook not available in time for this resource plan.

The Minnesota Midpoint 2017 Carbon scenario sets prices at the midpoint of the Commission's November 2, 2012, Order Establishing 2012 and 2013 Estimate of Future Carbon Dioxide Regulation Costs in Docket No. E-999/CI-07-1199, establishing that utilities should begin applying a range of $9 and $34 per ton for carbon values in resource planning as of 2017. Additionally, the Minnesota Carbon scenario includes "one-off" sensitivities for the low and high range of CO_2 costs. The CO_2 prices modeled are shown in Table 6.3.3.2 below:

Table 6.3.3.2: CO_2 Prices, $/Ton

Year	No Carbon Scenario	Wood Mackenzie 2023 Carbon Scenario	Minnesota Midpoint 2017 Carbon Scenario		Sensitivity: Minnesota Low CO_2 $/Ton	Sensitivity: Minnesota High CO_2 $/Ton
2014	$0.00	$0.00	$0.00		$0.00	$0.00
2015	$0.00	$0.00	$0.00		$0.00	$0.00
2016	$0.00	$0.00	$0.00		$0.00	$0.00
2017	$0.00	$0.00	$21.40		$8.96	$33.85
2018	$0.00	$0.00	$21.83		$9.14	$34.52
2019	$0.00	$0.00	$22.27		$9.32	$35.21
2020	$0.00	$0.00	$22.71		$9.51	$35.92
2021	$0.00	$0.00	$23.17		$9.70	$36.64
2022	$0.00	$0.00	$23.63		$9.89	$37.37
2023	$0.00	$16.01	$24.10		$10.09	$38.12
2024	$0.00	$17.31	$24.59		$10.29	$38.88
2025	$0.00	$18.72	$25.08		$10.50	$39.66
2026	$0.00	$20.24	$25.58		$10.71	$40.45
2027	$0.00	$21.88	$26.09		$10.92	$41.26
2028	$0.00	$23.66	$26.61		$11.14	$42.08
2029	$0.00	$25.58	$27.14		$11.36	$42.93
2030	$0.00	$27.65	$27.69		$11.59	$43.78
2031	$0.00	$29.90	$28.24		$11.82	$44.66
2032	$0.00	$32.33	$28.81		$12.06	$45.55
2033	$0.00	$34.95	$29.38		$12.30	$46.46
2034	$0.00	$37.79	$29.97		$12.55	$47.39
2035	$0.00	$45.04	$30.57		$12.80	$48.34

6.3.4 Natural Gas, Coal, Market Energy, and Market Capacity Costs

Natural gas costs are based on Wood Mackenzie projections, which can be found in Appendix 6B for the Carbon and No-Carbon scenarios. Natural gas prices are shown for Emery, which is the same as a new generic combined cycle or combustion turbine. Pricing for other existing natural gas-fired units use the same trajectory with the starting values noted in Appendix 6C.

Long term coal fuel costs are based on Wood Mackenzie projections. IPL assumed a ramp-up of coal costs between 2014 and 2016, starting with 2013 actuals to 2017 Wood Mackenzie values. This ramp-up acknowledges the transition from expiring legacy contracts. Coal prices are provided in Appendix 6B.

Market Economy Energy Costs are based on Wood Mackenzie projections, and shown in Appendix 6B. The EGEAS modeling allows 400 MW of Market Energy at Off Peak prices, and 400 MW of Market Energy at On Peak prices through 2016. In 2017 these values are reduced to 133 MW each (a reduction to one third) to avoid over-reliance on Market Energy and potential fluctuation exposure. This results in Market Energy contributing 5% or less to the long term annual energy portfolio. For this resource plan, IPL limited Off Peak Market Energy to be available only during Off Peak times. Note that these market energy limitations are a significant reduction from previous IPL Resource Plans.

Market Capacity Costs are based on Wood Mackenzie projections, and shown in Appendix 6B. Beginning with 2017, coinciding with the MGS combined cycle addition; one-year peak power purchases are limited to 150 ZRCs per year. These market capacity purchases are represented in EGEAS as one-year peak power purchases with no energy.

6.3.5 Capital and O&M Change Rates

General Capital and Operations & Maintenance (O&M) Change Rates are noted in Appendix 5D.

6.3.6 New Generic Units

New Generic Unit costs and parameters are noted in Appendix 5C. Much of this data comes from the 2013 Power Station Characterization Study performed by Black & Veatch.

6.3.7 Wind Pricing and Availability

Wind pricing in this Resource Plan was based on new facility data per the 2013 Black & Veatch Power Station Characterization Study. See Appendix 5C for breakdown of costs and operating parameters. IPL estimates these costs at roughly $45/MWH on a levelized basis for a 2013 installation.

IPL allowed 100 MW per year of new, 41% capacity factor, generic wind to be added in the expansion plan, up to a total of 1,100 MW. The new generic wind combined with IPL's existing wind resources allows up to 25% of the energy portfolio to come from wind. In addition, the superfluous unit setting in EGEAS was set to 10 for the generic 100 MW wind alternative.

The 25% wind energy contribution limit is used to acknowledge the significant transmission upgrades needed to facilitate heavy wind penetration, which is supported by other studies. For example, 25% was the upper penetration level used in the 2006 Minnesota Wind Integration Study.[3] Further, the 2011 MISO Transmission Expansion Plan (2011 MTEP) notes "The recent adoption of Renewable Portfolio Standards (RPS) across the MISO footprint have driven the need for a more regional and robust transmission system to deliver renewable resources from often remote renewable energy generators to load centers."[4] The 2011 MTEP also notes, "To meet the various policy objectives, all scenarios … require significant investment in generation and transmission expansion across the 15-year study horizon."[5] However, as shown in the table below, none of the scenarios in the 2011 MTEP accommodate 25% wind penetration. The maximum penetration in the 2011 MTEP is roughly 20%.

Table 6.3.7.1: 2011 MTEP Scenario Results[6]

Scenario	Scenario Renewable Requirements	Renewable / Wind Additions by 2026	Annual Renewable/ Wind Energy Output by 2026	2026 Retail Rate Impact
Business-As-Usual with Mid-low Demand and Energy Growth Rates	State RPS	23,900 MW	16%	-1.2%
Business-As-Usual with Historic Demand and Energy Growth Rates	State RPS	26,800 MW	16%	+2.1%
Carbon Constraint	State RPS	21,000 MW	16%	+14.7%
Combined Energy Policy	Federal 20% RPS	28,800 MW	21%	+18.6%

6.3.8 Nuclear Purchases

IPL assumed a 400 MW PPA renewal from the DAEC for 2014-2025, and continues this purchase through the end of the plant's licensed life in 2034 (outside the EGEAS study period). IPL presumes that as long as the plant continues to run IPL is a potential buyer. However, pricing is of particular concern and will need to be negotiated. IPL anticipates that similar to the efforts taken in previous years which resulted in a Requested for Proposals, it will undertake similar bidding processes to ensure competitive value for customers before the expiration of the now-effective PPA.

[3] Prepared for the Minnesota Public Utilities Commission by EnerNex Corporation in collaboration with MISO (f/k/a Midwest Independent Transmission System Operator, Inc.), http://www.puc.state.mn.us/portal/groups/public/documents/pdf_files/000435.pdf
[4] https://www.midwestiso.org/Library/Repository/Study/MTEP/MTEP11/MTEP11%20Report.pdf page 44.
[5] *Ibid*, page 33.
[6] *Ibid*, pages 34-38, and follow-up email between IPL and MISO.

6.3.9 Existing Units

Appendix 6C lists IPL's Existing Generating Units, as well as purchases and sales. Appendix 6C also provides the modeled 2014 Zonal Resource Credits under the MISO Module E Resource Adequacy construct and dispatch parameters

The following sections highlight changes to existing units such as emission controls[7], capacity and efficiency upgrades, and retirements. Appendix 6D shows projected cost and operating parameters for the Tier 1 and Tier 2 coal-fired units. Note that the costs shown are in 2013 dollars. IPL will provide the Appendix 6D Microsoft Excel spreadsheet. The Excel file has additional rows to demonstrate how costs are converted to nominal values for EGEAS entry.

6.3.9.1 Ottumwa

The Ottumwa plant was modeled with:

- A Scrubber and Baghouse installed by 2015 to reduce sulfur dioxide (SO2), mercury (Hg), and particulate matter (PM) emissions to comply with the MATS and a rule similar to the Clean Air Interstate Rule (CAIR).
- Potential NOx control installed by 2020. This control is a modeling assumption, though not required to comply with existing emission regulations. This assumption was included as a placeholder for compliance with potential emission regulations consistent with IPL's approach of having full controls at Tier I units. [TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]
- Turbine upgrade and capacity/efficiency upgrades by 2015.
- Various other costs to comply with coal combustion residuals (CCR) and water rules, such as 316(b) and effluent limitation guidelines.

6.3.9.2 Lansing

The Lansing 4 plant was modeled with:

- An SCR and Baghouse installed by 2010 to reduce NO_x, Hg, and PM emissions to comply with MATS and a CAIR-like rule.
- A Scrubber installed by 2016 to reduce SO_2 emissions to comply with a CAIR-like rule.
- Turbine upgrade and capacity/efficiency upgrades through 2017.
- Various other costs to comply with CCR and water rules including 316(a) and (b) and effluent limitation guidelines.

---

[7] Environmental regulations are discussed in section 7.5.

6.3.9.3 Louisa and Neal Units 3 and 4

IPL is a minority owner in Louisa and Neal Units 3 and 4 (4%, 28% and 25.695% respectively), while MidAmerican operates the units. For MATS compliance on these units, IPL assumed the additions of:

- Activated Carbon Injection controls by 2015 to reduce mercury at Louisa.
- Scrubber, Selective Non-Catalytic Reduction, and Activated Carbon Injection controls by 2015 to reduce SO_2, NO_x, and Hg at Neal 3.
- Activated Carbon Injection controls by 2014 to reduce Hg at Neal 4.

6.3.9.4 Tier 2 Coal Fired Units

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

The EGEAS modeling for Kapp 2 assumes a 2015 fuel switch to natural gas operation, with a significant de-rate to capacity. [TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

The EGEAS modeling for [TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

6.3.9.5 Intermediate Unit Retirements

IPL plans to retire several intermediate units, some of which were identified in the 2010 Resource Plan. These units are older, smaller, less-efficient steam units that when constructed, operated on coal and have since been converted to natural gas as their primary fuel. [TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS] Table 6.3.9.5 below summarizes some key current information related to the steam units IPL plan to retire.

Table 6.3.9.5 - IPL Intermediate Steam Unit Retirements

[TRADE SECRET DATA BEGINS

Unit Name	Primary Fuel	Age	2014 ZRC Capacity	Proposed Retirement
				6/1/2017
				6/1/2016
				6/1/2016
				6/1/2017
				6/1/2017

TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS The TRADE SECRET DATA ENDS] as well as [TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS] were assumed to be retired by the end of [TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS] in IPL's 2010 Resource Plan. [TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]

These five steam units are all over 52 years of age, which is the typical expected life by general industry standards. IPL has maintained the equipment associated with these units for over five decades, but the equipment is showing its age as would be expected. Significant investments would be required to restore the equipment on these units to ensure long-term, reliable operation.

IPL did not conduct a comprehensive review of all projects required to restore these units to long-term reliable operation due to the sheer magnitude of equipment required to operate these units, but rather, developed a high level estimate of the key project investment for [TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS] The initial investment to restore these units would be approximately [TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS] for [TRADE SECRET DATA BEGINS [TRADE SECRET DATA BEGINS for TRADE SECRET DATA ENDS] [TRADE SECRET DATA BEGINS and TRADE SECRET DATA ENDS] TRADE SECRET DATA ENDS]. A breakdown of the costs is shown on Appendix 6E.

Because these estimates did not include the cost for every component that would need to be replaced or refurbished on these units, has an accuracy of +/-40%. It does summarize what IPL considers to be the most important projects and outlines the magnitude of the investment required to situate these units for long-term operation. Because these are older units and not all issues may be readily visible, IPL cannot easily anticipate any additional costs that could result from issues discovered once work actually begins on the units. This would result in additional expense to repair and refurbish these units.

Also, if the work triggers New Source Review, it is possible that emission control equipment or emission limits could be required, thus resulting in further expenses in addition to the costs to repair and refurbish these units.

6.3.9.6 Peaking Unit Retirements

While IPL's peaking fleet has delivered safe and reliable service to customers for decades, it is an aging fleet. In fact, each of the units was manufactured over 40 years ago. Based upon general industry standards, a life of 30 to 40 years is a reasonable assumption for peaking units. Table 6.3.9.6 below summarizes some key current information relating to the peaking units that IPL plans to retire.

Table 6.3.9.6 – IPL Peaking Unit Retirements

[TRADE SECRET DATA BEGINS

Unit Name	Primary Fuel	Age	2014 ZRC Capacity	Proposed Retirement
				6/1/2017
				6/1/2017
				6/1/2017
				6/1/2017
				6/1/2016
				6/1/2017
				6/1/2017
				6/1/2017
				6/1/2017
				6/1/2017
				6/1/2017
			TRADE SECRET DATA ENDS]	

* Indicates peaking units purchased used.

Peaking units serve three primary purposes. First, they help ensure IPL has enough planning resource credits, or capacity, to match its customers' peak demand plus a reserve margin on an annual basis. Second, they can provide support for local grid reliability during times of peak load conditions or during times when transmission system conditions dictate local support. Third, peaking resources help provide a hedge for market prices, both capacity and energy.

Because these units could be called upon during high load conditions, for transmission reliability reasons or when market prices are high, the peaking units must be sufficiently reliable to perform these intended functions, which require consistent maintenance of the units. While these units have generally been reliable over the decades, like any piece of equipment, maintaining that reliability continues to be more challenging and cost prohibitive as these units continue to age.

IPL performed a conditional assessment which evaluated the units as a whole by reviewing the current condition of key system components. IPL's inspection resulted in a determination that the [TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS] will require a significant amount of investment to restore them to a long-term, reliable operating condition. This condition review also supports IPL's position that these peaking units are at or near the end of their useful life.

IPL has developed preliminary estimates of the cost to restore its peaking units to a long-term, reliable operating condition. IPL estimates the initial cost to restore the nine peaking units to a long-term reliable operating condition would be approximately [TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS] per unit (with an accuracy of +/-40%), for a total of

[TRADE SECRET DATA BEGINS (+/- 40%). TRADE SECRET DATA ENDS] Additionally, given that these are older units and not all issues may be readily visible, IPL cannot easily anticipate or estimate additional costs that could result from issues discovered once component repair, refurbishment and replacement actually begins on these aging units. These additional, unanticipated expenses have the potential to increase the [TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS] per unit estimate outlined above. Appendix 6F is an estimate of the typical cost to restore each of the nine peaking units.

IPL's experience has also proven that acquiring some of the key replacement components for the old units is quite challenging and in some cases, almost impossible. While it may seem possible to completely repair, replace and refurbish the key components of these units, the reality is that this initiative has the potential to be very challenging.

IPL also understands it could be required to obtain an environmental permit to complete projects to repair and refurbish these peaking units. IPL believes it could be required to install additional emission control equipment on these peaking units if the work triggers New Source Review requirements. Absent a detailed understanding of the specific work required and an environmental permitting assessment of the required work, it is difficult to estimate the potential costs. However, expense for any additional emission control projects would increase the [TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS] per unit estimate outlined earlier.

For these reasons IPL did not believe it was reasonable to conduct any further detailed economic analysis associated with the complete refurbishment of these units.

6.3.9.7 Sutherland CTs Fuel Switch

Due to environmental compliance requirements resulting from the permitting for the MGS combined cycle plant, IPL will convert the Sutherland CTs from oil to natural gas-fired operations.

6.4 Scenarios

As previously explained, for this 2014 IRP, IPL performed the sensitivity analysis under three sets of Carbon monetization scenarios: (i) No Carbon; (ii) Wood Mackenzie 2023 Carbon; and (iii) Minnesota Midpoint 2017 Carbon. As a result, there is no longer one base case. Instead, there are three sets of carbon scenarios with sensitivities for each scenario.

6.5 Sensitivities

Sensitivities take the base assumptions and vary key inputs. Expansion plans and summary costs are presented for 22 sensitivities as follows:

- Base Forecast (Reference Case)
- High Load Forecast
- Low Load Forecast
- No Economy Energy
- Higher Natural Gas Fuel Prices +10%

- Higher Natural Gas Fuel Prices +20%
- Higher Natural Gas Fuel Prices +30%
- Lower Natural Gas Fuel Prices -10%
- Lower Natural Gas Fuel Prices -20%
- Lower Natural Gas Fuel Prices -30%
- Higher Coal Fuel Prices +10%
- Higher Coal Fuel Prices +20%
- Higher Coal Fuel Prices +30%
- Lower Coal Fuel Prices -10%
- Lower Coal Fuel Prices -20%
- Lower Coal Fuel Prices -30%
- Higher New Unit Capital Costs +10%
- Lower New Unit Capital Costs -10%
- Higher Wind Prices +20/MWh
- Higher Wind Prices +10/MWh
- Lower Wind Prices -10/MWh
- Lower Wind Prices -20/MWh

Expansion plans are provided in Appendix 6G. Appendix 6H provides present value cost summaries as well as total MW's of units added in the expansion plans.

Additionally, "one-off" sensitivity runs were performed for the Minnesota 2017 Carbon Scenario, including:

- High, \$34 CO_2 costs
- Low, \$9 CO_2 costs
- Externalities High
- Externalities Low
- Meeting new capacity requirements with 50% DSM and Renewables
- Meeting new capacity requirements with 75% DSM and Renewables
- SO_2 allowance cost \$1,000/ton
- SO_2 allowance cost \$2,000/ton
- No Forced Solar
- No Recent RES additions
- Varied Minnesota DSM levels

In general, the resulting expansion plans for these sensitivity runs under all carbon scenarios include the following:

- A short-term capacity purchase of 100 ZRCs in 2015 and 200 ZRCs in 2016.
- The committed installation of the MGS in 2017.

- A significant amount of wind starting in 2018 or 2019 and continuing throughout the study period, generally totaling 1100 MW.
- The minimum forced installation of 10 MW of solar in 2020. IPL enforced this minimum amount of solar to represent the impact of the Minnesota Solar Energy Standard on the expansion plan. The modeling may select additional solar if economic; however, such additional solar was not selected in any of the expansion plans.
- The addition of a nominal 600 MW 2x1 combined cycle in 2025. In some sensitivity runs, instead of a 2025 2x1 combined cycle addition, the modeling selected a 2025 combustion turbine with a 1x1 combined cycle in 2028 and several one year capacity purchases from 2025-2029. IPL views these significant gas additions late in the study period as equivalent, and believes the difference is just due to end effects near the end of the study period. In other words, the impact of load growth after 2029 is not considered.

Although the carbon scenarios did not have a significant impact to the expansion plans (at least under the Base Assumptions), the carbon scenarios did have a significant impact on cost. In fact, the carbon assumption is the largest driver in plan costs in comparison to the various sensitivity runs. The Wood Mackenzie 2023 Carbon scenario increased Present Value Revenue Requirements (PVRR) about $1.66 billion or 11% over the No Carbon Scenario. The Minnesota Midpoint 2017 Carbon scenario increased PVRR about $2.39 billion or 16% over the No Carbon Scenario.

Details of the sensitivity runs are discussed below.

6.5a Base Assumptions (Reference Cases)

The Base Assumptions Case (Reference Case) for the three carbon scenarios was based on reasonable assumptions and was built to represent a combination of assumptions that was probable at the time of plan development. Annual by-unit production costs for the three carbon scenarios are shown in Appendices 6I, 6J and 6K.

6.5.b High Load Forecast

Starting with the Reference Case assumptions, the high load forecast replaced the load forecast in the Reference Case and then existing and potential future resources were optimized. The total cumulative present worth cost of these sensitivities for the study period plus the 35-year extension (PVRR) was $973 - $1,128 million higher than the Reference Case for the various carbon scenarios. The expansion plans increased one year capacity purchases and added a 2028 combustion turbine to accommodate the higher load.

6.5c Low Load Forecast

Starting with the Reference Case assumptions, the low load forecast replaced the load forecast in the Reference Case and then existing and potential future resources were optimized. The total PVRR of these sensitivities was $946 - $1,104 million lower than the Reference Case case for the various carbon scenarios. The expansion plans dropped the 2025 combined cycle unit, and instead added a combustion turbine in 2028, with significant one year capacity purchases in the last 5 years of the study period.

6.5d No Economy Energy

Starting with the Reference Case assumptions, all energy was assumed to be served by IPL resources, that is, no market economy energy was available throughout the study period and then existing and potential future resources were optimized. The total PVRR of these sensitivities was $531 - $561 million higher than the Reference Case for the various carbon scenarios. The expansion plans did not change from the Reference Case.

6.5e Higher Natural Gas Prices

Starting with the Reference Case assumptions, existing and potential future resources were optimized with natural gas and On Peak Market Economy Energy prices starting 10, 20, and 30 percent higher in the first year, base escalations assumed thereafter. The PVRRs of these sensitivities were higher than the reference cases:

- $292-$375 million higher in the +10% sensitivity,
- $577-$677 million higher in the +20% sensitivity, and
- $859-$964 million higher in the +30% sensitivity.

Expansion plans in these sensitivity runs were not significantly different from the reference cases.

6.5f Lower Natural Gas Prices

Starting with the Reference Case assumptions, existing and potential future resources were optimized with natural gas and On Peak Market Economy Energy prices starting 10, 20, and 30 percent lower in the first year, base escalations assumed thereafter. The PVRRs of these sensitivities were lower than the reference cases:

- $316 - $457 million lower in the -10% sensitivity,
- $729 - $1,023 million lower in the -20% sensitivity, and
- $1,276 - $1,660 million lower in the -30% sensitivity.

Expansion plans in these sensitivity runs were generally not significantly different from the reference cases, with the exception of the amount of wind selected in the No Carbon cases:

- The reference cases and carbon scenario sensitivities for all low natural gas cost sensitivities selected 1,100 MW of wind in the expansion plan.

- The No Carbon Scenario -20% low natural gas cost sensitivity selected only 700 MW.
- The No Carbon Scenario -30% low natural gas cost sensitivity selected only 600 MW of wind.

The No Carbon Scenario -20% and -30% low natural gas cost sensitivities also included some amount of one year capacity purchases to make up for the capacity lost with fewer wind additions.

6.5g Higher Coal Fuel Prices

Starting with the Reference Case assumptions, existing and potential future resources were optimized with coal fuel and Off Peak Market Economy Energy prices starting 10, 20, and 30 percent higher in the first year, base escalation assumed thereafter. The PVRRs of these sensitivities were higher than the reference cases:

- $227-$338 million higher in the +10% sensitivity,
- $399-$627 million higher in the +20% sensitivity, and
- $538-$864 million higher in the +30% sensitivity.

Expansion plans in these sensitivity runs were not significantly different from the reference cases.

6.5h Lower Coal Fuel Prices

Starting with the Reference Case assumptions, existing and potential future resources were optimized with coal fuel and Off Peak Market Economy Energy prices starting 10, 20, and 30 percent lower in the first year, base escalation assumed thereafter. The PVRRs of these sensitivities were lower than the reference cases:

- $268-$360 million lower in the -10% sensitivity,
- $578-$722 million lower in the -20% sensitivity, and
- $915-$1,085 million lower in the -30% sensitivity.

Expansion plans in these sensitivity runs were not significantly different from the reference cases.

6.5i Higher New Unit Capital Costs +10%

Starting with the Reference Case assumptions, existing and potential future resources were optimized with capital costs for new generic units 10% higher in the first year, base escalation assumed thereafter. The total PVRR of these sensitivities was roughly $360 million higher than the Reference Case for the various carbon scenarios. The expansion plans did not significantly change from the Reference Case.

6.5j Lower New Unit Capital Costs -10%

Starting with the Reference Case assumptions, existing and potential future resources were optimized with capital costs for new generic units 10%

lower in the first year, base escalation assumed thereafter. The total PVRR of these sensitivities was roughly $375 million lower than the Reference Case for the various carbon scenarios. The expansion plans did not significantly change from the Reference Case.

6.5k Higher Wind Prices

Starting with the Reference Case assumptions, existing and potential future resources were optimized with new wind prices assumed $20 and $10 per MWh higher. The PVRRs of these sensitivities were higher than the reference cases:

- $300-$415 million higher in the +$10 per MWH sensitivity, and
- $376-$710 million higher in the +$20 per MWH sensitivity.

The Reference Cases of all carbon scenarios selected 1,100 MW of wind in the expansion plan, but for these higher wind price sensitivity runs:

- The No Carbon Scenario +$10/MWH sensitivity selected only 600 MW of wind. Both the Wood Mackenzie and Minnesota Midpoint carbon scenarios selected 1,100 MW.
- The No Carbon Scenario +$20/MWH sensitivity selected no wind. Both the Wood Mackenzie and Minnesota Midpoint carbon scenarios selected 600 MW.

6.5l Lower Wind Prices

Starting with the Reference Case assumptions, existing and potential future resources were optimized with new wind prices assumed $20 and $10 per MWh lower. The PVRRs of these sensitivities were lower than the reference cases:

- $413-$423 million lower in the -$10 per MWH sensitivity, and
- $836-$845 million lower in the -$20 per MWH sensitivity.

The expansion plans did not significantly change from the Reference Case.

6.5m CO_2 Scenario – Minnesota High

As a “one-off” sensitivity run performed only under the Minnesota Midpoint 2017 Carbon Scenario, this scenario evaluated carbon costs at a high $34 range. The PVRR of this sensitivity was $1,090 million higher than the Minnesota Midpoint Reference Case. The expansion plan did not change from the Minnesota Midpoint Reference Case.

6.5n CO_2 Scenario – Minnesota Low

As a “one-off” sensitivity run performed only under the Minnesota Midpoint 2017 Carbon Scenario, this scenario evaluated carbon costs at a low $9 range. The PVRR of this sensitivity was $1,462 million lower than the Minnesota Midpoint Reference Case. The expansion plan did not change from the Minnesota Midpoint Reference Case.

6.5o Externalities High

As a "one-off" sensitivity run performed only under the Minnesota Midpoint 2017 Carbon Scenario, this scenario evaluated externalities at the high range (see Table 6.3.3.1). The PVRR of this sensitivity was only $7 million higher than the Minnesota Midpoint Reference Case. The expansion plan did not change from the Minnesota Midpoint Reference Case. Note that this small variation is essentially statistically insignificant for resource planning purposes.

6.5p Externalities Low

As a "one-off" sensitivity run performed only under the Minnesota Midpoint 2017 Carbon Scenario, this scenario evaluated externalities at the low range (see Table 6.3.3.1). The PVRR of this sensitivity was only $6 million lower than the Minnesota Midpoint Reference Case. The expansion plan did not change from the Minnesota Midpoint Reference Case. Note that this small variation is essentially statistically insignificant for resource planning purposes.

6.5q 50% DSM and Renewables

As a "one-off" sensitivity run performed only under the Minnesota Midpoint 2017 Carbon Scenario, this scenario evaluated meeting 50% of new capacity requirements with additional DSM and renewables. The PVRR of this sensitivity was $270 million higher than the Minnesota Midpoint Reference Case. The expansion plan included MGS as a committed unit, 1,100 MW of wind, several one year capacity purchases, a 2025 CT, 300 MW of solar, and 100 MW of landfill gas.

6.5r 75% DSM and Renewables

As a "one-off" sensitivity run performed only under the Minnesota Midpoint 2017 Carbon Scenario, this scenario evaluated meeting 75% of new capacity requirements with additional DSM and renewables. The PVRR of this sensitivity was $561 million higher than the Minnesota Midpoint Reference Case. The expansion plan included MGS as a committed unit, 1,100 MW of wind, several one year capacity purchases, 600 MW of solar, and 100 MW of landfill gas.

6.5s SO2 Allowance Cost Variations

As "one-off" sensitivity runs performed only under the Minnesota Midpoint 2017 Carbon Scenario, IPL varied SO_2 costs from the Reference Case. In the Reference Case SO_2 costs are very low, near zero values. A $1,000/ton SO2 allowance cost increased PVRR $71 million, and a $2,000/ton SO_2 allowance cost increased PVRR $136 million. The expansion plans did not change from the Minnesota Midpoint Reference Case.

6.5t No Forced Solar

As a "one-off" sensitivity run performed only under the Minnesota Midpoint 2017 Carbon Scenario, IPL removed the expansion plan requirement that a minimum of 10 MW of solar be added by 2020 to represent compliance with the

Minnesota Solar Energy Standard. This reduced the PVRR $17 million, but did not otherwise significantly impact the expansion plan.

6.5u No Recent Renewable Energy Standard Additions

As a "one-off" sensitivity run performed only under the Minnesota Midpoint 2017 Carbon Scenario, IPL removed the recent major wind additions of Whispering Willow Windfarm, Hardin Hilltop, and Junction Hilltop. PVRR increased $96M, and the expansion plan did not change from the Minnesota Midpoint Reference Case.

6.5v Minnesota DSM Analysis

The Minnesota DSM analysis was performed to evaluate what level of DSM is most appropriate for Minnesota. These scenarios test different levels of Minnesota DSM highlighted below, and discussed in more detail in Section 3:

- Base – This scenario is identical to the 2013-15 CIP with the exception of the Low Income propane to electric equivalent costs and savings, which are removed. These equivalents do not represent savings to the IPL system. Costs are escalated by the Consumer Price Index (CPI) each year, beginning in 2016. The measures from the 2013-2015 CIP are used as proxies for measures to be implemented in the future. While the actual measures may vary, the overall spending level and savings level are expected to be representative of the scenario. The Low Income and Direct Load Control projects are not varied by scenario, but are kept at the 2013-2015 level except for the annual inflation cost escalations, beginning in 2016. The Low Income Project is based on customer need and is not easily varied. The Direct Load Control Project was designed to meet its potential by 2015. Increases to the Project are not reasonable. Decreasing the Project in 2015 alone would yield a minimal difference with respect to Resource Planning. This is used as the basis for determining the other scenarios. It currently meets the minimum 1.5% savings requirements.
- High – Incentives increase 160 percent. Administrative costs increase 570% above the Base level. Participation doubles. All percentages are relative to the base scenario.
- Medium – Incentives increase 100 percent. Administrative costs increase 110%. Participation increases 30 percent. This scenario meets the minimum savings requirements.
- Low – Incentives are decreased 40 percent from the Base scenario. Administrative costs decrease 35 percent. Participation decreases 50 percent. This scenario has spending consistent with minimum spending required by current law. It does not meet the minimum savings requirements.

IPL modeled these various DSM levels as modifications to the demand and energy forecast, and each DSM scenario was run individually under the No Carbon and Minnesota Midpoint 2017 Carbon scenarios. Costs for the DSM plans were calculated outside of EGEAS, and subsequently added to EGEAS PVRR results as presented in Appendix 6G. One benefit of this type of "screening" approach is that each DSM scenario is "forced" into the model so that PVRR deltas can readily be compared. A second benefit of the screening approach is that the DSM scenario is the only change made per EGEAS run. Allowing DSM scenarios to be selected as part of expansion plans under sensitivity runs could potentially degrade understanding of results. For example, if a low natural gas cost sensitivity case selected a smaller DSM program – then what part of the PVRR delta is attributable to the gas cost change, and what part of the PVRR delta is attributable to the DSM program change?

EGEAS results indicate that IPL's existing levels of Minnesota DSM (Base scenario) provide the lowest PVRR (see Appendix 3G or 6H), and the expansion plans for the varied levels do not significantly change (see Appendix 6G).

6.6 Robustness of Proposed Plan

The proposed plan, as supported by the different scenarios, is very robust. The load and capability graph after resource additions resulting from the Reference Case (Proposed Plan) can be found in Appendix 6L. Diversity in fuels and technologies insulates against adverse movements in any one particular area which is advantageous when attempting to take a reasonable cost path while maintaining a balanced and reliable portfolio when meeting the needs of IPL's customers. With a diverse and balanced portfolio, IPL can be more flexible in the level of risk assumed in a period of time when there is significant uncertainty facing the electric utility industry.

The planned retirement of the intermediate and peaking units is not detrimental to adequate and reliable electric service, as opposed to a reactionary run to failure approach. IPL determined that an end of year 2016 retirement date was reasonable, for planning purposes, when coupled with the other components of the Resource Plan, which include the construction MGS in 2017, the DAEC PPA, as well as planned efficiency improvement and capacity and performance upgrade projects at the Lansing and Ottumwa Generating Stations.

Unplanned failures of generating units expose IPL customers to financial and service related risks such as replacement of generating capacity and the need to address potential grid reliability issues on short notice when units fail. The benefits of this proactive plan, as opposed to a reactive run to failure scenario, include:

- More predictable/less volatile costs for IPL customers;
- Adequate time to effectively and efficiently replace the generating capacity on behalf of IPL customers;
- Adequate time to work with MISO and ITC-M to address any potential grid reliability issues that could adversely impact customers;

- Adequate time to develop and execute an effective plan for shutdown and decommissioning of these units; and
- Adequate time to assist employees impacted by the retirement of a unit or entire plant.

6.7 Energy Balance

IPL's 2014 Resource Plan moves IPL toward a balanced generating fleet with increased fuel diversity and reduces IPL's reliance on market energy, as shown in the tables and figures below.

Table 6.7.1 – No Carbon Reference Case, Annual Energy Production by Fuel Type

Year	Coal	Market	Nuclear	Wind	Natural Gas
2014	49%	14%	20%	9%	8%
2015	44%	14%	20%	8%	13%
2016	44%	14%	20%	8%	13%
2017	44%	4%	19%	8%	24%
2018	46%	4%	19%	8%	22%
2019	39%	5%	19%	10%	27%
2020	39%	4%	19%	12%	26%
2021	35%	5%	19%	14%	28%
2022	35%	5%	19%	15%	27%
2023	34%	4%	18%	17%	25%
2024	34%	4%	18%	19%	25%
2025	32%	4%	18%	20%	25%
2026	32%	4%	18%	22%	24%
2027	31%	4%	18%	23%	24%
2028	31%	4%	18%	24%	24%
2029	30%	4%	18%	24%	24%

Table 6.7.2 – Minnesota Midpoint 2017 Carbon Reference Case, Annual Energy Production by Fuel Type

Year	Coal	Market	Nuclear	Wind	Natural Gas
2014	49%	14%	20%	9%	9%
2015	44%	14%	20%	8%	14%
2016	44%	14%	20%	8%	14%
2017	21%	5%	19%	8%	46%
2018	30%	4%	19%	10%	36%
2019	33%	5%	19%	12%	31%
2020	34%	5%	19%	14%	28%
2021	30%	5%	19%	16%	30%
2022	32%	5%	19%	17%	27%
2023	33%	4%	18%	19%	24%
2024	33%	4%	18%	20%	24%
2025	32%	4%	18%	22%	24%
2026	31%	4%	18%	24%	23%
2027	30%	3%	18%	25%	23%
2028	27%	3%	18%	26%	26%
2029	30%	3%	18%	24%	25%

Figure 6.7.1 – No Carbon Reference Case, Annual Energy Production by Fuel Type

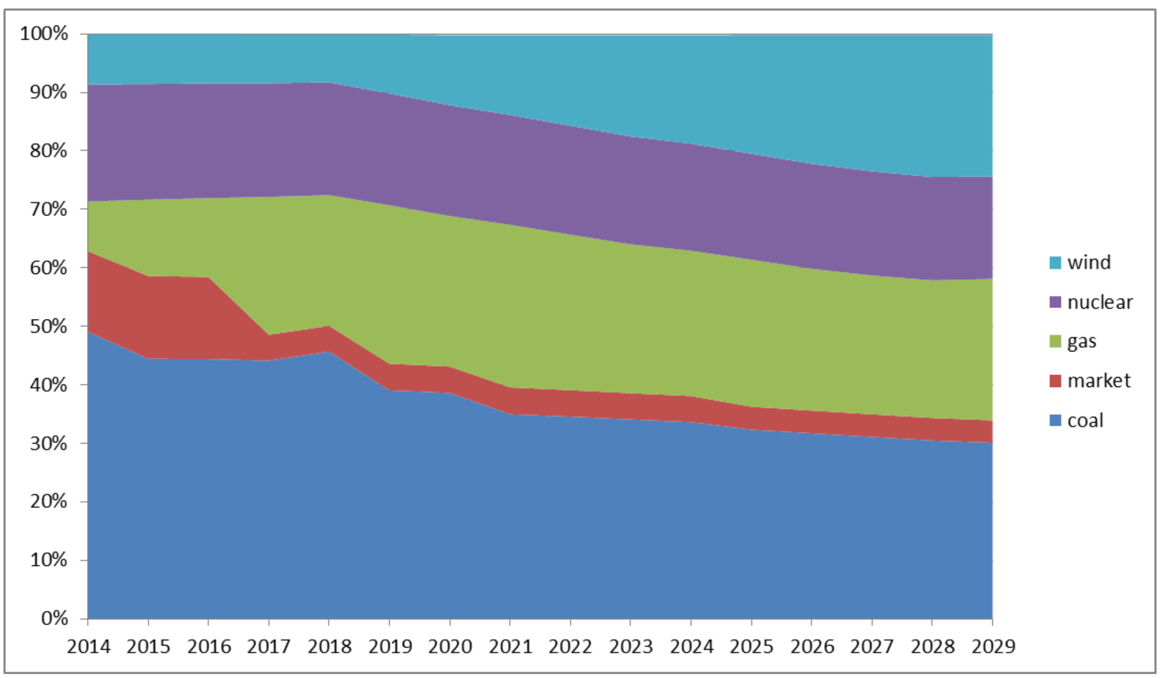
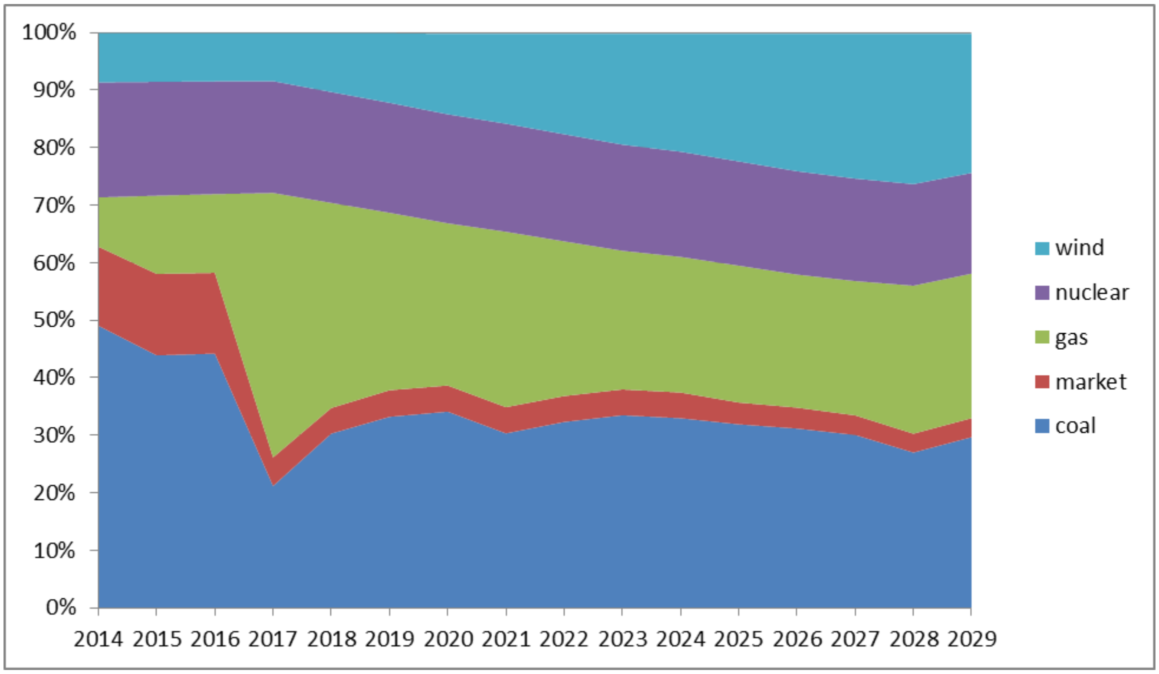


Figure 6.7.2 – Minnesota Midpoint 2017 Carbon Reference Case, Annual Energy Production by Fuel Type



6.8 Carbon Emissions

IPL's annual system CO_2 emissions and CO_2 emission rate for the No Carbon and Minnesota Midpoint Reference Cases are shown in the tables and figures below. IPL's CO_2 tons and emission rate (tons/MWh) both indicate a declining trend over the study period.

Table 6.8.1 – No Carbon Reference Case, CO_2 Emissions and Rate

Year	CO_2 Emissions, Tons	GWH Energy	Tons/ MWH
2014	12,743,326	16,928	0.753
2015	12,174,404	17,115	0.711
2016	12,337,128	17,274	0.714
2017	11,445,597	17,428	0.657
2018	11,742,116	17,585	0.668
2019	10,872,817	17,728	0.613
2020	10,768,150	17,884	0.602
2021	9,966,157	18,041	0.552
2022	9,871,790	18,200	0.542
2023	9,771,042	18,360	0.532
2024	9,713,352	18,522	0.524
2025	9,481,305	18,685	0.507
2026	9,354,061	18,850	0.496
2027	9,258,110	19,016	0.487
2028	9,185,949	19,184	0.479
2029	9,228,652	19,353	0.477

Table 6.8.2 – Minnesota Midpoint 2017 Carbon Reference Case, CO_2 Emissions and Rate

Year	CO_2 Emissions, Tons	GWH Energy	Tons/ MWH
2014	12,723,476	16,928	0.752
2015	12,050,156	17,115	0.704
2016	12,289,686	17,274	0.711
2017	8,303,354	17,428	0.476
2018	9,395,550	17,585	0.534
2019	9,647,823	17,728	0.544
2020	9,699,355	17,884	0.542
2021	9,215,612	18,041	0.511
2022	9,396,703	18,200	0.516
2023	9,490,080	18,360	0.517
2024	9,425,857	18,522	0.509
2025	9,254,765	18,685	0.495
2026	9,097,054	18,850	0.483
2027	8,923,417	19,016	0.469
2028	8,538,679	19,184	0.445
2029	9,114,819	19,353	0.471

Figure 6.8.1 – No Carbon Reference Case, CO_2 Emissions and Rate

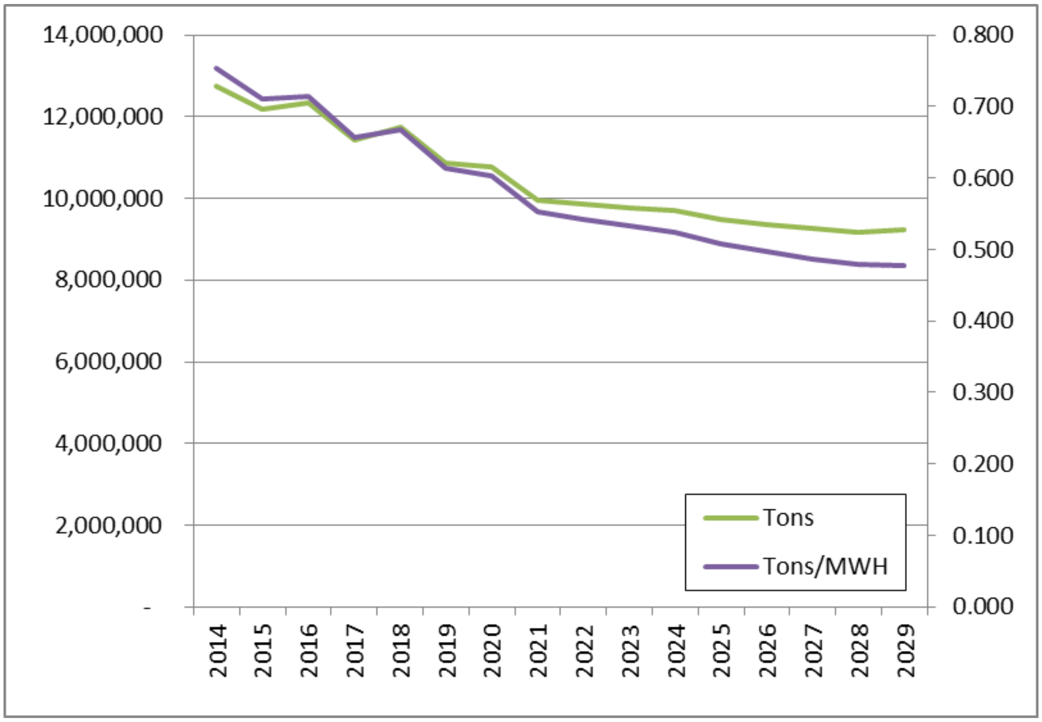
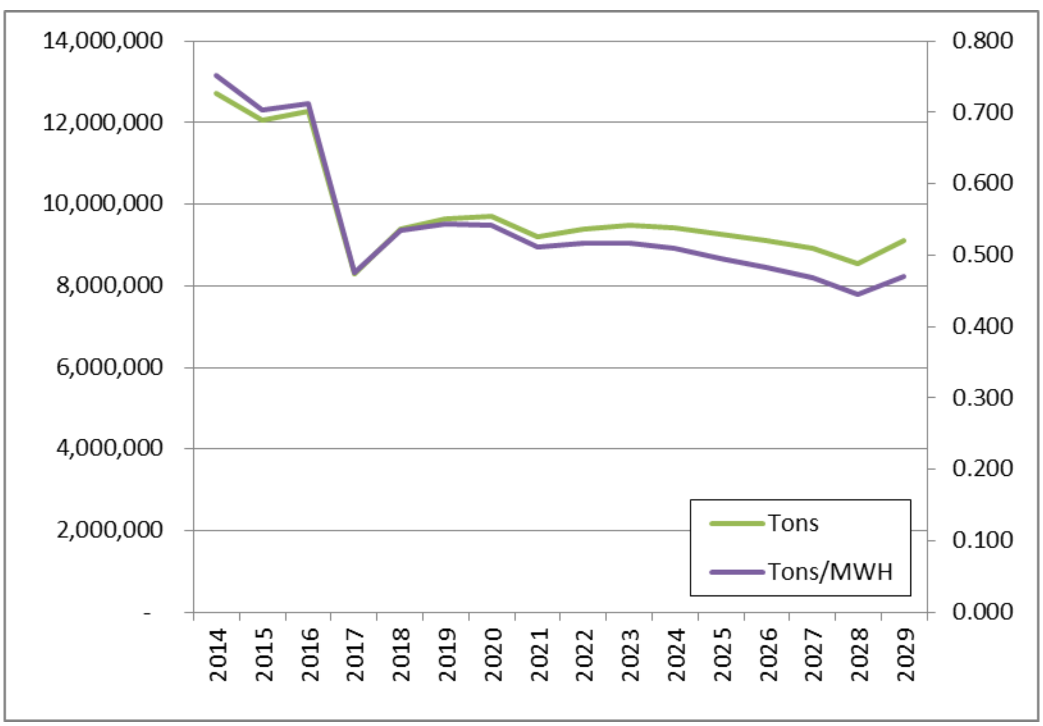


Figure 6.8.2 – Minnesota Midpoint 2017 Carbon Reference Case, CO_2 Emissions and Rate



6.9 Winter Peak Capacity and Firm Gas Needs

IPL periodically evaluates the reliability of its winter resource capabilities relative to firm winter peak. At this time there is not a formal, or separate, winter capacity requirement in MISO similar to Resource Adequacy requirements of Module E. However, IPL participates in the MISO Electric and Natural Gas Coordination Task Force (ENGCTF), where this issue is a topic of discussion. Such a winter peak review is illustrated for this Resource Plan. See Appendix 6M for detailed information.

IPL groups units by expected winter availability:

- Low - interruptible gas with lower reliability or retiring oil;
- TBD - Yet to Be Determined [TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]
- Wind - Wind units with ZRC's based on summer data (may be higher for winter but MISO has not provided winter values);
- Medium - Interruptible Gas but Historically Highly Reliable, Oil with historically good reliability, or future oil to gas conversions with expected good winter availability or potential firm gas; and
- High - coal, nuclear, oil, firm gas.

The analysis presented is conservative for several reasons:

- ZRCs/UCAP values are used instead of higher ICAP values;
- ZRCs are set by summer ratings, because winter ratings may be higher, especially for gas units and potentially wind units.
- No coincidence factor for MISO winter peak applied;
- Future resource additions other than Marshalltown Generating Station not considered; and
- IPL can further pursue firming up gas delivery to several units in the "Medium" and "TBD" groups.

IPL currently has adequate winter capacity to reliably cover firm winter peak with the resource groupings of “High” and “Medium” for the next several years. Additionally, there is flexibility to pursue obtaining firm gas on additional units if needed. IPL will continue to monitor and participate in the MISO ENGCTF.

6.10 Long Term Heat Rate and Availability

The 2014 Resource Plan analysis does not include annual degradation of heat rate or availability due to age for any units, whether coal-fired, natural gas-fired, nuclear, or renewable. In both the 2010 Resource Plan and 2012 Baseload Diversification Study, IPL included costs for ongoing capital and fixed Operations & Maintenance (O&M) investments to maintain plant performance. This differs from previous IRPs, which only included a variable O&M component. The 2014 Resource Plan continues the 2010 and 2012 approach, and the ongoing investments are shown in Appendix 6D.

[TRADE SECRET DATA BEGINS

The 2014 Resource Plan assumes that

TRADE SECRET DATA ENDS]

6.10.1 Fleet Health Capital Investments

Fleet Health capital investments include projects such as piping inspections, large valve replacements, major turbine and pump overhauls, boiler section replacements and large component replacements. In order to maintain reliability and effective long term heat rates, fleet health capital dollars are designated to maintain the unit's operational efficiency and support availability. [TRADE SECRET DATA BEGINS At TRADE SECRET DATA ENDS] the plant fleet health dollars allow for a new air compressor, enhanced air heater baskets, and electrostatic precipitator enhancements. [TRADE SECRET DATA BEGINS Similarly, at TRADE SECRET DATA ENDS] additional precipitator Transformer-Rectifier sets, new boiler sections and new air heater baskets allow for continued, efficient operations as well as environmental compliance. These projects are intended to, not only make the plant run more reliably and efficiently, but to enhance performance, lower emissions rates, and contribute to the viability of the plants. At Kapp, investments will be made in 2014 to convert the unit to gas as well as reduce boiler tube failures. Combined with work done at Kapp in 2013, which included rebuilding the circulating water pumps and repairing the final superheat and reheat pendants, the unit will operate reliably for several more years while controlling overall costs for customers.

Much like routine maintenance on any piece of machinery, constantly monitoring, maintaining, and replacing wear items like conveyors, mills, motors, and piping systems, allows the plant to be ready to serve and avoids costly and potentially dangerous failures that can impact fuel costs and require expensive, last minute replacement power. Because power production is a capital intensive endeavor, IPL has constantly invested capital and O&M dollars to maintain the power plant assets and long term plant performance.

6.10.2 Major Emissions Control Investments

Recently, the fleet health projects have been planned in concert with major investments in emissions control equipment. Several of the Tier 2 plants have found low cost, alternative means to comply with stricter air compliance regulations. Improved particulate matter emissions control has been achieved by capital investments to the electrostatic precipitators, and the installation of ACI systems will lower mercury emissions. In order to make these improvements work sufficiently to meet MATS compliance, the boilers must fire efficiently. Therefore, these improvements have been planned concurrently with the boiler improvements mentioned above. The new air heater baskets lower overall exit gas temperatures allowing the carbon injection chemicals to work more effectively and the result is lower fuels costs and reduced Hg emissions. To assure that systems are running properly, they must be constantly monitored and periodically inspected, thus the installation and maintenance of Continuous Emission Monitors (CEMs) are included in the projected budgets. Maintenance and replacement of essential components are critical to maintaining heat rate and thermal efficiency and ensuring compliance with environmental requirements.

6.10.3 Major Boiler Capital and Boiler O&M

Similar to the emissions control equipment program, the boilers must be monitored to maintain appropriate heat transfer capabilities. Sootblowing is more important than ever to maximize heat transfer by keeping tubes clean, but this practice has the consequence of diminished wall thickness. Over time, sootblowing and continued operation with thinning and/or eroded tubes threatens the availability of the unit. To address this concern, boiler sections are monitored to determine when major capital repairs and/or replacements are necessary to assure the unit's sustained ability to meet full load capacity and maintain optimal heat rates.

6.10.4 Operations and Maintenance Investments

Much like with capital projects, fleet health, and boiler/unit O&M funds, the annual costs of smaller scope projects that maintain the units' heat rates, safety rating and reliability figures. Fleet Health Fixed O&M projects can vary from year to year, but include projects such as boiler tube failure reduction, replacement of wear parts and precipitator maintenance, all of which help maintain plant performance, lower fuel costs and improve environmental compliance. For the funds allocated, plant management works with the engineering and construction groups to select high value projects based on the unique operating parameters and challenges at each plant. Given the importance and criticality of the boilers, turbines and high energy piping, plus the added need to comply with stricter environmental regulations, additional maintenance funds are allocated for those plan components which the plant personnel, again, decide the best course of action. Opportunities to learn from other locations, share common components and avert similar negative outcomes by best practice sharing sessions foster continual improvement which maximizes efficiency and availability.

Note that these projects outlined above are outside the "Base" Fixed O&M shown in Appendix 6D. The Base Fixed O&M covers labor, administrative and typical ongoing operating costs.

6.11 Drought And High Water Temperature Risks

IPL has multiple plants on the Mississippi River (Burlington, Kapp, Dubuque and Lansing). These plants have always had adequate cooling water flow, even at low Mississippi flow conditions. De-rates of the units may be needed to protect the turbines or meet environmental discharge temperature limitations at high inlet temperature conditions. When inlet temperature reach 85 degrees Fahrenheit the potential for de-rating the unit exists if the condensers are not optimally clean and turbine backpressure reach levels near maximum allowable.

Fox Lake Generating Station uses cooling water from Fox Lake. Although the lake level can drop substantial during drought conditions there has never been a problem with cooling water supply. Fox Lake may have to de-rate the unit to protect the turbine or meet environmental discharge temperature limits at high inlet temperature conditions.

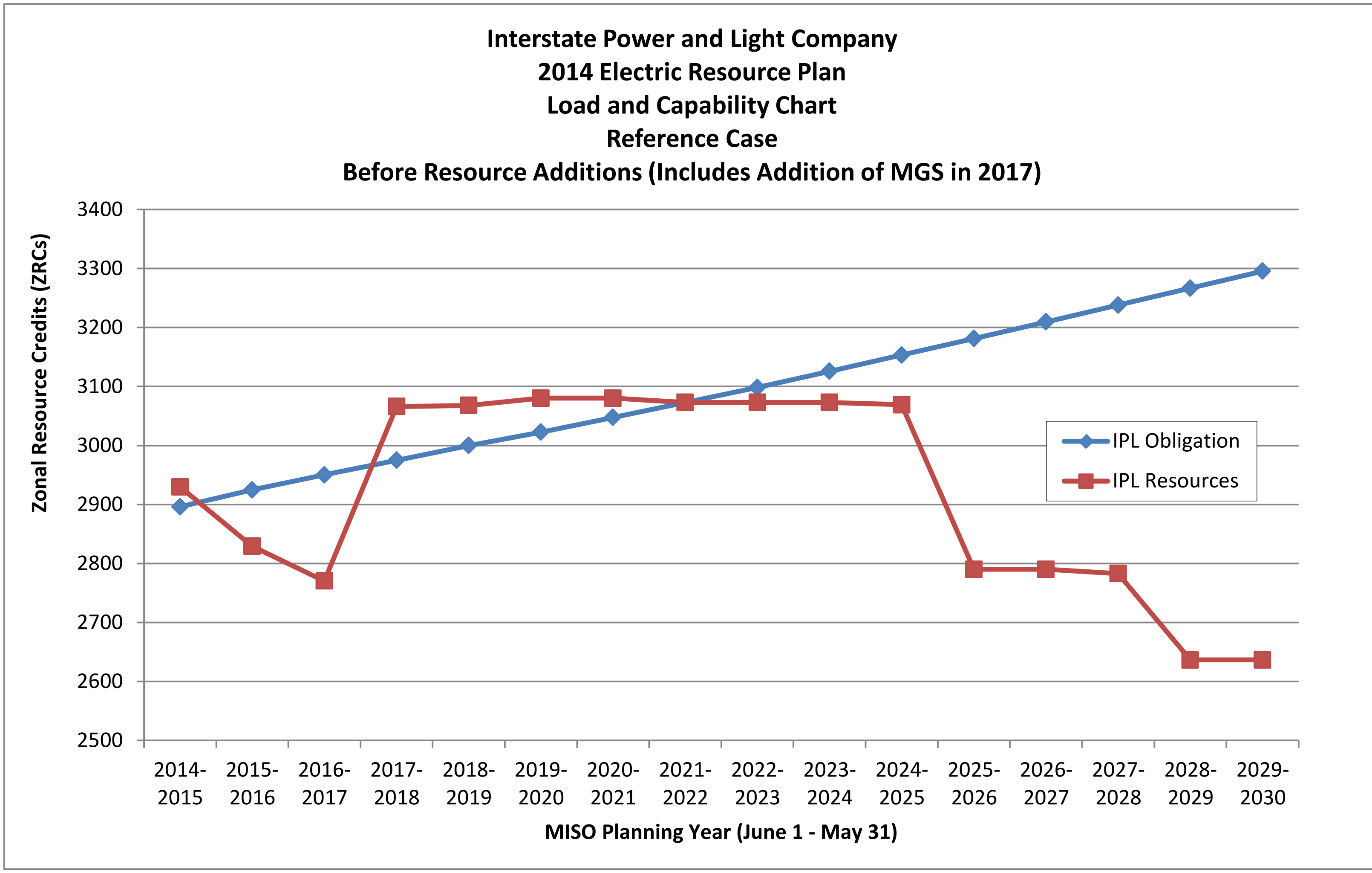
The Emery Generating Station and Sutherland Generating Station both use well water for cooling water and have cooling towers. At Sutherland, the cooling water supply can be supplemented with city water. These plants have never had issues during drought conditions with water supply or high temperatures.

Prairie Creek Generating Station takes cooling water from the Cedar River. The construction of the roller dam downstream of the plant was designed to maintain net positive suction head for circulating water pumps on units 1-4 and help minimize any low water flow conditions.

The Ottumwa Generation Station has developed a contingency plan that takes effect when the Des Moines River level drops to 3 feet at the site. The plant would take various steps to keep the unit on line including de-rating the unit but the unit would come off line if the level drops to 2 feet at the site. In the summer with extremely high ambient temperatures, the circulating water temperature from the cooling tower can get upwards of 95 degrees Fahrenheit and Ottumwa can be de-rated if the condenser is not at optimal cleanliness. In 2013 with the new ball cleaning system in place on the condenser, Ottumwa was not de-rated by high temperatures at all.

IPL is well positioned to react to potential drought and high water temperature risks. Historical performance has been good, and when problems have occurred IPL has taken corrective measures (such as at Ottumwa). Potential de-rate conditions do not subsist for days, and de-rate reductions are generally not a large portion of a plant, let alone IPL's fleet. IPL's participation in MISO moderates risk from a collective operations stance. Further, IPL's portfolio is moving to a more balanced fuel supply which further moderates risk.

IPL's sensitivity analysis in this Resource Plan covers a wide range of potential evolving conditions. The impacts of severe, long lasting drought and high water temperature conditions would be similar to a high load forecast scenario where additional generation would be needed over the base load forecast. IPL's high load forecast requires an additional 282.7 ZRCs over the base load forecast. This modeling sensitivity appears to cover severe capacity shortfalls, well and above the drought and high water temperature conditions seen historically.


Interstate Power and Light Company
2014 Electric Resource Plan
Load and Capability Chart
Reference Case
Before Resource Additions (Includes Addition of MGS in 2017)
Zonal Resource Credits (ZRCs)
3400
3300
3200
3100
3000
2900
2800
2700
2600
2500
2014-2015
2015-2016
2016-2017
2017-2018
2018-2019
2019-2020
2020-2021
2021-2022
2022-2023
2023-2024
2024-2025
2025-2026
2026-2027
2027-2028
2028-2029
2029-2030
MISO Planning Year (June 1 - May 31)
IPL Obligation
IPL Resources

[TRADE SECRET DATA BEGINS

Section 6
Appendix 6B
4 Pages

Fuel and Capacity Costs

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

[TRADE SECRET DATA BEGINS

Section 6
Appendix 6C
1 Page

IPL’s Existing Generating Units, Purchases and Sales

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

[TRADE SECRET DATA BEGINS

Section 6
Appendix 6D
10 Pages

Projected Costs and Operating Parameters of Tier 1 and Tier 2 Units

TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS

Section 6
Appendix 6E
3 Pages

Intermediate Steam Unit Repair Costs

TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS

Section 6
Appendix 6F
1 Page

Peaking Unit Repair Costs

TRADE SECRET DATA ENDS]

IPL 2014 IRP

Scenario: No Carbon
Case: a001 Base Assumptions (Reference Case)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a002 High Load Forecast

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	150	0	0	0	0	0	0	0	0	0	0
2016	250	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	50	0	0	0	0	0	0	100	10	0	0
2021	50	0	0	0	0	0	0	100	0	0	0
2022	100	0	0	0	0	0	0	100	0	0	0
2023	150	0	0	0	0	0	0	100	0	0	0
2024	150	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	191.7	0	0	0	0	100	0	0	0
2029	50	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	950	0	191.7	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a003 Low Load Forecast

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	150	0	0	0	0	0	0	100	0	0	0
2026	150	0	0	0	0	0	0	100	0	0	0
2027	150	0	0	0	0	0	0	100	0	0	0
2028	100	0	191.7	0	0	0	0	100	0	0	0
2029	100	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	950	0	191.7	0	0	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a004 No Economy Energy

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	0	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a005 Natural Gas Prices +10% (and On Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a006 Natural Gas Prices +20% (and On Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a007 Natural Gas Prices +30% (and On Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a008 Natural Gas Prices -10% (and On Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1000	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a009 Natural Gas Prices -20% (and On Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	10	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	50	0	0	0	0	0	0	0	0	0	0
2024	50	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	400	0	0	0	604.701	0	0	700	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a010 Natural Gas Prices -30% (and On Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	10	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	0	0	0	0
2024	100	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	500	0	0	0	604.701	0	0	600	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a011 Coal Prices +10% (and Off Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon

Case: a012 Coal Prices +20% (and Off Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a013 Coal Prices +30% (and Off Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a014 Coal Prices -10% (and Off Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a015 Coal Prices -20% (and Off Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a016 Coal Prices -30% (and Off Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a017 New Unit Capital Costs +10%

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	150	0	191.7	0	0	0	0	100	0	0	0
2026	150	0	0	0	0	0	0	100	0	0	0
2027	150	0	0	0	0	0	0	100	0	0	0
2028	50	0	0	299.8	0	0	0	100	0	0	0
2029	50	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	850	0	191.7	299.8	0	0	0	1000	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a018 New Unit Capital Costs -10%

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a019 Higher Wind Prices, +$20/MWH

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	10	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	0	0	0	0
2024	100	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	604.701	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0
2028	50	0	0	0	0	0	0	0	0	0	0
2029	100	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	650	0	0	0	604.701	0	0	0	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a020 Higher Wind Prices, +$10/MWH

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	10	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	50	0	0	0	0	0	0	0	0	0	0
2024	50	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	400	0	0	0	604.701	0	0	600	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a021 Lower Wind Prices, -$10/MWH

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	100	0	191.7	0	0	0	0	100	0	0	0
2026	100	0	0	0	0	0	0	100	0	0	0
2027	150	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	299.8	0	0	0	100	0	0	0
2029	50	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	700	0	191.7	299.8	0	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a022 Lower Wind Prices, -$20/MWH

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	100	0	191.7	0	0	0	0	100	0	0	0
2026	100	0	0	0	0	0	0	100	0	0	0
2027	150	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	299.8	0	0	0	100	0	0	0
2029	50	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	700	0	191.7	299.8	0	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a033 Base MN DSM

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a034 High MN DSM

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	100	0	191.7	0	0	0	0	100	0	0	0
2026	100	0	0	0	0	0	0	100	0	0	0
2027	150	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	299.8	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	650	0	191.7	299.8	0	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a035 Medium MN DSM

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	100	0	191.7	0	0	0	0	100	0	0	0
2026	150	0	0	0	0	0	0	100	0	0	0
2027	150	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	299.8	0	0	0	100	0	0	0
2029	50	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	750	0	191.7	299.8	0	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a036 Low MN DSM

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b001 Base Assumptions (Reference Case)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b002 High Load Forecast

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	150	0	0	0	0	0	0	0	0	0	0
2016	250	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	50	0	0	0	0	0	0	100	10	0	0
2021	50	0	0	0	0	0	0	100	0	0	0
2022	100	0	0	0	0	0	0	100	0	0	0
2023	150	0	0	0	0	0	0	100	0	0	0
2024	150	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	191.7	0	0	0	0	100	0	0	0
2029	50	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	950	0	191.7	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b003 Low Load Forecast

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	100	0	0	0	0	0	0	100	0	0	0
2026	100	0	0	0	0	0	0	100	0	0	0
2027	100	0	0	0	0	0	0	100	0	0	0
2028	100	0	191.7	0	0	0	0	100	0	0	0
2029	100	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	800	0	191.7	0	0	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b004 No Economy Energy

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b005 Natural Gas Prices +10% (and On Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	100	0	191.7	0	0	0	0	100	0	0	0
2026	100	0	0	0	0	0	0	100	0	0	0
2027	150	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	299.8	0	0	0	100	0	0	0
2029	50	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	700	0	191.7	299.8	0	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b006 Natural Gas Prices +20% (and On Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b007 Natural Gas Prices +30% (and On Peak Market Energy)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b008 Natural Gas Prices -10% (and On Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon

Case: b009 Natural Gas Prices -20% (and On Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b010 Natural Gas Prices -30% (and On Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b011 Coal Prices +10% (and Off Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b012 Coal Prices +20% (and Off Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b013 Coal Prices +30% (and Off Peak Market Energy)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b014 Coal Prices -10% (and Off Peak Market Energy)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b015 Coal Prices -20% (and Off Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	100	0	191.7	0	0	0	0	100	0	0	0
2026	100	0	0	0	0	0	0	100	0	0	0
2027	150	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	299.8	0	0	0	100	0	0	0
2029	50	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	700	0	191.7	299.8	0	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b016 Coal Prices -30% (and Off Peak Market Energy)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	100	0	191.7	0	0	0	0	100	0	0	0
2026	100	0	0	0	0	0	0	100	0	0	0
2027	150	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	299.8	0	0	0	100	0	0	0
2029	50	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	700	0	191.7	299.8	0	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b017 New Unit Capital Costs +10%

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b018 New Unit Capital Costs -10%

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b019 Higher Wind Prices, +$20/MWH

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	10	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	50	0	0	0	0	0	0	0	0	0	0
2023	50	0	0	0	0	0	0	0	0	0	0
2024	100	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	500	0	0	0	604.701	0	0	600	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b020 Higher Wind Prices, +$10/MWH

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b021 Lower Wind Prices, -$10/MWH

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b022 Lower Wind Prices, -$20/MWH

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

Scenario: Minnesota Midpoint 2017 Carbon
Case: c001 Base Assumptions (Reference Case)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c002 High Load Forecast

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	150	0	0	0	0	0	0	0	0	0	0
2016	250	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	50	0	0	0	0	0	0	100	10	0	0
2021	50	0	0	0	0	0	0	100	0	0	0
2022	100	0	0	0	0	0	0	100	0	0	0
2023	150	0	0	0	0	0	0	100	0	0	0
2024	150	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	191.7	0	0	0	0	100	0	0	0
2029	50	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	950	0	191.7	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c003 Low Load Forecast

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	100	0	0	0	0	0	0	100	0	0	0
2026	100	0	0	0	0	0	0	100	0	0	0
2027	100	0	0	0	0	0	0	100	0	0	0
2028	100	0	191.7	0	0	0	0	100	0	0	0
2029	100	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	800	0	191.7	0	0	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c004 No Economy Energy

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c005 Natural Gas Prices +10% (and On Peak Market Energy)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c006 Natural Gas Prices +20% (and On Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c007 Natural Gas Prices +30% (and On Peak Market Energy)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c008 Natural Gas Prices -10% (and On Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c009 Natural Gas Prices -20% (and On Peak Market Energy)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c010 Natural Gas Prices -30% (and On Peak Market Energy)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	0	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c011 Coal Prices +10% (and Off Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c012 Coal Prices +20% (and Off Peak Market Energy)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c013 Coal Prices +30% (and Off Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

Scenario: Minnesota Midpoint 2017 Carbon
Case: c014 Coal Prices -10% (and Off Peak Market Energy)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	100	0	191.7	0	0	0	0	100	0	0	0
2026	100	0	0	0	0	0	0	100	0	0	0
2027	150	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	299.8	0	0	0	100	0	0	0
2029	50	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	700	0	191.7	299.8	0	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c015 Coal Prices -20% (and Off Peak Market Energy)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	100	0	191.7	0	0	0	0	100	0	0	0
2026	100	0	0	0	0	0	0	100	0	0	0
2027	150	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	299.8	0	0	0	100	0	0	0
2029	50	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	700	0	191.7	299.8	0	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c016 Coal Prices -30% (and Off Peak Market Energy)

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	100	0	191.7	0	0	0	0	100	0	0	0
2026	100	0	0	0	0	0	0	100	0	0	0
2027	150	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	299.8	0	0	0	100	0	0	0
2029	50	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	700	0	191.7	299.8	0	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c017 New Unit Capital Costs +10%

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	100	0	191.7	0	0	0	0	100	0	0	0
2026	100	0	0	0	0	0	0	100	0	0	0
2027	150	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	299.8	0	0	0	100	0	0	0
2029	50	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	700	0	191.7	299.8	0	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c018 New Unit Capital Costs -10%

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c019 Higher Wind Prices, +$20/MWH

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	10	0	0
2021	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	50	0	0	0	0	0	0	0	0	0	0
2024	50	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	400	0	0	0	604.701	0	0	600	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c020 Higher Wind Prices, +$10/MWH

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c021 Lower Wind Prices, -$10/MWH

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c022 Lower Wind Prices, -$20/MWH

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c023 CO2 Scenario - Minnesota High

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c024 CO2 Scenario - Minnesota Low

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c025 Externalities High

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c026 Externalities Low

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c027 50% DSM and Renewables

	1 yr pk pwr purch	CT-192	wind	solar	biomass LFG	MGS
YEAR	1	3	8	9	10	11
----	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0
2015	100	0	0	0	0	0
2016	200	0	0	0	0	0
2017	0	0	0	0	0	647.599
2018	0	0	100	0	0	0
2019	0	0	100	0	0	0
2020	0	0	100	0	0	0
2021	0	0	100	0	0	0
2022	0	0	100	0	0	0
2023	0	0	100	0	0	0
2024	0	0	100	0	0	0
2025	100	191.7	100	0	0	0
2026	100	0	100	0	0	0
2027	100	0	100	100	0	0
2028	100	0	100	100	100	0
2029	100	0	0	100	0	0
----	--------	--------	--------	--------	--------	--------
TOTAL	800	191.7	1100	300	100	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c028 75% DSM and Renewables

	1 yr pk pwr purch	CT-192	wind	solar	biomass LFG	MGS
YEAR	1	3	8	9	10	11
----	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0
2015	100	0	0	0	0	0
2016	200	0	0	0	0	0
2017	0	0	0	0	0	647.599
2018	0	0	100	0	0	0
2019	0	0	100	0	0	0
2020	0	0	100	0	0	0
2021	0	0	100	0	0	0
2022	0	0	100	0	0	0
2023	0	0	100	0	0	0
2024	0	0	100	100	0	0
2025	100	0	100	100	100	0
2026	50	0	100	100	0	0
2027	50	0	100	100	0	0
2028	150	0	100	100	0	0
2029	150	0	0	100	0	0
----	--------	--------	--------	--------	--------	--------
TOTAL	800	0	1100	600	100	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c029 SO2 allowance cost $1,000/ton

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c030 SO2 allowance cost $2,000/ton

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c031 No Forced Solar

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	0	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	0	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c032 No Recent RES additions

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c033 Base MN DSM

YEAR	1 yr pk pwr purch 1	CT-88 2	CT-192 3	cc-300 4	cc-605 5	PC w/CC 6	PC 7	wind 8	solar 9	nuclear 10	MGS 11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c034 High MN DSM

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	100	0	191.7	0	0	0	0	100	0	0	0
2026	100	0	0	0	0	0	0	100	0	0	0
2027	100	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	299.8	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	600	0	191.7	299.8	0	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c035 Medium MN DSM

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c036 Low MN DSM

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

EGEAS Present Value Revenue Requirements ($M 2013$)

2014 IRP

		"a" series	"b" series	"c" series	delta vs case 001 "a" series	delta vs case 001 "b" series	delta vs case 001 "c" series
EGEAS Case #	Case Description	No Carbon	Wood Mackenzie 2023 Carbon	Minnesota Midpoint 2017 Carbon (and Midpoint Externalities)	No Carbon	Wood Mackenzie 2023 Carbon	Minnesota Midpoint 2017 Carbon (and Midpoint Externalities)
_001	Base Assumptions (Reference Case)	15,220.0	16,883.8	17,636.7	-	-	-
_002	High Load Forecast	16,193.5	18,009.6	18,764.8	973.5	1,125.8	1,128.1
_003	Low Load Forecast	14,274.1	15,797.5	16,532.7	(945.9)	(1,086.3)	(1,103.9)
_004	No Economy Energy	15,780.8	17,414.9	18,169.3	560.7	531.1	532.7
_005	Natural Gas Prices +10% (and On Peak Market Energy)	15,512.2	17,258.4	17,980.5	292.1	374.6	343.9
_006	Natural Gas Prices +20% (and On Peak Market Energy)	15,797.1	17,560.9	18,286.5	577.1	677.1	649.8
_007	Natural Gas Prices +30% (and On Peak Market Energy)	16,079.0	17,847.8	18,589.3	859.0	964.0	952.6
_008	Natural Gas Prices -10% (and On Peak Market Energy)	14,903.8	16,437.4	17,179.7	(316.2)	(446.4)	(457.0)
_009	Natural Gas Prices -20% (and On Peak Market Energy)	14,490.7	15,934.9	16,613.2	(729.3)	(948.9)	(1,023.5)
_010	Natural Gas Prices -30% (and On Peak Market Energy)	13,944.4	15,372.4	15,977.1	(1,275.6)	(1,511.4)	(1,659.6)
_011	Coal Prices +10% (and Off Peak Market Energy)	15,558.1	17,111.3	17,863.3	338.1	227.5	226.7
_012	Coal Prices +20% (and Off Peak Market Energy)	15,846.9	17,308.1	18,035.6	626.9	424.3	399.0
_013	Coal Prices +30% (and Off Peak Market Energy)	16,083.9	17,480.9	18,174.4	863.8	597.1	537.8
_014	Coal Prices -10% (and Off Peak Market Energy)	14,860.4	16,616.0	17,345.3	(359.6)	(267.8)	(291.4)
_015	Coal Prices -20% (and Off Peak Market Energy)	14,497.8	16,306.0	17,016.8	(722.2)	(577.8)	(619.9)
_016	Coal Prices -30% (and Off Peak Market Energy)	14,135.2	15,968.5	16,684.4	(1,084.8)	(915.3)	(952.2)
_017	New Unit Capital Costs +10%	15,572.4	17,250.5	18,002.9	352.4	366.7	366.2
_018	New Unit Capital Costs -10%	14,852.3	16,504.9	17,257.8	(367.7)	(378.9)	(378.9)
_019	Higher Wind Prices, +$20/MWH	15,595.5	17,569.6	18,346.6	375.5	685.8	710.0
_020	Higher Wind Prices, +$10/MWH	15,519.8	17,282.9	18,051.9	299.8	399.1	415.3
_021	Lower Wind Prices, -$10/MWH	14,806.9	16,461.2	17,214.1	(413.1)	(422.6)	(422.6)
_022	Lower Wind Prices, -$20/MWH	14,384.3	16,038.6	16,791.5	(835.7)	(845.2)	(845.2)
_023	CO2 Scenario - Minnesota High			18,726.8			1,090.2
_024	CO2 Scenario - Minnesota Low			16,174.5			(1,462.1)
_025	Externalities High			17,643.5			6.8
_026	Externalities Low			17,630.2			(6.5)
_027	50% DSM and Renewables			17,906.4			269.7
_028	75% DSM and Renewables			18,197.9			561.3
_029	SO2 allowance cost $1,000/ton			17,707.3			70.6
_030	SO2 allowance cost $2,000/ton			17,772.5			135.8
_031	No Forced Solar			17,619.6			(17.0)
_032	No Recent RES additions			17,732.7			96.0

MSN DSM Analysis (DSM costs added outside of EGEAS)

		"a" series	"b" series	"c" series	delta vs case c031 "a" series	delta vs case c031 "b" series	delta vs case c031 "c" series
EGEAS Case #	Case Description	No Carbon	Wood Mackenzie 2023 Carbon	Minnesota Midpoint 2017 Carbon (and Midpoint Externalities)	No Carbon	Wood Mackenzie 2023 Carbon	Minnesota Midpoint 2017 Carbon (and Midpoint Externalities)
_033	Base MN DSM	15,265.1		17,681.8	-		-
_034	High MN DSM	15,296.0		17,695.8	30.9		14.1
_035	Medium MN DSM	15,288.0		17,700.0	22.9		18.2
_036	Low MN DSM	15,284.9		17,710.4	19.8		28.6

Total Additions 2014-2029
"a" series, No Carbon

				c25	d25	e25	f25	g25	h25	i25	j25	k25	l25	m25
Case	Description	PVRR, $M	PVRR delta from _001	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
a001	Base Assumptions (Reference Case)	15,220.0	-	300	0	0	0	604.701	0	0	1100	10	0	647.599
a002	High Load Forecast	16,193.5	973.5	950	0	191.7	0	604.701	0	0	1100	10	0	647.599
a003	Low Load Forecast	14,274.1	(945.9)	950	0	191.7	0	0	0	0	1100	10	0	647.599
a004	No Economy Energy	15,780.8	560.7	300	0	0	0	604.701	0	0	1100	10	0	647.599
a005	Natural Gas Prices +10% (and On Peak Market Energy)	15,512.2	292.1	300	0	0	0	604.701	0	0	1100	10	0	647.599
a006	Natural Gas Prices +20% (and On Peak Market Energy)	15,797.1	577.1	300	0	0	0	604.701	0	0	1100	10	0	647.599
a007	Natural Gas Prices +30% (and On Peak Market Energy)	16,079.0	859.0	300	0	0	0	604.701	0	0	1100	10	0	647.599
a008	Natural Gas Prices -10% (and On Peak Market Energy)	14,903.8	(316.2)	300	0	0	0	604.701	0	0	1000	10	0	647.599
a009	Natural Gas Prices -20% (and On Peak Market Energy)	14,490.7	(729.3)	400	0	0	0	604.701	0	0	700	10	0	647.599
a010	Natural Gas Prices -30% (and On Peak Market Energy)	13,944.4	(1,275.6)	500	0	0	0	604.701	0	0	600	10	0	647.599
a011	Coal Prices +10% (and Off Peak Market Energy)	15,558.1	338.1	300	0	0	0	604.701	0	0	1100	10	0	647.599
a012	Coal Prices +20% (and Off Peak Market Energy)	15,846.9	626.9	300	0	0	0	604.701	0	0	1100	10	0	647.599
a013	Coal Prices +30% (and Off Peak Market Energy)	16,083.9	863.8	300	0	0	0	604.701	0	0	1100	10	0	647.599
a014	Coal Prices -10% (and Off Peak Market Energy)	14,860.4	(359.6)	300	0	0	0	604.701	0	0	1100	10	0	647.599
a015	Coal Prices -20% (and Off Peak Market Energy)	14,497.8	(722.2)	300	0	0	0	604.701	0	0	1100	10	0	647.599
a016	Coal Prices -30% (and Off Peak Market Energy)	14,135.2	(1,084.8)	300	0	0	0	604.701	0	0	1100	10	0	647.599
a017	New Unit Capital Costs +10%	15,572.4	352.4	850	0	191.7	299.8	0	0	0	1000	10	0	647.599
a018	New Unit Capital Costs -10%	14,852.3	(367.7)	300	0	0	0	604.701	0	0	1100	10	0	647.599
a019	Higher Wind Prices, +$20/MWH	15,595.5	375.5	650	0	0	0	604.701	0	0	0	10	0	647.599
a020	Higher Wind Prices, +$10/MWH	15,519.8	299.8	400	0	0	0	604.701	0	0	600	10	0	647.599
a021	Lower Wind Prices, -$10/MWH	14,806.9	(413.1)	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
a022	Lower Wind Prices, -$20/MWH	14,384.3	(835.7)	700	0	191.7	299.8	0	0	0	1100	10	0	647.599

MSN DSM Analysis (DSM costs added outside of EGEAS)
"a" series, No Carbon

				c25	d25	e25	f25	g25	h25	i25	j25	k25	l25	m25
Case	Description	PVRR, $M	PVRR delta from c033	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
a033	Base MN DSM	15,265.1	-	300	0	0	0	604.701	0	0	1100	10	0	647.599
a034	High MN DSM	15,296.0	30.9	650	0	191.7	299.8	0	0	0	1100	10	0	647.599
a035	Medium MN DSM	15,288.0	22.9	750	0	191.7	299.8	0	0	0	1100	10	0	647.599
a036	Low MN DSM	15,284.9	19.8	300	0	0	0	604.701	0	0	1100	10	0	647.599

Total Additions 2014-2029
"b" series, Wood Mackenzie 2023 Carbon

Case	Description	PVRR, $M	PVRR delta from _001	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
				c25	d25	e25	f25	g25	h25	i25	j25	k25	l25	m25
b001	Base Assumptions (Reference Case)	16,883.8	-	300	0	0	0	604.701	0	0	1100	10	0	647.599
b002	High Load Forecast	18,009.6	1,125.8	950	0	191.7	0	604.701	0	0	1100	10	0	647.599
b003	Low Load Forecast	15,797.5	(1,086.3)	800	0	191.7	0	0	0	0	1100	10	0	647.599
b004	No Economy Energy	17,414.9	531.1	300	0	0	0	604.701	0	0	1100	10	0	647.599
b005	Natural Gas Prices +10% (and On Peak Market Energy)	17,258.4	374.6	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
b006	Natural Gas Prices +20% (and On Peak Market Energy)	17,560.9	677.1	300	0	0	0	604.701	0	0	1100	10	0	647.599
b007	Natural Gas Prices +30% (and On Peak Market Energy)	17,847.8	964.0	300	0	0	0	604.701	0	0	1100	10	0	647.599
b008	Natural Gas Prices -10% (and On Peak Market Energy)	16,437.4	(446.4)	300	0	0	0	604.701	0	0	1100	10	0	647.599
b009	Natural Gas Prices -20% (and On Peak Market Energy)	15,934.9	(948.9)	300	0	0	0	604.701	0	0	1100	10	0	647.599
b010	Natural Gas Prices -30% (and On Peak Market Energy)	15,372.4	(1,511.4)	300	0	0	0	604.701	0	0	1100	10	0	647.599
b011	Coal Prices +10% (and Off Peak Market Energy)	17,111.3	227.5	300	0	0	0	604.701	0	0	1100	10	0	647.599
b012	Coal Prices +20% (and Off Peak Market Energy)	17,308.1	424.3	300	0	0	0	604.701	0	0	1100	10	0	647.599
b013	Coal Prices +30% (and Off Peak Market Energy)	17,480.9	597.1	300	0	0	0	604.701	0	0	1100	10	0	647.599
b014	Coal Prices -10% (and Off Peak Market Energy)	16,616.0	(267.8)	300	0	0	0	604.701	0	0	1100	10	0	647.599
b015	Coal Prices -20% (and Off Peak Market Energy)	16,306.0	(577.8)	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
b016	Coal Prices -30% (and Off Peak Market Energy)	15,968.5	(915.3)	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
b017	New Unit Capital Costs +10%	17,250.5	366.7	300	0	0	0	604.701	0	0	1100	10	0	647.599
b018	New Unit Capital Costs -10%	16,504.9	(378.9)	300	0	0	0	604.701	0	0	1100	10	0	647.599
b019	Higher Wind Prices, +$20/MWH	17,569.6	685.8	500	0	0	0	604.701	0	0	600	10	0	647.599
b020	Higher Wind Prices, +$10/MWH	17,282.9	399.1	300	0	0	0	604.701	0	0	1100	10	0	647.599
b021	Lower Wind Prices, -$10/MWH	16,461.2	(422.6)	300	0	0	0	604.701	0	0	1100	10	0	647.599
b022	Lower Wind Prices, -$20/MWH	16,038.6	(845.2)	300	0	0	0	604.701	0	0	1100	10	0	647.599

Total Additions 2014-2029
"c" series, Minnesota Midpoint 2017 Carbon

				c25	d25	e25	f25	g25	h25	i25	j25	k25	l25	m25
Case	Description	PVRR, $M	PVRR delta from _001	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
c001	Base Assumptions (Reference Case)	17,636.7	-	300	0	0	0	604.701	0	0	1100	10	0	647.599
c002	High Load Forecast	18,764.8	1,128.1	950	0	191.7	0	604.701	0	0	1100	10	0	647.599
c003	Low Load Forecast	16,532.7	(1,103.9)	800	0	191.7	0	0	0	0	1100	10	0	647.599
c004	No Economy Energy	18,169.3	532.7	300	0	0	0	604.701	0	0	1100	10	0	647.599
c005	Natural Gas Prices +10% (and On Peak Market Energy)	17,980.5	343.9	300	0	0	0	604.701	0	0	1100	10	0	647.599
c006	Natural Gas Prices +20% (and On Peak Market Energy)	18,286.5	649.8	300	0	0	0	604.701	0	0	1100	10	0	647.599
c007	Natural Gas Prices +30% (and On Peak Market Energy)	18,589.3	952.6	300	0	0	0	604.701	0	0	1100	10	0	647.599
c008	Natural Gas Prices -10% (and On Peak Market Energy)	17,179.7	(457.0)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c009	Natural Gas Prices -20% (and On Peak Market Energy)	16,613.2	(1,023.5)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c010	Natural Gas Prices -30% (and On Peak Market Energy)	15,977.1	(1,659.6)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c011	Coal Prices +10% (and Off Peak Market Energy)	17,863.3	226.7	300	0	0	0	604.701	0	0	1100	10	0	647.599
c012	Coal Prices +20% (and Off Peak Market Energy)	18,035.6	399.0	300	0	0	0	604.701	0	0	1100	10	0	647.599
c013	Coal Prices +30% (and Off Peak Market Energy)	18,174.4	537.8	300	0	0	0	604.701	0	0	1100	10	0	647.599
c014	Coal Prices -10% (and Off Peak Market Energy)	17,345.3	(291.4)	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
c015	Coal Prices -20% (and Off Peak Market Energy)	17,016.8	(619.9)	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
c016	Coal Prices -30% (and Off Peak Market Energy)	16,684.4	(952.2)	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
c017	New Unit Capital Costs +10%	18,002.9	366.2	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
c018	New Unit Capital Costs -10%	17,257.8	(378.9)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c019	Higher Wind Prices, +$20/MWH	18,346.6	710.0	400	0	0	0	604.701	0	0	600	10	0	647.599
c020	Higher Wind Prices, +$10/MWH	18,051.9	415.3	300	0	0	0	604.701	0	0	1100	10	0	647.599
c021	Lower Wind Prices, -$10/MWH	17,214.1	(422.6)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c022	Lower Wind Prices, -$20/MWH	16,791.5	(845.2)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c023	CO2 Scenario - Minnesota High	18,726.8	1,090.2	300	0	0	0	604.701	0	0	1100	10	0	647.599
c024	CO2 Scenario - Minnesota Low	16,174.5	(1,462.1)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c025	Externalities High	17,643.5	6.8	300	0	0	0	604.701	0	0	1100	10	0	647.599
c026	Externalities Low	17,630.2	(6.5)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c027	50% DSM and Renewables	17,906.4	269.7	800	0	0	0	0	100 MW LFG		1100	300	0	647.599
c028	75% DSM and Renewables	18,197.9	561.3	800	0	0	0	0	100 MW LFG		1100	600	0	647.599
c029	SO2 allowance cost $1,000/ton	17,707.3	70.6	300	0	0	0	604.701	0	0	1100	10	0	647.599
c030	SO2 allowance cost $2,000/ton	17,772.5	135.8	300	0	0	0	604.701	0	0	1100	10	0	647.599
c031	No Forced Solar	17,619.6	(17.0)	300	0	0	0	604.701	0	0	1100	0	0	647.599
c032	No Recent RES additions	17,732.7	96.0	300	0	0	0	604.701	0	0	1100	10	0	647.599

MSN DSM Analysis (DSM costs added outside of EGEAS)
"c" series, Minnesota Midpoint 2017 Carbon

				c25	d25	e25	f25	g25	h25	i25	j25	k25	l25	m25
Case	Description	PVRR, $M	PVRR delta from c033	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
c033	Base MN DSM	17,681.8	-	300	0	0	0	604.701	0	0	1100	10	0	647.599
c034	High MN DSM	17,695.8	14.1	600	0	191.7	299.8	0	0	0	1100	10	0	647.599
c035	Medium MN DSM	17,700.0	18.2	300	0	0	0	604.701	0	0	1100	10	0	647.599
c036	Low MN DSM	17,710.4	28.6	300	0	0	0	604.701	0	0	1100	10	0	647.599

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

[TRADE SECRET DATA BEGINS

Section 6
Appendix 6I
34 Pages

Reference Case Production Costs,
No Carbon Scenario

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

[TRADE SECRET DATA BEGINS

Section 6
Appendix 6J
34 Pages

Reference Case Production Costs,
Wood Mackenzie 2023 Carbon Scenario

TRADE SECRET DATA ENDS]

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

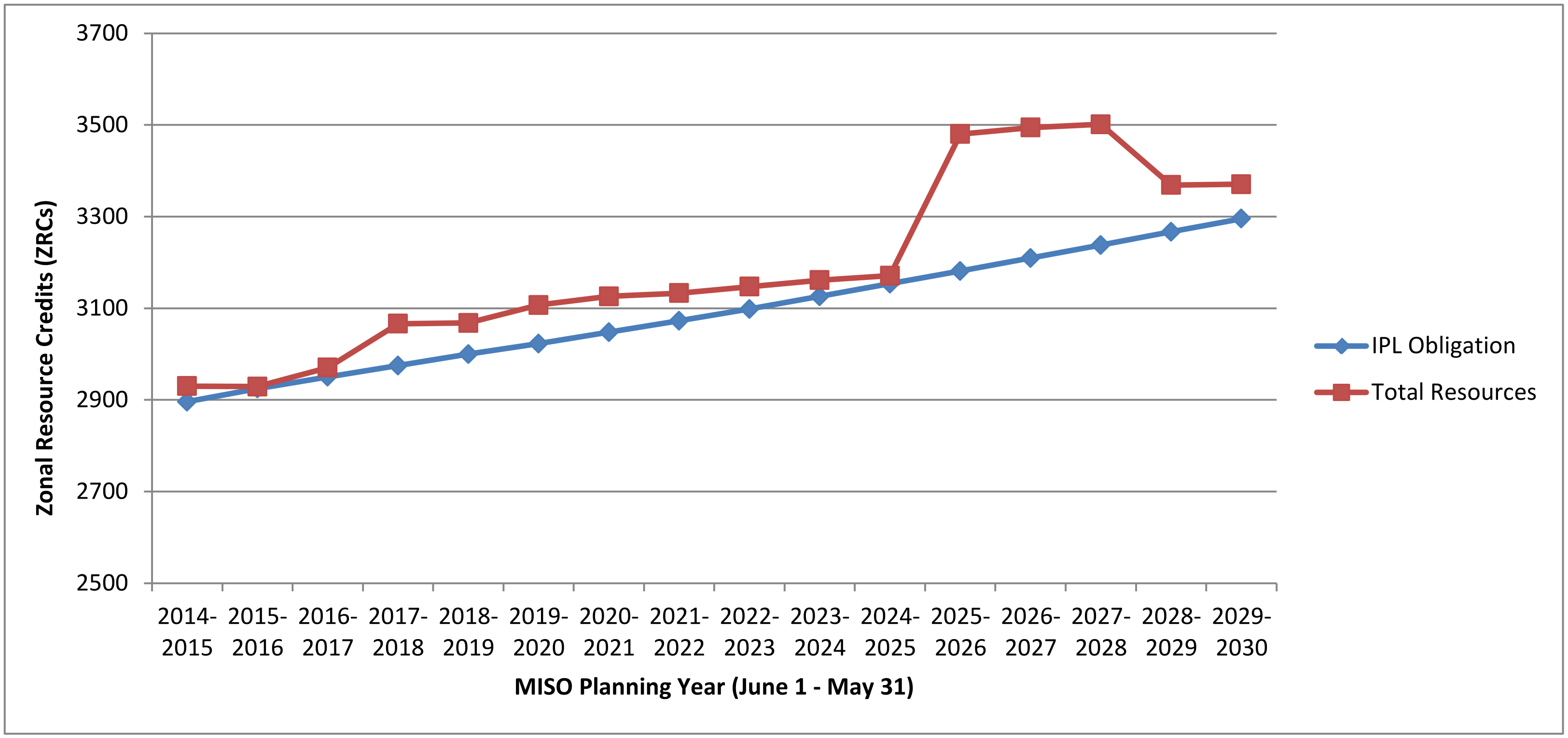
[TRADE SECRET DATA BEGINS

Section 6
Appendix 6K
34 Pages

Reference Case Production Costs,
Minnesota Midpoint 2017 Carbon Scenario

TRADE SECRET DATA ENDS]

Interstate Power and Light Company
2014 Electric Resource Plan
Load and Capability Chart
No Carbon Reference Case (Carbon Cases very similar)
After Resource Additions



[TRADE SECRET DATA BEGINS

Section 6
Appendix 6M
2 Pages

Winter Capacity Outlook

TRADE SECRET DATA ENDS]

ALLIANT ENERGY

Alliant Energy Corporate Service
Legal Department
319.786.4505 – Phone
319.786.4533 – Fax

Kent M. Ragsdale
Managing Attorney – Regulatory

Interstate Power and Light Company
An Alliant Energy Company

Alliant Tower
200 First Street SE
P.O. Box 351
Cedar Rapids, IA 52406-0351

Office: 1.800.822.4348
www.alliantenergy.com

July 1, 2013

Dr. Burl Haar, Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: Interstate Power and Light Company
Docket No. E,G001/D-13-558
Depreciation Petition

Dear Dr. Haar:

Enclosed for e-Filing with the Minnesota Public Utilities Commission, please accept Interstate Power and Light Company's (IPL) petition for approval of its 2013 depreciation rates and methods.

Copies of this filing have been served on the Minnesota Department of Commerce, Division of Energy Resources, the Minnesota Office of Attorney General – Residential and Small Business Utilities Division and the attached service list.

Very truly yours,

<u>/s/ Kent M. Ragsdale</u>
Kent M. Ragsdale
Managing Attorney – Regulatory

KMR/tao
Enclosures

cc: Service List

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	**Chair**
David C. Boyd	**Commissioner**
Nancy Lange	**Commissioner**
J. Dennis O'Brien	**Commissioner**
Betsy Wergin	**Commissioner**

IN THE MATTER OF INTERSTATE POWER AND LIGHT COMPANY'S PETITION FOR APPROVAL OF ITS DEPRECIATION RATES FOR 2013	**DOCKET NO. E,G001/D-13-558**

AFFIDAVIT OF SERVICE

STATE OF IOWA)
) ss.
COUNTY OF LINN)

Tonya A. O'Rourke, being first duly sworn on oath, deposes and states:

That on the 1st day of July, 2013, copies of the foregoing Affidavit of Service, together with Interstate Power and Light Company's Depreciation Petition, were served upon the parties on the attached service list, by e-filing, overnight delivery, electronic mail, and/or first-class mail, proper postage prepaid from Cedar Rapids, Iowa.

/s/ Tonya A. O'Rourke
Tonya A. O'Rourke

Subscribed and Sworn to Before Me
this 1st day of July, 2013.

/s/ Kathleen J. Faine
Kathleen J. Faine
Notary Public
My Commission Expires on February 20, 2015

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Bobby	Adam	bobby.adam@conagrafoods.com	ConAgra	Suite 5022 11 ConAgra Drive Omaha, NE 68102	Paper Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Christopher	Anderson	canderson@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
City	Attorney	N/A	City of Albert Lea	221 E Clark St Albert Lea, MN 56007	Paper Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
William A.	Blazar	bblazar@mnchamber.com	Minnesota Chamber Of Commerce	Suite 1500 400 Robert Street North St. Paul, MN 55101	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Michael	Bradley	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Ronald	Giteck	ron.giteck@ag.state.mn.us	Office of the Attorney General-RUD	Antitrust and Utilities Division 445 Minnesota Street, 1400 BRM Tower St. Paul, MN 55101	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
David	Grover	dgrover@itctransco.com	ITC Midwest	444 Cedar St Ste 1020 Saint Paul, MN 55101-2129	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Linda	Jensen	linda.s.jensen@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota Street St. Paul, MN 551012134	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Jim	Krueger	jkrueger@fmcs.coop	Freeborn-Mower Cooperative Services	Box 611 Albert Lea, MN 56007	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Paper Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Jenny L.	Myers	jmyers@iwla.org	Izaak Walton League of America	1619 Dayton Ave. Suite 202 St. Paul, MN 55104	Paper Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Steven	Nyhus	swnyhus@flaherty-hood.com	Flaherty & Hood PA	525 Park St Ste 470 Saint Paul, MN 55103	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kent	Ragsdale	kentragsdale@alliantenergy.com	Alliant Energy-Interstate Power and Light Company	P.O. Box 351 200 First Street, SE Cedar Rapids, IA 524060351	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Larry L.	Schedin	Larry@LLSResources.com	LLS Resources, LLC	12 S 6th St Ste 1137 Minneapolis, MN 55402	Paper Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Matthew J.	Schuerger P.E.	mjspub@earthlink.net	Energy Systems Consulting Services, LLC	P.O. Box 16129 St. Paul, MN 55116	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Ron	Spangler, Jr.	rlspangler@otpco.com	Otter Tail Power Company	215 So. Cascade St. PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	GEN_SL_Interstate Power and Light Company_Interstate Power and Light Company General Service List

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	**Chair**
David C. Boyd	**Commissioner**
Nancy Lange	**Commissioner**
J. Dennis O'Brien	**Commissioner**
Betsy Wergin	**Commissioner**

IN THE MATTER OF INTERSTATE POWER AND LIGHT COMPANY'S PETITION FOR APPROVAL OF ITS DEPRECIATION RATES FOR 2013	**DOCKET NO. E,G001/D-13-558**

SUMMARY FILING

Please take notice that on July 1, 2013, Interstate Power and Light Company (IPL) filed with the Minnesota Public Utilities Commission (Commission) its petition for approval of its 2013 depreciation rates and methods. IPL requests that upon Commission approval, the new remaining lives and net salvage rates for property physically located in Minnesota will become effective as of January 1, 2013.

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	**Chair**
David C. Boyd	**Commissioner**
Nancy Lange	**Commissioner**
J. Dennis O'Brien	**Commissioner**
Betsy Wergin	**Commissioner**

IN THE MATTER OF INTERSTATE POWER AND LIGHT COMPANY'S PETITION FOR APPROVAL OF ITS DEPRECIATION RATES FOR 2013	**DOCKET NO. E,G001/D-13-558**

**INTERSTATE POWER AND LIGHT COMPANY'S
2013 DEPRECIATION PETITION**

COMES NOW, Interstate Power and Light Company (IPL), and files its petition for approval of its 2013 depreciation rates and methods (2013 Depreciation Study) to be used by IPL pursuant to Minn. Stat. §216B.11, Minnesota Rules, parts 7825.0600 and 7825.0700, and the Minnesota Public Utilities Commission's (Commission) Order in Docket No. E,G001/D-12-680. IPL respectfully requests that upon Commission approval, the new remaining lives and net salvage rates for property physically located in Minnesota will become effective as of January 1, 2013.

I. INTRODUCTION

On October 30, 2012, in Docket No. E,G001/D-12-680, the Commission issued an Order approving IPL's remaining lives as proposed, existing salvage values, and resulting depreciation rates effective January 1, 2012. The Commission's Order also directed IPL to include in its next depreciation filing a schedule comparing remaining lives used for depreciation purposes and the lives used for resource planning purposes and explain any differences between the two lives. (See Part 7 for IPL's table comparing remaining lives used for depreciation purposes and lives used for IPL's most recent resource planning activities, which IPL used to support the Marshalltown Generating Station filings with the Iowa Utilities Board ("IPL's 2012 IRP").)

The cumulative effect of the 2013 depreciation study is an approximate annual increase of $63,581 in IPL's total depreciation expense attributable to its Minnesota jurisdictions.

II. PROCEDURAL REQUIREMENTS

Pursuant to Minn. Rules 7825.3200, 7825.3500, and 7825.1300, subp. 3, IPL provides the following required information.

A. Summary of Filing (Minn. Rule pt. 7829.1300. subp. 1)

A one-paragraph summary of the filing accompanies this petition.

B. Service on Other Parties (Minn. Rule pt. 7829.1300, subp. 2)

IPL has served a copy of this Petition on the Minnesota Department of Commerce, Division of Energy Resources, the Minnesota Office of the Attorney General – Residential and Small Business Utilities Division, and all parties on IPL's miscellaneous electric service list.

C. General Filing Information (Minn Rule pt. 7829.1300, subp. 3)

IPL provides the following required information.

1. Name, Address, and Telephone Number of Utility

Interstate Power and Light Company
Alliant Tower
200 First Street S.E.
P.O. Box 351
Cedar Rapids, Iowa 52406-0351
(319) 786-4411

2. Name, Address, and Telephone Number of Utility Attorney

Kent M. Ragsdale
Managing Attorney – Regulatory
Alliant Tower
200 First Street S.E.
P.O. Box 351
Cedar Rapids, Iowa 52406-0351
(319) 786-7765

3. Date of Filing a Proposed Effective Date

This Petition is being filed on July 1, 2013. IPL respectfully requests that, upon Commission approval, the proposed depreciation rates become effective as of January 1, 2013.

4. Statute Controlling Schedule for Processing the Filing

This Petition is made in accordance with Minn. Stat. §216B.11 and prior Commission decisions, and no statutory time frame is imposed for a Commission decision for this filing.

5. Utility Employee Responsible for Filing

Kent M. Ragsdale
Managing Attorney – Regulatory
Alliant Tower
200 First Street S.E.
P.O. Box 351
Cedar Rapids, Iowa 52406-0351
(319) 786-7765

Robyn Woeste
Manager – Regulatory Affairs
Alliant Tower
200 First Street S.E.
P.O. Box 351
Cedar Rapids, Iowa 52406-0351
(319) 786-4384

III. REVIEW OF REMAINING LIVES & NET SALVAGE

The retirement dates for IPL's electric generating facilities, proposed within this Petition, are based on IPL's understanding of current environmental regulations and its best estimate of future environmental regulations along with operational, market and other factors. Hence, IPL believes those dates represent realistic retirement dates. However, it is possible that significant changes to environmental regulation may occur prior to the planned retirement date of these facilities. It is also possible that significant upgrade costs could be required that would make upgrades uneconomical, thus some of IPL's electric generating facilities may be unable to comply with environmental regulations. Such changes may force retirement prior to the planned retirement date for IPL's electric generating facilities. IPL monitors and plans to continue to monitor environmental policy and regulation, along with operational, market and other factors, and if appropriate, revise retirement dates for these facilities as changes become known and measurable.

A. Change in Remaining Life

IPL is proposing adjustments to the remaining lives and net salvage percentages of certain of its generating facilities in the 2013 Depreciation Study (see Table 1 below for proposed changes to the remaining lives of such units).

IPL completed an evaluation of the remaining lives of its other generating units and determined not to request a change to the remaining lives of these remaining generating units based on current information. As noted above, the expected remaining lives for these other units could be subject to change in the future depending on operational, regulatory, market and other factors including approval by the Midcontinent Independent System Operator, Inc. (MISO) based upon timing of required transmission upgrades. In addition, certain units could be impacted in the future by the potential construction of the Marshalltown Generating Station. Additionally, IPL provides below an overview and status update for each generating unit located in Minnesota and Iowa. (See Part 1 for supporting detail for proposed change in depreciation expense.)

Table 1: IPL Generating Plants – Change in Remaining Life

Generating Plant	Current Retirement Date	Proposed Retirement Date	Estimated Minnesota Depreciation Expense Impact
Steam Production Plant – Iowa			
Neal Generating Station – Unit 3	2027	2035	$(33,007)
Neal Generating Station – Unit 4	2024	2040	$(105,759)
Dubuque Diesels	2019	2014	$1,917
Lansing Generating Station – Unit 3	2012	Retired 2013	$--
Steam Production Plant – Minnesota			
Montgomery Combustion Turbine	2019	Retired 2012	$--

Steam Production Plant: Iowa

a) Burlington Generating Station

Burlington Generating Station is a single unit coal-fired base load plant located in Burlington, Iowa. The single unit began operation in 1968 and has a nameplate rated capacity of 212.0 megawatts (MW). IPL continues to execute various equipment repair and replacement projects associated with the unit that continue to ensure safe and reliable operation. IPL is not requesting a change to the remaining life of this unit.

b) Clinton Generating Station – Unit 2 (also known as M.L. Kapp Unit 2)

The Clinton Generating Station was formerly a two (2) unit coal-fired base load plant located in Clinton, Iowa. Unit 1 began operation in 1947 and was retired in 2010.

Unit 2 began operation in 1967. The nameplate rated capacity of Unit 2 is 218.45 MW. IPL continues to execute various equipment repair and replacement projects associated with Unit 2 that continue to ensure safe and reliable operation. IPL is not requesting a change to the remaining life for this unit.

c) Dubuque Generating Station – Units 3 and 4

The Dubuque Generating Station is a two (2) unit plant located in Dubuque, Iowa. Units 3 and 4 began operation in 1952 and 1959, respectively. The units were converted to natural gas operation in 2011. The nameplate rated capacity of Units 3 and 4 are 28.7 MW and 37.5 MW, respectively. IPL is not requesting a change to the remaining lives for these units.

d) Lansing Generating Station – Units 3 and 4

Lansing Generating Station Unit 4 is a coal-fired base load unit that is located near Lansing, Iowa. It began operation in 1977 and has a nameplate rated capacity of 274.5 MW. IPL installed environmental upgrades on this unit that will significantly reduce nitrogen oxide, particulate matter and mercury emissions. IPL is also undertaking other equipment replacement and repair projects associated with this unit. IPL is not requesting a change to the remaining life for this unit.

Lansing Generating Station Unit 3 was a coal-fired base load unit that was located near Lansing, Iowa. It began operation in 1957 and had a nameplate rated capacity of 37.5 MW. IPL retired Lansing Unit 3 in 2013.

e) Louisa Generating Station – Unit 1

Louisa Generating Station Unit 1 is a coal-fired base load unit operated by MidAmerican Energy Company (MEC), with a total nameplate rated capacity of 811.9 MW. IPL owns 32.4 MW of the capacity from this unit. Louisa Generating Station Unit

1 began operation in 1983. Major expenditures have been made to make environmental upgrades to this unit that will significantly reduce sulfur dioxide, nitrogen oxide, particulate matter, and mercury emissions. IPL is not requesting a change to the remaining life for this unit.

f) Neal Generating Station – Units 3 and 4

Neal Unit 3 is a coal-fired base load unit operated by MEC, with a total nameplate rated capacity of 549.8 MW. IPL owns 153.95 MW of the capacity from Neal Unit 3. Neal Unit 3 began operation in 1975. Major expenditures are occurring for environmental upgrades to this unit that will significantly reduce nitrogen oxide, particulate matter, and mercury emissions and performance upgrades to this unit to increase its capacity. The current estimated in-service date for these major environmental expenditures at Neal 3 is the second quarter of 2014. IPL is requesting that the remaining life for this unit be increased by eight years to reflect the extension of the expected retirement date from 2027 to 2035 due to the recent major expenditures. The expected retirement date of 2035 is consistent with the remaining life used by the operator (MEC) of the generating unit.

Neal Unit 4 is a coal-fired base load unit operated by MEC, with a total nameplate rated capacity of 640 MW. IPL owns 164.70 MW of the capacity from Neal Unit 4. This unit began operation in 1979. Major expenditures are occurring for environmental upgrades to this unit that will significantly reduce sulfur dioxide, nitrogen oxide, particulate matter, and mercury emissions and performance upgrades to this unit to increase its capacity. The current estimated in-service date for these major environmental expenditures at Neal 4 is the fourth quarter of 2013. IPL is requesting that the remaining life for this unit be increased by sixteen years to reflect the extension of the expected retirement date from 2024 to 2040 due to the recent major expenditures. The expected retirement date of 2040 is consistent with the remaining life used by the operator (MEC) of the generating unit.

g) Ottumwa Generating Station

Ottumwa Generating Station is a single unit coal-fired base load plant located in Chillicothe, Iowa. The unit began operation in 1981, has a nameplate rated capacity of 726 MW and is jointly owned with MEC. IPL is the operator of the plant and owns 348.4 MW of the total capacity. Major expenditures are occurring for environmental upgrades to this unit that will significantly reduce sulfur dioxide and mercury emissions and performance upgrades to this unit to increase its capacity. IPL is not requesting a change to the remaining life for this unit.

h) Prairie Creek Generating Station – Units 1, 3 and 4

Prairie Creek Generating Station is a three (3) unit coal-fired base load plant located in Cedar Rapids, Iowa. Units 1, 3 and 4 began operation in 1997, 1958 and 1968, respectively. Their nameplate rated capacities are 14.6 MW, 50 MW and 148.8 MW, respectively. The station produces electric energy on behalf of IPL's customers and also produces and distributes steam energy to a limited number of industrial customers located in close proximity to the station. IPL is not requesting a change to the remaining lives for these units.

i) Sutherland Generating Station – Units 1 and 3

Sutherland Generating Station is a two (2) unit plant located in Marshalltown, Iowa. Sutherland Unit 1 began operation in 1955 and has a nameplate rated capacity of 37.5 MW. IPL converted this unit to natural gas operation in 2012. IPL is not requesting a change to the remaining life for this unit.

Sutherland Unit 3 began operation in 1961 and has a nameplate rated capacity of 81.6 MW. In 2012, IPL converted the operation of this unit to natural gas. IPL is not requesting a change to the remaining life for this unit.

Other Production Plant: Iowa

a) Burlington Combustion Turbines

The four (4) Burlington Combustion Turbines are natural gas fired peaking units. They are located at the Burlington Generating Station near Burlington, Iowa. These units were purchased as used combustion turbines by IPL and placed in service in 1994 through 1996. Each of the four units has a nameplate rated capacity of 19.7 MW. IPL is not requesting a change to the remaining lives for these units.

b) Centerville Diesels

The Centerville Diesels are three (3) oil-fired peaking units that were placed into service in 1963. They are located near Centerville, Iowa. Each unit has a nameplate rated capacity of 2 MW. IPL is not requesting a change to the remaining lives for these units.

c) Centerville Combustion Turbines

The two (2) Centerville Combustion Turbines are oil-fired peaking units. They are located near Centerville, Iowa. These units were purchased as used combustion turbines by IPL and placed into service in 1990. Each unit has a nameplate rated capacity of 27.0 MW. IPL is not requesting a change to the remaining lives for these units.

d) Dubuque Diesels

The Dubuque Diesels are two (2) oil-fired peaking units that were placed in service in 1966. They are located in Dubuque, Iowa, at the Dubuque Generating

Station. Each unit has a nameplate rated capacity of 2 MW. IPL is requesting that the remaining lives for these units be decreased by 5 years to reflect that the retirement date has been changed from 2019 to 2014. The change in the estimated remaining lives is consistent with the remaining lives of Dubuque Units 3 and 4.

e) Emery Generating Station

The Emery Generating Station is a natural gas-fired peaking plant. It is located near Clear Lake, Iowa. It has a total nameplate rated capacity of 602.8 MW. It began operation in 2004. IPL is not requesting a change to the remaining life for this unit.

f) Grinnell Combustion Turbines

The two (2) Grinnell Combustion Turbines are natural gas-fired peaking units. They are located near Grinnell, Iowa. These units were purchased used by IPL and placed in service in 1990 and 1991. Each unit has a nameplate rated capacity of 23.8 MW. IPL is not requesting a change to the remaining lives for these units.

g) Lime Creek Combustion Turbines

The two (2) Lime Creek Combustion Turbines are oil-fired peaking units. These units are located near Mason City, Iowa. Both began operation in 1991. Each unit has a nameplate rated capacity of 45.1 MW. IPL is not requesting a change to the remaining lives for these units.

h) Sutherland Combustion Turbines

The three (3) Sutherland Combustion Turbines are oil-fired peaking units. They are located at the same site as the Sutherland Generating Station near Marshalltown, Iowa. These units began operation in 1978. Each of the three units has a nameplate rated capacity of 63.0 MW. IPL is not requesting a change to the remaining lives for these units.

i) Red Cedar Station

The Red Cedar Station is a natural gas-fired peaking unit. It is located in Cedar Rapids, Iowa. It is a used unit that began IPL operation in 1996. It has a nameplate rated capacity of 22.5 MW. IPL is not requesting a change to the remaining life for this unit.

Wind Generation: Iowa

a) Whispering Willow Wind Farm – East

The Whispering Willow Wind Farm – East is located in Franklin County, Iowa. It was placed into operation in 2009. It has a total nameplate rated capacity of 199.7 MW. IPL is not requesting a change to the remaining life for this unit.

Steam Production Plant: Minnesota

a) Fox Lake Generating Station – Unit 3

Fox Lake Unit 3 is a gas-fired peaking unit that began operation in 1962. It has a nameplate rated capacity of 81.6 MW. IPL is not requesting a change to the remaining life for this unit.

Other Production Plant: Minnesota

a) Hills Diesels

The Hills Diesels are two (2) oil-fired peaking units. Units 1 and 2 began operation in 1996 and 1960, respectively. Each has a nameplate rated capacity of 2 MW. IPL is not requesting a change to the remaining lives for these units.

b) Montgomery Combustion Turbine

The Montgomery Combustion Turbine was an oil-fired peaking unit. It was located near Montgomery, Minnesota. It began operation in 1974. It had a nameplate rated capacity of 28.8 MW. The Montgomery Combustion Turbine was retired in 2012.

B. Change in Survivor Curve, Composite Remaining Life, and Net Salvage Rates

Part 6 sets forth the comparison of the composite remaining life by location or account for the calculations performed as of December 31, 2011 and December 31, 2012. As shown by the shaded cells, there are some composite remaining lives that changed more than expected from one year to another. An explanation for each of those situations follows:

MINNESOTA

Electric Plant

The composite remaining life for Account 391.1, Office Furniture and Equipment – Except Computers, changed from 5.1 to 13.7 years due to large additions in 2012 which affected the plant to reserve ratio.

Gas Plant

The composite remaining life change for Account 375, Structures and Improvements, from 19.9 to 37.5 years is due to large additions in 2012 which affected the plant to reserve ratio.

IOWA

Electric Plant

Each of composite remaining lives for Steam Accounts 311 through 316 that experienced a larger than expected change was related to Neal Unit 3 & 4 which had a change in remaining lives. The composite remaining life change for Prairie Creek Unit 4 Account 312.5 from 0 to 1.5 years relates to a reserve reallocation. The composite remaining lives for Other Production Accounts 341 through 346 related to the Dubuque

Diesels which had a change in remaining lives. The composite remaining life change for Centerville CT Units 1 & 2, Account 344 relates to a reserve reallocation.

Gas Plant

The composite remaining life for Account 375, Structures and Improvements, changed from 38.1 to 41 years due to large additions in 2012 that affected the plant to reserve ratio. The change in composite remaining life for Account 379, Measuring and Regulating Station Equipment – City Gate, is due to large additions in 2012 that affected the plant to reserve ratio. The composite remaining life for Account 382, Meter Installations, changed from 29.1 to 25.8 years due to the reclassification of assets from Account 380, Services.

Common Plant

The change in composite remaining life for Account 393, Stores Equipment, from 0.0 to 4.5 years was the result of high retirements which affected the plant to reserve ratio. The composite remaining life for Account 397, Communication Equipment – Towers/Buildings, changed from 21.4 to 19.8 years due to large additions and transfers in 2012.

IV. DISCUSSION OF FUTURE ENVIRONMENTAL RULES ON EXISTING UNITS

On December 21, 2011, the United States Environmental Protection Agency (EPA) issued final Mercury and Air Toxic Standards (MATS). The final rule requires compliance with emission limits (on a pound per MMBTU basis, or TBTU for mercury) at IPL's coal-fired electric generating units for mercury, filterable PM as a substitute for non-mercury metal hazardous air pollutants (HAPs), and hydrogen chloride (HCl) as a substitute for acid gas HAPs. The EPA also proposed alternative standards for total or individual non-mercury metals emissions (instead of filterable PM) and SO_2 emissions (instead of HCl for acid gases if a scrubber is installed). In addition, work practice standards were proposed for organic HAPs emissions to ensure proper combustion. Compliance is required by April 16, 2015. However, an entity can request an additional year for compliance, which may be granted on a case-by-case basis by state permitting authorities for units that are needed to assure power reliability, units needed while building replacement generation or repowering to gas, or units that need additional time to install air emission controls technology. The final rule is subject to legal challenge that is pending in the D.C. Circuit Court and the impact of future court rulings regarding this rule is uncertain.

The Clean Air Interstate Rule (CAIR) includes a regional cap-and-trade system covering the eastern U.S., where compliance may be achieved by either adding emission controls and/or purchasing emission allowances. In 2011, the EPA issued the Cross State Air Pollution Rule (CSAPR) as a replacement to resolve flaws with CAIR identified in a 2008 opinion issued in response to legal challenges to this rule. This rule similarly included requirements to reduce SO_2 and NO_x (both annual and ozone season) emissions. IPL's fossil-fueled EGUs with greater than 25 MW of capacity located in Iowa and Minnesota would have been impacted by CSAPR requirements. Unlike MATS, CAIR (or CSAPR) would not require IPL to meet specific SO_2 and NO_x emissions requirements at each of its fossil fuel-fired power plants. However, IPL must reduce aggregate SO_2 and NO_x emissions from its fossil fuel-fired power plants to avoid purchasing significant quantities of emission allowances to comply.

In December 2011, the D.C. Circuit Court stayed the implementation of CSAPR before it took effect. In August 2012, it was formally vacated and remanded for further revision to the EPA. The D.C. Circuit Court order required the EPA to continue administering CAIR pending the promulgation of a valid replacement for CSAPR. In June 2013, the Supreme Court issued an order granting the EPA's petition requesting review of the D.C. Circuit's decision vacating the CSAPR. The Supreme Court ruling on the CSAPR vacatur is not expected until late in 2013 or 2014. The current CAIR program remains as the effective regulation during the interim. The impact of future Court rulings regarding this rule is uncertain; however, IPL anticipates that CAIR will be replaced in the future, either by a modified CSAPR or another rule that addresses the interstate transport of air pollutants.

Environmental rules and regulations addressing power plant cooling water intake structures, water discharge, coal combustion residuals (CCR) and greenhouse gas (GHG) emissions at existing electric generating units are also expected at some future date. A final rule, commonly referred to as 316(b) and anticipated to be issued by EPA in mid-2013, would require many IPL units to install control equipment at power plant intake structures to minimize the impacts on aquatic life present in source water. EPA is expected to issue new water quality discharge requirements, referred to as Effluent Limitation Guidelines (ELG), in May, 2014. The ELG would require operational and physical changes at many IPL facilities, which may possibly include ceasing the discharge of certain wastewaters. New CCR rules are also expected, the timing of which are uncertain at this time, but appear to be linked to the timing of the ELG rulemaking requirements because both rules would require changes in the handling of certain CCR processes.

As part of its November 2010 Integrated Resource Plan (IRP) in Commission Docket E001/EP-08-673, IPL introduced the concept of a tiered approach to evaluating its power plants. The Tier concept consists of 3 tiers – Tier 1, Tier 2, and Tier 3.

- Tier 1 Units are larger, newer, and more efficient units that the company plans to install emissions controls upon as environmental rules dictate, improve the efficiency of the units and prepare for an additional 20+ years of operations. Tier 1 Units are: Ottumwa, Lansing Unit 4, Louisa Unit 1, Neal Unit 3, and Neal Unit 4.

- Tier 2 Units are units that likely cannot withstand the economics of a full set of controls to meet environmental rules. Some Tier 2 Units may be able to withstand low-cost emissions controls, others may be candidates for fuel switching, and others may be candidates for retirement. Tier 2 Units are: Burlington, Clinton Unit 2, Prairie Creek Unit 4, and Sutherland Unit 3

- Tier 3 Units are units that are typically older, smaller, and less efficient and cannot economically withstand any expenditure associated with environmental controls. Tier 3 units may be candidates for fuel switching and are expected to be retired as dictated by operational considerations and environmental rules.

IPL's Tier 1 Units are either already equipped with emissions control equipment or construction projects are underway to install emissions control equipment that is expected to enable the units to comply with MATS. IPL completed testing and engineering analyses at certain of its Tier 2 Units and is in the process of implementing lower-cost emission controls that will enable such Tier 2 Units to comply with MATS. These lower-cost emission controls include activated carbon injection systems to reduce mercury emissions and modifications to the structure or operation of the electrostatic precipitators to reduce filterable particulate matter emissions. IPL's Tier 3 Units will either convert to operation on natural gas or cease operations. These changes will avoid the need for Tier 3 Units to comply with MATS.

Combustion optimization systems that reduce the formation of NO_x previously installed on many of IPL's units and the Lansing Unit 4 selective catalytic reduction (SCR) system have reduced NO_x emissions. Scrubbers or flue gas desulfurization systems (FGD) to reduce SO_2 emissions are either installed, under construction or planned at IPL Tier 1 Units. These controls will sufficiently reduce aggregate IPL emissions to enable

IPL to avoid purchasing significant quantities of NOx or SO_2 emission allowances to comply with CAIR or CSAPR as currently written or some modified version of such rule.

Similarly, the tiered unit approach will be utilized as IPL develops plans to comply with cooling water (316(b)), ELG, CCR and GHG rulemaking requirements.

V. DESCRIPTION OF IPL'S PROPOSED REVISION IN DEPRECIATION RATES

The following information provides a summary of the attached 2013 Depreciation Study related to IPL's electric, gas and common plant. IPL proposes a revision in its book depreciation rates for all property allocated to the Minnesota jurisdiction.

IPL's methodology for its proposed revisions for most accounts is based on the straight line method using the average service life procedure and the remaining life basis. For certain General and Common Plant accounts, the annual depreciation was based on amortization accounting. These methods are implemented by estimating probable retirement dates, survivor curves and net salvage of the property and then spreading the remaining depreciable investment, adjusted for salvage, over the remaining life. Valuation and Rate Division of Gannett Fleming, Inc. (Gannett Fleming) have reviewed IPL's estimated remaining life of the property, using a working knowledge of each account, in arriving at the proposed depreciation rate revisions contained in the 2013 Depreciation Study.

IPL has not changed any of its methodologies for determining salvage values, depreciation rates or average service lives. In support of IPL's proposed revised depreciation rates, the following supporting schedules are enclosed:

Part 1) Proposed change in depreciation expense which includes 2013 accrual rate changes. This schedule also includes the annual depreciation expense for each account using both the present 2012 and proposed 2013 annual depreciation rates for Minnesota plant balances at December 31, 2012.

Part 2) A summary of estimated survivor curves, net salvage, original cost, book depreciation reserve and calculated annual depreciation rates as of December 31, 2012, prepared by Gannett Fleming.

Part 3) Plant in service for the State of Minnesota, electric, gas and common for December 31, 2012.

Part 4) Accumulated Reserve for Depreciation for the State of Minnesota, electric, gas and common for December 31, 2012.

Part 5) Major changes to property in 2012 and estimated future major additions or retirements in 2013.

Part 6) Summary of changes of estimated survivor curves, net salvage, and composite remaining life (excluding one year passage of time).

Part 7) A table comparing the resource planning lives and remaining lives for purposes of depreciation.

WHEREFORE, IPL respectfully requests the Commission certify IPL's proposed revision in its depreciation rates and methods and authorize IPL to make the necessary adjustment for book accrual purposes reflecting the proposed revised rates of depreciation as set forth in IPL's Petition, to become effective January 1, 2013.

Dated this 1st day of July, 2013.

Respectfully submitted,

Interstate Power and Light Company

By: /s/ Kent M. Ragsdale

Kent M. Ragsdale
Managing Attorney – Regulatory
Alliant Energy Corporate Services, Inc.
200 First Street S.E.
Cedar Rapids, IA 52406-0351
(319) 786-7765
KentRagsdale@alliantenergy.com

Part 1: Proposed change in depreciation expense
December 31, 2012

INTERSTATE POWER AND LIGHT COMPANY
COMPARISON OF DEPRECIATION EXPENSE CALCULATED USING CURRENT AND PROPOSED DEPRECIATION RATES

ACCOUNT	LOCATION/ACCOUNT NAME	UNIT	ALLOCATOR (a)	PLANT BALANCE 12/31/2012 (b)	MINNESOTA PORTION OF PLANT BALANCE (c) (a)*(b)	MINNESOTA PORTION OF PROPOSED DEPRECIATION: BASE RATE % (d)	MINNESOTA PORTION OF PROPOSED DEPRECIATION: AMOUNT (e) ((c)*(d))/100	MINNESOTA PORTION OF CURRENT DEPRECIATION: BASE RATE % (f)	MINNESOTA PORTION OF CURRENT DEPRECIATION: AMOUNT (g) ((c)*(f))/100	Expense Increase (Decrease): BASE RATE CHANGE (h) (d)-(f)	Expense Increase (Decrease): AMOUNT (i) (e)-(g)
	ELECTRIC PLANT										
	STEAM PRODUCTION PLANT										
	BURLINGTON STATION										
311.00	STRUCTURES AND IMPROVEMENTS		6.24%	12,803,578	798,943	5.25	41,945	4.84	38,668	0.41	3,276
312.00	BOILER PLANT EQUIPMENT		6.24%	59,807,931	3,732,015	4.47	166,821	4.34	161,881	0.13	4,940
312.50	BOILER PLANT EQUIPMENT - COMBUSTION INITIATIVE		6.24%	6,208,029	387,381	10.22	39,590	10.17	39,406	0.05	185
314.00	TURBOGENERATOR UNITS		6.24%	18,759,626.09	1,170,601	6.41	75,036	6.06	70,935	0.35	4,100
315.00	ACCESSORY ELECTRIC EQUIPMENT		6.24%	7,629,894	476,105	7.13	33,946	6.46	30,733	0.67	3,213
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT		6.24%	4,328,129	270,075	3.74	10,101	3.73	10,067	0.01	34
				109,537,187	6,835,120		367,439		351,691		15,748
	CLINTON (ML KAPP)										
311.00	STRUCTURES AND IMPROVEMENTS	Unit 2	6.24%	10,521,583	656,547	3.87	25,408	3.75	24,631	0.12	778
312.00	BOILER PLANT EQUIPMENT	Unit 2	6.24%	50,853,247	3,173,243	4.38	138,988	4.17	132,332	0.21	6,656
312.50	BOILER PLANT EQUIPMENT - COMBUSTION INITIATIVE	Unit 2	6.24%	13,619,219	849,839	9.97	84,729	11.24	95,515	(1.27)	(10,786)
314.00	TURBOGENERATOR UNITS	Unit 2	6.24%	19,902,814	1,241,936	6.65	82,589	6.53	81,044	0.12	1,545
315.00	ACCESSORY ELECTRIC EQUIPMENT	Unit 2	6.24%	5,348,773	333,763	2.38	7,944	2.38	7,937	0.00	7
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	Unit 2	6.24%	4,168,714	260,128	4.95	12,876	4.05	10,536	0.90	2,340
				104,414,351	6,515,455		352,534		351,995		539
	FOX LAKE										
311.00	STRUCTURES AND IMPROVEMENTS	Unit 1	6.24%	530,218	33,086	-	-	-	-	-	-
312.00	BOILER PLANT EQUIPMENT	Unit 1	6.24%	973,684	60,758	-	-	-	-	-	-
314.00	TURBOGENERATOR UNITS	Unit 1	6.24%	760,757	47,471	-	-	-	-	-	-
315.00	ACCESSORY ELECTRIC EQUIPMENT	Unit 1	6.24%	238,295	14,870	-	-	-	-	-	-
316.00	MISCELLANEOUS PLANT EQUIPMENT	Unit 1	6.24%	29,650	1,850	-	-	-	-	-	-
		Total Unit 1		2,532,604	158,034		-		-		-
311.00	STRUCTURES AND IMPROVEMENTS	Unit 3	6.24%	2,866,334	178,859	0.51	912	0.49	874	0.02	38
312.00	BOILER PLANT EQUIPMENT	Unit 3	6.24%	12,925,615	806,558	1.90	15,325	1.48	11,913	0.42	3,412
314.00	TURBOGENERATOR UNITS	Unit 3	6.24%	4,012,870	250,403	0.90	2,254	0.87	2,182	0.03	72
315.00	ACCESSORY ELECTRIC EQUIPMENT	Unit 3	6.24%	1,689,253	105,409	1.03	1,086	0.62	652	0.41	434
316.00	MISCELLANEOUS PLANT EQUIPMENT	Unit 3	6.24%	545,896	34,064	4.27	1,455	3.76	1,281	0.51	173
		Total Unit 3		22,039,969	1,375,294		21,031		16,901		4,129
311.00	STRUCTURES AND IMPROVEMENTS	Units 1 & 3	6.24%	67,759	4,228	14.06	594	15.55	658	(1.49)	(63)
312.00	BOILER PLANT EQUIPMENT	Units 1 & 3	6.24%	101,583	6,339	11.97	759	9.60	609	2.37	150
314.00	TURBOGENERATOR UNITS	Units 1 & 3	6.24%	10,423	650	6.18	40	7.39	48	(1.21)	(8)
315.00	ACCESSORY ELECTRIC EQUIPMENT	Units 1 & 3	6.24%	696,395	43,455	2.78	1,208	3.15	1,367	(0.37)	(159)
316.00	MISCELLANEOUS PLANT EQUIPMENT	Units 1 & 3	6.24%	451,226	28,157	7.98	2,247	8.45	2,380	(0.47)	(133)
		Total Units 1 & 3		1,327,385	82,829		4,848		5,061		(213)
		Total Fox Lake		25,899,958	1,616,157		25,879		21,962		3,917
	LANSING										
311.00	STRUCTURES AND IMPROVEMENTS	Unit 3	6.24%	1,097,464	68,482	-	-	-	0	-	-
312.00	BOILER PLANT EQUIPMENT	Unit 3	6.24%	5,326,063	332,346	-	-	-	0	-	-
314.00	TURBOGENERATOR UNITS	Unit 3	6.24%	2,439,453	152,222	-	-	-	0	-	-
315.00	ACCESSORY ELECTRIC EQUIPMENT	Unit 3	6.24%	632,914	39,494	-	-	-	0	-	-
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	Unit 3	6.24%	223,321	13,935	-	-	-	0	-	-
		Total Unit 3		9,719,215	606,479		-		0		-
311.00	STRUCTURES AND IMPROVEMENTS	Unit 4	6.24%	27,732,201	1,730,489	1.70	29,418	1.67	28,899	0.03	519
312.00	BOILER PLANT EQUIPMENT	Unit 4	6.24%	292,380,169	18,244,523	4.02	733,430	3.99	727,956	0.03	5,473
312.50	BOILER PLANT EQUIPMENT - COMBUSTION INITIATIVE	Unit 4	6.24%	1,462,684	91,271	8.99	8,205	9.26	8,452	(0.27)	(247)
314.00	TURBOGENERATOR UNITS	Unit 4	6.24%	22,469,321	1,402,086	1.86	26,079	1.75	24,536	0.11	1,542
315.00	ACCESSORY ELECTRIC EQUIPMENT	Unit 4	6.24%	9,172,259	572,349	0.99	5,666	1.15	6,582	(0.16)	(916)
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	Unit 4	6.24%	3,896,027	243,112	2.06	5,008	2.00	4,862	0.06	146
		Total Unit 4		357,112,660	22,283,830		807,807		801,288		6,518
311.00	STRUCTURES AND IMPROVEMENTS	Units 3 - 4	6.24%	226,358	14,125	4.64	655	4.95	699	(0.31)	(44)
312.00	BOILER PLANT EQUIPMENT	Units 3 - 4	6.24%	3,326,798	207,592	3.63	7,536	3.58	7,432	0.05	104
314.00	TURBOGENERATOR UNITS	Units 3 - 4	6.24%	135,297	8,443	4.00	338	3.91	330	0.09	8
315.00	ACCESSORY ELECTRIC EQUIPMENT	Units 3 - 4	6.24%	1,569,395	97,930	1.86	1,822	1.80	1,763	0.06	59
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	Units 3 - 4	6.24%	2,472,942	154,312	3.51	5,416	3.50	5,401	0.01	15
		Total Units 3 - 4		7,730,790	482,401		15,767		15,625		142
		Total Lansing		374,562,665	23,372,710		823,573		816,913		6,660
	LOUISA										
311.00	STRUCTURES AND IMPROVEMENTS	Unit 1	6.24%	5,970,494	372,559	0.89	3,316	2.87	10,675	(1.98)	(7,360)
312.00	BOILER PLANT EQUIPMENT	Unit 1	6.24%	21,041,271	1,312,975	2.51	32,956	1.65	21,728	0.86	11,228
314.00	TURBOGENERATOR UNITS	Unit 1	6.24%	5,028,421	313,773	2.11	6,621	2.04	6,398	0.07	223
315.00	ACCESSORY ELECTRIC EQUIPMENT	Unit 1	6.24%	2,646,485	165,141	1.47	2,428	1.47	2,434	(0.00)	(6)
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	Unit 1	6.24%	169,697	10,589	2.46	260	2.44	258	0.02	2
				34,856,367	2,175,037		45,580		41,493		4,088
	NEAL										
311.00	STRUCTURES AND IMPROVEMENTS	Unit 3	6.24%	5,078,324	316,887	1.94	6,148	2.88	9,127	(0.94)	(2,980)
312.00	BOILER PLANT EQUIPMENT	Unit 3	6.24%	37,697,258	2,352,309	1.96	46,105	2.81	66,047	(0.85)	(19,941)
314.00	TURBOGENERATOR UNITS	Unit 3	6.24%	10,481,192	654,026	1.55	10,137	2.37	15,500	(0.82)	(5,362)
315.00	ACCESSORY ELECTRIC EQUIPMENT	Unit 3	6.24%	5,559,533	346,915	2.59	8,985	3.94	13,684	(1.35)	(4,699)
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	Unit 3	6.24%	196,174	12,241	0.93	114	1.14	139	(0.21)	(25)
		Total Unit 3		59,012,481	3,682,379		71,489		104,497		(33,007)
311.00	STRUCTURES AND IMPROVEMENTS	Unit 4	6.24%	13,106,494	817,845	1.67	13,658	3.76	30,726	(2.09)	(17,068)
312.00	BOILER PLANT EQUIPMENT	Unit 4	6.24%	58,916,625	3,676,397	1.44	52,940	3.27	120,132	(1.83)	(67,192)
314.00	TURBOGENERATOR UNITS	Unit 4	6.24%	13,564,544	846,428	1.26	10,665	2.86	24,210	(1.60)	(13,545)
315.00	ACCESSORY ELECTRIC EQUIPMENT	Unit 4	6.24%	9,546,268	595,687	0.93	5,540	2.07	12,321	(1.14)	(6,781)
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	Unit 4	6.24%	1,175,429	73,347	1.32	968	2.92	2,141	(1.60)	(1,173)
		Total Unit 4		96,309,361	6,009,704		83,771		189,530		(105,759)
		Total Neal		155,321,842	9,692,083		155,260		294,027		(138,766)

INTERSTATE POWER AND LIGHT COMPANY
COMPARISON OF DEPRECIATION EXPENSE CALCULATED USING CURRENT AND PROPOSED DEPRECIATION RATES

ACCOUNT	LOCATION/ACCOUNT NAME	UNIT	ALLOCATOR (a)	PLANT BALANCE 12/31/2012 (b)	MINNESOTA PORTION OF PLANT BALANCE (c) (a)*(b)	MINNESOTA PORTION OF PROPOSED DEPRECIATION: BASE RATE % (d)	MINNESOTA PORTION OF PROPOSED DEPRECIATION: AMOUNT (e) ((c)*(d))/100	MINNESOTA PORTION OF CURRENT DEPRECIATION: BASE RATE % (f)	MINNESOTA PORTION OF CURRENT DEPRECIATION: AMOUNT (g) ((c)*(f))/100	Expense Increase (Decrease): BASE RATE CHANGE (h) (d)-(f)	Expense Increase (Decrease): AMOUNT (i) (e)-(g)
	OTTUMWA										
311.00	STRUCTURES AND IMPROVEMENTS		6.24%	45,029,568	2,809,845	3.00	84,295	2.83	79,518	0.17	4,777
312.00	BOILER PLANT EQUIPMENT		6.24%	120,486,138	7,518,335	3.38	254,120	3.12	234,549	0.26	19,570
312.50	BOILER PLANT EQUIPMENT - COMBUSTION INITIATIVE		6.24%	15,821,340	987,252	10.06	99,318	10.07	99,395	(0.01)	(77)
314.00	TURBOGENERATOR UNITS		6.24%	32,859,954	2,050,461	2.49	51,056	2.49	50,970	0.00	87
315.00	ACCESSORY ELECTRIC EQUIPMENT		6.24%	18,730,394	1,168,777	2.28	26,648	2.28	26,679	(0.00)	(31)
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT		6.24%	3,490,762	217,824	2.79	6,077	2.79	6,067	0.00	11
				236,418,156	14,752,493		521,514		497,177		24,338
	PRAIRIE CREEK										
311.00	STRUCTURES AND IMPROVEMENTS	Unit 4	6.24%	561,370	35,030	1.07	375	1.15	403	(0.08)	(29)
312.00	BOILER PLANT EQUIPMENT	Unit 4	6.24%	58,929,408	3,677,195	2.07	76,118	1.91	70,379	0.16	5,739
312.50	BOILER PLANT EQUIPMENT - COMBUSTION INITIATIVE	Unit 4	6.24%	852,950	53,224	5.74	-	-	-	5.74	-
314.00	TURBOGENERATOR UNITS	Unit 4	6.24%	10,598,132	661,323	1.78	11,772	1.68	11,123	0.10	649
315.00	ACCESSORY ELECTRIC EQUIPMENT	Unit 4	6.24%	6,002,998	374,567	0.85	3,184	1.19	4,453	(0.34)	(1,269)
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	Unit 4	6.24%	1,158,942	72,318	0.33	-	-	0	0.33	-
		Total Unit 4		78,103,800	4,873,677		91,448		86,358		5,090
311.00	STRUCTURES AND IMPROVEMENTS	Units 1, 3, 4	6.24%	26,158,852	1,632,312	3.62	59,090	3.66	59,749	(0.04)	(659)
312.00	BOILER PLANT EQUIPMENT	Units 1, 3, 4	6.24%	19,657,620	1,226,635	4.65	57,039	4.64	56,885	0.01	154
312.10	BOILER PLANT EQUIPMENT - UNIT TRAIN	Units 1, 3, 4	6.24%	6,822,660	425,734	3.14	13,368	3.16	13,445	(0.02)	(77)
314.00	TURBOGENERATOR UNITS	Units 1, 3, 4	6.24%	1,565,562	97,691	3.73	3,644	3.70	3,610	0.03	34
315.00	ACCESSORY ELECTRIC EQUIPMENT	Units 1, 3, 4	6.24%	29,839,738	1,862,000	3.81	70,942	3.81	70,912	0.00	30
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	Units 1, 3, 4	6.24%	6,116,997	381,701	3.41	13,016	3.36	12,824	0.05	192
		Total Units 1, 3, 4		90,161,428	5,626,073		217,098		217,425		(326)
312.00	BOILER PLANT EQUIPMENT	Units 1, 3	6.24%	41,503,506	2,589,819	4.29	111,103	4.23	109,635	0.06	1,468
312.50	BOILER PLANT EQUIPMENT - COMBUSTION INITIATIVE	Units 1, 3	6.24%	4,504,776	281,098	10.21	28,700	10.22	28,729	(0.01)	(29)
314.00	TURBOGENERATOR UNITS	Units 1, 3	6.24%	5,636,697	351,730	2.79	9,813	2.82	9,907	(0.03)	(94)
315.00	ACCESSORY ELECTRIC EQUIPMENT	Units 1, 3	6.24%	10,773,196	672,247	3.17	21,310	3.19	21,474	(0.02)	(164)
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	Units 1, 3	6.24%	461,445	28,794	0.85	245	0.90	258	(0.05)	(13)
		Total Units 1, 3		62,879,621	3,923,688		171,172		170,003		1,168
		Total Prairie Creek		**231,144,848**	**14,423,439**		479,718		473,786		5,932
	SUTHERLAND										
312.00	BOILER PLANT EQUIPMENT	Unit 1	6.24%	7,352,175	458,776	10.60	48,630	7.84	35,949	2.76	12,681
314.00	TURBOGENERATOR UNITS	Unit 1	6.24%	2,255,330	140,733	4.77	6,713	3.36	4,722	1.41	1,991
315.00	ACCESSORY ELECTRIC EQUIPMENT	Unit 1	6.24%	1,901,852	118,676	34.41	40,836	25.39	30,126	9.02	10,710
		Total Unit 1		11,509,357	718,184		96,179		70,798		25,381
311.00	STRUCTURES AND IMPROVEMENTS	Units 1 & 3	6.24%	13,692,494	854,412	3.91	33,407	3.65	31,220	0.26	2,187
312.00	BOILER PLANT EQUIPMENT	Units 1 & 3	6.24%	12,631,024	788,176	5.07	39,961	4.95	39,054	0.12	907
312.10	BOILER PLANT EQUIPMENT - UNIT TRAIN	Units 1 & 3	6.24%	4,654,876	290,464	3.13	9,092	3.15	9,160	(0.02)	(68)
314.00	TURBOGENERATOR UNITS	Units 1 & 3	6.24%	3,926,018	244,984	0.48	1,176	0.47	1,150	0.01	26
315.00	ACCESSORY ELECTRIC EQUIPMENT	Units 1 & 3	6.24%	5,291,116	330,166	8.00	26,413	7.52	24,839	0.48	1,575
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT	Units 1 & 3	6.24%	3,146,044	196,313	3.48	6,832	3.67	7,213	(0.19)	(382)
		Total Units 1 & 3		43,341,571	2,704,514		116,880		112,636		4,245
311.00	STRUCTURES AND IMPROVEMENTS	Unit 3	6.24%	240,947	15,035	6.76	1,016	7.18	1,080	(0.42)	(64)
312.00	BOILER PLANT EQUIPMENT	Unit 3	6.24%	19,792,769	1,235,069	3.83	47,303	3.38	41,714	0.45	5,589
312.50	BOILER PLANT EQUIPMENT - COMBUSTION INITIATIVE	Unit 3	6.24%	52,713,582	3,289,327	6.20	203,938	6.23	204,933	(0.03)	(994)
314.00	TURBOGENERATOR UNITS	Unit 3	6.24%	10,034,834	626,174	3.31	20,726	3.23	20,237	0.08	490
315.00	ACCESSORY ELECTRIC EQUIPMENT	Unit 3	6.24%	0	0	-	-	7.98	-	(7.98)	-
		Total Unit 3		82,782,131	5,165,605		272,984		267,964		5,021
		Total Sutherland		137,633,060	8,588,303		486,044		451,397		34,647
	TOTAL STEAM PRODUCTION PLANT			**1,409,788,434**	**87,970,798**		**3,257,542**		**3,300,441**		**(42,899)**
	OTHER PRODUCTION PLANT										
	BURLINGTON CT										
344.00	GENERATORS	Unit 1	6.24%	99,021	6,179	2.45	151	2.36	146	0.09	5
		Total Unit 1		99,021	6,179		151		146		5
343.00	ENGINES	Unit 2	6.24%	37,241	2,324	13.27	308	12.32	286	0.95	22
344.00	GENERATORS	Unit 2	6.24%	257,303	16,056	2.65	425	2.36	379	0.29	47
		Total Unit 2		294,543	18,379		734		665		69
344.00	GENERATORS	Unit 3	6.24%	45,558	2,843	2.45	70	2.36	67	0.09	3
		Total Unit 3		45,558	2,843		70		67		3
344.00	GENERATORS	Unit 4	6.24%	10,429	651	2.45	16	2.36	15	0.09	1
		Total Unit 4		10,429	651		16		15		1
341.00	STRUCTURES AND IMPROVEMENTS	Units 1 - 4	6.24%	33,540	2,093	4.76	100	4.75	99	0.01	0
342.00	OIL SYSTEM	Units 1 - 4	6.24%	2,200,774	137,328	6.72	9,228	4.58	6,291	2.14	2,937
343.00	ENGINES	Units 1 - 4	6.24%	395,138	24,657	7.08	1,746	7.09	1,749	(0.01)	(3)
344.00	GENERATORS	Units 1 - 4	6.24%	14,001,047	873,665	6.49	56,701	6.39	55,846	0.10	855
345.00	ACCESSORY ELECTRIC EQUIPMENT	Units 1 - 4	6.24%	342,337	21,362	3.89	831	3.69	789	0.20	42
346.00	MISCELLANEOUS PLANT EQUIPMENT	Units 1 - 4	6.24%	26,015	1,623	2.44	40	2.33	38	0.11	2
		Total Units 1 - 4		16,998,852	1,060,728		68,645		64,813		3,832
		Total Burlington CT		**17,448,403**	**1,088,780**		69,616		65,706		3,910
	CENTERVILLE DIESEL										
342.00	OIL SYSTEM		6.24%	9,693	605	3.77	23	3.27	20	0.50	3
343.00	ENGINES		6.24%	59,232	3,696	6.48	240	5.40	200	1.08	40
344.00	GENERATORS		6.24%	410,858	25,638	19.50	4,999	17.65	4,524	1.85	475
345.00	ACCESSORY ELECTRIC EQUIPMENT		6.24%	133,544	8,333	10.01	834	9.46	788	0.55	46
346.00	MISCELLANEOUS PLANT EQUIPMENT		6.24%	1,393	87	4.16	4	2.58	2	1.58	1
				614,721	38,359		6,099		5,534		565

INTERSTATE POWER AND LIGHT COMPANY
COMPARISON OF DEPRECIATION EXPENSE CALCULATED USING CURRENT AND PROPOSED DEPRECIATION RATES

ACCOUNT	LOCATION/ACCOUNT NAME	UNIT	ALLOCATOR (a)	PLANT BALANCE 12/31/2012 (b)	MINNESOTA PORTION OF PLANT BALANCE (c) (a)*(b)	MINNESOTA PORTION OF PROPOSED DEPRECIATION BASE RATE % (d)	MINNESOTA PORTION OF PROPOSED DEPRECIATION AMOUNT (e) ((c)*(d))/100	MINNESOTA PORTION OF CURRENT DEPRECIATION BASE RATE % (f)	MINNESOTA PORTION OF CURRENT DEPRECIATION AMOUNT (g) ((c)*(f))/100	Expense Increase (Decrease) BASE RATE CHANGE (h) (d)-(f)	Expense Increase (Decrease) AMOUNT (i) (e)-(g)
	CENTERVILLE CT										
341.00	STRUCTURES AND IMPROVEMENTS	Unit 1	6.24%	4,586	286	5.67	16	6.02	17	(0.35)	(1)
343.00	ENGINES	Unit 1	6.24%	329,020	20,531	13.08	2,685	13.35	2,742	(0.27)	(56)
344.00	GENERATORS	Unit 1	6.24%	1,340,013	83,617	8.19	-	-	0	8.19	-
		Total Unit 1		1,673,619	104,434		2,702		2,759		(57)
341.00	STRUCTURES AND IMPROVEMENTS	Unit 2	6.24%	84,268	5,258	19.16	1,008	16.85	886	2.31	121
344.00	GENERATORS	Unit 2	6.24%	1,100,562	68,675	19.26	-	-	-	19.26	-
345.00	ACCESSORY ELECTRIC EQUIPMENT	Unit 2	6.24%	61,022	3,808	27.79	1,058	38.86	1,480	(11.07)	(421)
		Total Unit 2		1,245,852	77,741		2,066		2,366		(300)
341.00	STRUCTURES AND IMPROVEMENTS	Units 1 & 2	6.24%	173,703	10,839	9.69	1,050	6.46	700	3.23	350
342.00	OIL SYSTEM	Units 1 & 2	6.24%	195,729	12,213	4.84	591	3.22	394	1.62	198
343.00	ENGINES	Units 1 & 2	6.24%	939	59	16.51	10	15.44	9	1.07	1
344.00	GENERATORS	Units 1 & 2	6.24%	1,515,941	94,595	5.02	4,749	12.09	11,432	(7.07)	(6,684)
345.00	ACCESSORY ELECTRIC EQUIPMENT	Units 1 & 2	6.24%	929,464	57,999	23.17	13,438	26.54	15,393	(3.37)	(1,955)
346.00	MISCELLANEOUS PLANT EQUIPMENT	Units 1 & 2	6.24%	108,176	6,750	5.88	397	4.81	325	1.07	72
		Total Units 1 & 2		2,923,952	182,455		20,235		28,253		(8,018)
		Total Centerville CT		5,843,422	364,630		25,002		33,378		(8,375)
	DUBUQUE DIESEL										
341.00	STRUCTURES AND IMPROVEMENTS		6.24%	19,753	1,233	3.59	44	0.51	6	3.08	38
342.00	OIL SYSTEM		6.24%	39,471	2,463	6.98	172	1.49	37	5.49	135
343.00	ENGINES		6.24%	191,404	11,944	10.64	1,271	1.60	191	9.04	1,080
344.00	GENERATORS		6.24%	78,320	4,887	13.33	651	2.48	121	10.85	530
345.00	ACCESSORY ELECTRIC EQUIPMENT		6.24%	92,036	5,743	1.88	108	0.27	16	1.61	92
346.00	MISCELLANEOUS PLANT EQUIPMENT		6.24%	21,009	1,311	4.18	55	1.05	14	3.13	41
				441,993	27,580		2,301		385		1,917
	DUBUQUE UNIT 3 & 4										
341.00	STRUCTURES AND IMPROVEMENTS		6.24%	4,233,766	264,187	5.20	13,738	14.76	38,994	(9.56)	(25,257)
343.00	ENGINES		6.24%	16,374,314	1,021,757	8.40	85,828	10.95	111,839	(2.55)	(26,011)
344.00	GENERATORS		6.24%	4,793,254	299,099	6.73	20,129	2.32	6,935	4.41	13,195
345.00	ACCESSORY ELECTRIC EQUIPMENT		6.24%	5,375,593	335,437	31.99	107,306	22.16	74,338	9.83	32,968
346.00	MISCELLANEOUS PLANT EQUIPMENT		6.24%	1,865,223	116,390	8.97	10,440	14.10	16,406	(5.13)	(5,966)
				32,642,150	2,036,870		237,441		248,513		(11,072)
	EMERY										
341.00	STRUCTURES AND IMPROVEMENTS		6.24%	58,855,000	3,672,552	4.28	157,185	4.27	156,850	0.01	335
342.00	OIL SYSTEM		6.24%	17,012,068	1,061,553	4.41	46,814	4.41	46,865	(0.00)	(51)
343.00	ENGINES		6.24%	14,717,758	918,388	4.60	42,246	4.60	42,220	0.00	25
344.00	GENERATORS		6.24%	295,588,004	18,444,691	4.47	824,476	4.39	810,084	0.08	14,394
345.00	ACCESSORY ELECTRIC EQUIPMENT		6.24%	22,505,828	1,404,364	4.41	61,932	4.42	62,116	(0.01)	(183)
346.00	MISCELLANEOUS PLANT EQUIPMENT		6.24%	1,192,579	74,417	4.33	3,222	4.35	3,237	(0.02)	(15)
				409,871,237	25,575,965		1,135,878		1,121,372		14,506
	GRINNELL COMBUSTION TURBINE										
341.00	STRUCTURES AND IMPROVEMENTS		6.24%	235,893	14,720	4.13	608	4.09	601	0.04	6
342.00	OIL SYSTEM		6.24%	120,808	7,538	5.03	379	4.83	364	0.20	15
343.00	ENGINES		6.24%	13,032	813	10.32	84	9.94	81	0.38	3
344.00	GENERATORS		6.24%	4,441,563	277,154	7.29	20,204	6.95	19,249	0.34	956
345.00	ACCESSORY ELECTRIC EQUIPMENT		6.24%	1,187,866	74,123	10.55	7,820	7.07	5,241	3.48	2,579
346.00	MISCELLANEOUS PLANT EQUIPMENT		6.24%	15,310	955	6.94	66	3.02	29	3.92	37
				6,014,472	375,303		29,162		25,565		3,597
	HILLS										
342.00	OIL SYSTEMS		6.24%	97,782	6,102	-	-	-	-	-	-
343.00	ENGINES		6.24%	230,721	14,397	1.36	196	1.10	158	0.26	37
344.00	GENERATORS		6.24%	207,874	12,971	0.48	62	0.83	108	(0.35)	(46)
345.00	ACCESSORY ELECTRIC EQUIPMENT		6.24%	324,856	20,271	1.40	284	1.14	230	0.26	53
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT		6.24%	15,085	941	-	-	-	-	-	-
				876,318	54,682		542		497		45
	LANSING										
341.00	STRUCTURES AND IMPROVEMENTS		6.24%	15,026	938	-	-	3.24	30	(3.24)	(30)
342.00	OIL SYSTEM		6.24%	2,018	126	-	-	9.91	12	(9.91)	(12)
343.00	ENGINES		6.24%	173,504	10,827	-	-	9.18	994	(9.18)	(994)
344.00	GENERATORS		6.24%	28,201	1,760	-	-	15.26	269	(15.26)	(269)
345.00	ACCESSORY ELECTRIC EQUIPMENT		6.24%	38,139	2,380	-	-	1.93	46	(1.93)	(46)
				256,888	16,030		-		1,351		(1,351)
	LIME CREEK										
341.00	STRUCTURES AND IMPROVEMENTS		6.24%	2,171,344	135,492	1.54	2,087	1.55	2,102	(0.01)	(16)
342.00	OIL SYSTEM		6.24%	767,931	47,919	1.69	810	1.64	785	0.05	25
343.00	ENGINES		6.24%	16,081,555	1,003,489	1.74	17,461	1.75	17,576	(0.01)	(115)
344.00	GENERATORS		6.24%	4,302,032	268,447	1.96	5,262	1.95	5,238	0.01	24
345.00	ACCESSORY ELECTRIC EQUIPMENT		6.24%	1,834,548	114,476	2.00	2,290	1.88	2,150	0.12	139
346.00	MISCELLANEOUS PLANT EQUIPMENT		6.24%	115,731	7,222	3.66	264	4.22	305	(0.56)	(41)
				25,273,140	1,577,044		28,172		28,155		17
	MARSHALLTOWN DIESEL										
341.00	STRUCTURES AND IMPROVEMENTS		6.24%	248,927	15,533	-	-	-	-	-	-
342.00	OIL SYSTEM		6.24%	88,857	5,545	-	-	-	-	-	-
343.00	ENGINES		6.24%	727,300	45,383	-	-	-	-	-	-
345.00	ACCESSORY ELECTRIC EQUIPMENT		6.24%	107,992	6,739	-	-	-	-	-	-
346.00	MISCELLANEOUS PLANT EQUIPMENT		6.24%	7,782	486	-	-	-	-	-	-
				1,180,858	73,686		-		-		-
	RED CEDAR										
341.00	STRUCTURES AND IMPROVEMENTS		6.24%	95,587	5,965	5.89	351	5.87	350	0.02	1
344.00	GENERATORS		6.24%	13,881,382	866,198	4.27	36,987	4.28	37,052	(0.01)	(65)
346.00	MISCELLANEOUS PLANT EQUIPMENT		6.24%	103,575	6,463	4.86	314	4.87	315	(0.01)	(1)
				14,080,544	878,626		37,652		37,717		(65)

INTERSTATE POWER AND LIGHT COMPANY
COMPARISON OF DEPRECIATION EXPENSE CALCULATED USING CURRENT
AND PROPOSED DEPRECIATION RATES

ACCOUNT	LOCATION/ACCOUNT NAME	UNIT	ALLOCATOR (a)	PLANT BALANCE 12/31/2012 (b)	MINNESOTA PORTION OF PLANT BALANCE (c) (a)*(b)	MINNESOTA PORTION OF PROPOSED DEPRECIATION: BASE RATE % (d)	MINNESOTA PORTION OF PROPOSED DEPRECIATION: AMOUNT (e) ((c)*(d))/100	MINNESOTA PORTION OF CURRENT DEPRECIATION: BASE RATE % (f)	MINNESOTA PORTION OF CURRENT DEPRECIATION: AMOUNT (g) ((c)*(f))/100	Expense Increase (Decrease): BASE RATE CHANGE (h) (d)-(f)	Expense Increase (Decrease): AMOUNT (i) (e)-(g)
	SUTHERLAND CT										
344.00	GENERATORS	Unit 1	6.24%	7,314,711	456,438	3.35	15,291	3.64	16,608	(0.29)	(1,317)
		Total Unit 1		7,314,711	456,438		15,291		16,608		(1,317)
344.00	GENERATORS	Unit 2	6.24%	7,306,759	455,942	3.21	14,636	3.52	16,047	(0.31)	(1,412)
		Total Unit 2		7,306,759	455,942		14,636		16,047		(1,412)
344.00	GENERATORS	Unit 3	6.24%	9,433,757	588,666	9.06	53,333	8.34	49,071	0.72	4,262
		Total Unit 3		9,433,757	588,666		53,333		49,071		4,262
341.00	STRUCTURES AND IMPROVEMENTS	Units 1 - 3	6.24%	188,716	11,776	2.04	240	1.90	224	0.14	17
342.00	OIL SYSTEM	Units 1 - 3	6.24%	720,969	44,988	13.16	5,920	12.27	5,521	0.89	400
344.00	GENERATORS	Units 1 - 3	6.24%	251,712	15,707	9.16	1,439	8.38	1,317	0.78	122
345.00	ACCESSORY ELECTRIC EQUIPMENT	Units 1 - 3	6.24%	424,044	26,460	14.80	3,916	14.22	3,762	0.58	155
		Total Units 1 - 3		1,585,441	98,932		11,516		10,823		693
		Total Sutherland CT		25,640,667	1,599,978		94,775		92,549		2,226
	WHISPERING WILLOW										
341.00	STRUCTURES AND IMPROVEMENTS		6.24%	58,260,314	3,635,444	4.13	150,144	4.12	149,760	0.01	384
344.00	GENERATORS		6.24%	319,317,181	19,925,392	4.21	838,859	4.21	838,858	0.00	1
345.00	ACCESSORY ELECTRIC EQUIPMENT		6.24%	26,566,968	1,657,779	4.38	72,611	4.37	72,504	0.01	107
346.00	MISCELLANEOUS PLANT EQUIPMENT		6.24%	320,287	19,986	3.95	789	4.29	856	(0.34)	(67)
				404,464,750	25,238,600		1,062,403		1,061,978		425
	TOTAL OTHER PRODUCTION PLANT			944,649,562	56,909,262		2,729,044		2,722,701		6,344
	IOWA DISTRIBUTION PLANT										
361.00	STRUCTURES AND IMPROVEMENTS		0.00%	31,546,657	0	N/A	-	N/A	-	N/A	-
362.00	STATION EQUIPMENT		0.00%	284,872,305	0	N/A	-	N/A	-	N/A	-
362.40	STATION EQUIPMENT - SYSTEM CONTROL CENTER		0.00%	7,936,905	0	N/A	-	N/A	-	N/A	-
364.00	POLES, TOWERS AND FIXTURES		0.00%	379,551,093	0	N/A	-	N/A	-	N/A	-
365.00	OVERHEAD CONDUCTORS AND DEVICES		0.00%	449,551,209	0	N/A	-	N/A	-	N/A	-
366.00	UNDERGROUND CONDUIT		0.00%	58,546,414	0	N/A	-	N/A	-	N/A	-
367.00	UNDERGROUND CONDUCTORS AND DEVICES		0.00%	244,524,634	0	N/A	-	N/A	-	N/A	-
368.00	LINE TRANSFORMERS		0.00%	286,814,291	0	N/A	-	N/A	-	N/A	-
369.00	SERVICES		0.00%	126,137,699	0	N/A	-	N/A	-	N/A	-
370.00	METERS		0.00%	86,155,080	0	N/A	-	N/A	-	N/A	-
373.00	STREET LIGHTING AND SIGNAL SYSTEMS		0.00%	59,051,010	0	N/A	-	N/A	-	N/A	-
	TOTAL IOWA DISTRIBUTION PLANT			2,014,687,297	0		-		-		-
	MINNESOTA DISTRIBUTION PLANT										
361.00	STRUCTURES AND IMPROVEMENTS		100.00%	651,704	651,704	1.80	11,731	1.79	11,665	0.01	65
362.00	STATION EQUIPMENT		100.00%	23,655,287	23,655,287	3.27	773,528	3.13	740,410	0.14	33,117
364.00	POLES, TOWERS AND FIXTURES		100.00%	36,174,283	36,174,283	2.34	846,478	2.25	813,921	0.09	32,557
365.00	OVERHEAD CONDUCTORS AND DEVICES		100.00%	38,075,042	38,075,042	3.11	1,184,134	3.10	1,180,326	0.01	3,808
366.00	UNDERGROUND CONDUIT		100.00%	956,606	956,606	2.66	25,446	2.67	25,541	(0.01)	(96)
367.00	UNDERGROUND CONDUCTORS AND DEVICES		100.00%	16,450,764	16,450,764	3.01	495,168	3.01	495,168	-	-
368.00	LINE TRANSFORMERS		100.00%	16,078,599	16,078,599	2.08	334,435	2.03	326,396	0.05	8,039
369.00	SERVICES		100.00%	9,624,775	9,624,775	3.69	355,154	3.66	352,267	0.03	2,887
370.00	METERS		100.00%	2,966,769	2,966,769	7.51	222,804	7.11	210,937	0.40	11,867
373.00	STREET LIGHTING AND SIGNAL SYSTEMS		100.00%	4,346,966	4,346,966	5.12	222,565	5.00	217,348	0.12	5,216
	TOTAL MINNESOTA DISTRIBUTION PLANT			148,980,794	148,980,794		4,471,442		4,373,981		97,461
	TOTAL DISTRIBUTION PLANT			2,163,668,091	148,980,794		4,471,442		4,373,981		97,461
	IOWA GENERAL PLANT										
390.00	STRUCTURES AND IMPROVEMENTS		6.55%	39,336,120	2,576,516	2.51	64,671	2.43	62,656	0.08	2,015
391.00	OFFICE FURNITURE AND EQUIPMENT		6.55%	3,995,801	261,725	4.79	12,537	4.90	12,823	(0.11)	(287)
391.40	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS		6.55%	1,628,649	106,677	28.69	30,605	20.87	22,259	7.82	8,347
392.00	TRANSPORTATION EQUIPMENT		6.55%	56,480,673	3,699,484	4.03	149,089	4.07	150,669	(0.04)	(1,580)
393.00	STORES EQUIPMENT		6.55%	117,495	7,696	9.40	723	8.63	664	0.77	59
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		6.55%	29,351,002	1,922,491	4.05	77,861	4.06	77,983	(0.01)	(123)
395.00	LABORATORY EQUIPMENT		6.55%	159,114	10,422	43.79	4,564	30.13	3,140	13.66	1,424
396.00	POWER OPERATED EQUIPMENT		6.55%	4,571,641	299,442	4.48	13,415	4.60	13,781	(0.12)	(366)
397.00	COMMUNICATION EQUIPMENT										
	ELECTRONIC		6.55%	15,032,254	984,613	11.20	110,277	11.27	110,966	(0.07)	(689)
	TOWER/BUILDING		6.55%	8,513,236	557,617	8.21	45,780	9.27	51,681	(1.06)	(5,901)
	TOTAL IOWA GENERAL PLANT			159,185,987	10,426,682		509,522		506,623		2,899
	MINNESOTA GENERAL PLANT										
390.00	STRUCTURES AND IMPROVEMENTS		6.55%	4,007,634	262,500	2.07	5,434	2.01	5,276	0.06	158
390.10	LEASEHOLD IMPROVEMENTS		6.55%	0	0	-	-	18.38	0	(18.38)	-
391.10	OFFICE FURNITURE AND EQUIPMENT - EXCEPT COMPUTERS		6.55%	181,076	11,860	4.75	563	4.72	560	0.03	4
391.40	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS		6.55%	36,578	2,396	12.90	309	14.34	344	(1.44)	(35)
392.00	TRANSPORTATION EQUIPMENT - TRUCKS, TRAILERS AND VANS		6.55%	8,035,158	526,303	7.09	37,315	7.58	39,894	(0.49)	(2,579)
393.00	STORES EQUIPMENT		6.55%	16,420	1,075	3.75	40	3.75	40	-	-
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		6.55%	972,128	63,674	3.84	2,445	3.91	2,490	(0.07)	(45)
395.00	LABORATORY EQUIPMENT		6.55%	35,684	2,337	7.20	168	6.87	161	0.33	8
396.00	POWER OPERATED EQUIPMENT		6.55%	1,410,598	92,394	5.46	5,045	6.38	5,895	(0.92)	(850)
397.00	COMMUNICATION EQUIPMENT									-	
	ELECTRONIC		6.55%	1,107,115	72,516	5.40	3,916	5.68	4,119	(0.28)	(203)
	TOWER/BUILDING		6.55%	2,796,927	183,199	3.67	6,723	3.68	6,742	(0.01)	(18)
	TOTAL MINNESOTA GENERAL PLANT			18,599,318.55	1,218,255		61,959		65,519		(3,561)
	TOTAL GENERAL PLANT			177,785,305.08	11,644,937		571,481		572,142		(661)
	TOTAL ELECTRIC PLANT			4,695,891,392	305,505,792		11,029,509		10,969,265		60,245

INTERSTATE POWER AND LIGHT COMPANY
COMPARISON OF DEPRECIATION EXPENSE CALCULATED USING CURRENT AND PROPOSED DEPRECIATION RATES

				PLANT BALANCE	MINNESOTA PORTION OF PLANT BALANCE	MINNESOTA PORTION OF PROPOSED DEPRECIATION		MINNESOTA PORTION OF CURRENT DEPRECIATION		Expense Increase (Decrease)	
ACCOUNT	LOCATION/ACCOUNT NAME	UNIT	ALLOCATOR	12/31/2012		BASE RATE %	AMOUNT	BASE RATE %	AMOUNT	BASE RATE CHANGE	AMOUNT
			(a)	(b)	(c) (a)*(b)	(d)	(e) ((c)*(d))/100	(f)	(g) ((c)*(f))/100	(h) (d)-(f)	(i) (e)-(g)
	GAS PLANT										
	IOWATRANSMISSION PLANT										
366.00	STRUCTURES AND IMPROVEMENTS		0.00%	319,442	0	N/A	-	N/A	-	N/A	-
367.00	MAINS		0.00%	41,071,858	0	N/A	-	N/A	-	N/A	-
369.00	MEASURING AND REGULATING STATION EQUIPMENT		0.00%	4,999,690	0	N/A	-	N/A	-	N/A	-
	TOTAL IOWA TRANSMISSION PLANT			46,390,990	0		-		-		-
	IOWA DISTRIBUTION PLANT										
375.00	STRUCTURES AND IMPROVEMENTS		0.00%	757,821	0	N/A	-	N/A	-	N/A	-
376.00	MAINS		0.00%	167,358,948	0	N/A	-	N/A	-	N/A	-
378.00	MEASURING AND REGULATING STATION EQUIPMENT		0.00%	9,994,158	0	N/A	-	N/A	-	N/A	-
379.00	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE		0.00%	4,301,091	0	N/A	-	N/A	-	N/A	-
380.00	SERVICES		0.00%	91,232,571	0	N/A	-	N/A	-	N/A	-
381.00	METERS		0.00%	34,960,141	0	N/A	-	N/A	-	N/A	-
382.00	METER INSTALLATIONS		0.00%	27,574,131	0	N/A	-	N/A	-	N/A	-
383.00	HOUSE REGULATORS		0.00%	22,134,119	0	N/A	-	N/A	-	N/A	-
385.00	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT		0.00%	2,551,546	0	N/A	-	N/A	-	N/A	-
387.00	OTHER EQUIPMENT		0.00%	13,449	0	N/A	-	N/A	-	N/A	-
	TOTAL IOWA DISTRIBUTION PLANT			360,877,974	0		-		-		-
	MINNESOTA DISTRIBUTION PLANT										
375.00	STRUCTURES AND IMPROVEMENTS		100.00%	3,470	3,470	1.84	64	3.42	119	(1.58)	(55)
376.00	MAINS		100.00%	8,062,945	8,062,945	2.10	169,322	2.10	169,322	-	-
378.00	MEASURING AND REGULATING EQUIPMENT - GENERAL		100.00%	128,113	128,113	4.86	6,226	4.76	6,098	0.10	128
379.00	MEASURING AND REGULATING EQUIPMENT - CITY GATE		100.00%	442,848	442,848	5.47	24,224	4.92	21,788	0.55	2,436
380.10	SERVICES		100.00%	4,346,549	4,346,549	5.85	254,273	5.70	247,753	0.15	6,520
381.00	METERS		100.00%	2,036,990	2,036,990	6.77	137,904	7.25	147,682	(0.48)	(9,778)
382.00	METER INSTALLATIONS		100.00%	1,618,277		5.31		5.70			
383.00	HOUSE REGULATORS		100.00%	413,729	413,729	6.60	27,306	6.82	28,216	(0.22)	(910)
385.00	IND. MEASURING AND REGULATING STATION EQUIPMENT		100.00%	38,782	38,782	0.78	303	0.87	337	(0.09)	(35)
	TOTAL MINNESOTA DISTRIBUTION PLANT			17,091,702	15,473,426		619,622		621,316		(1,694)
	TOTAL DISTRIBUTION PLANT			377,969,676	15,473,426		619,622		621,316		(1,694)
	IOWA GENERAL PLANT										
390.00	STRUCTURES AND IMPROVEMENTS		4.02%	1,214,372	48,818	3.12	1,523	3.05	1,488	0.07	35
391.00	OFFICE FURNITURE AND EQUIPMENT		4.02%	222,728	8,954	5.01	449	5.10	456	-0.09	(8)
391.40	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS		4.02%	0	0	-	-	74.25	0	-74.25	-
392.00	TRANSPORTATION EQUIPMENT		4.02%	3,475,805	139,727	6.45	9,012	6.65	9,294	-0.20	(282)
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		4.02%	7,357,005	295,752	4.07	12,037	4.09	12,091	-0.02	(54)
395.00	LABORATORY EQUIPMENT		4.02%	9,097	366	8.22	30	6.16	23	2.06	8
396.00	POWER OPERATED EQUIPMENT		4.02%	1,676,692	67,403	6.26	4,219	6.33	4,266	-0.07	(46)
397.00	COMMUNICATION EQUIPMENT		4.02%	714,290	28,714	2.82	810	7.40	2,125	-4.58	(1,315)
	TOTAL IOWA GENERAL PLANT			14,669,990	589,734		28,080		29,743		(1,663)
	MINNESOTA GENERAL PLANT										
390.00	STRUCTURES AND IMPROVEMENTS		4.02%	259,524	10,433	3.61	377	3.62	378	-0.01	(1)
392.20	TRANSPORTATION EQUIPMENT - TRUCKS		4.02%	23,838	958	11.20	107	11.44	110	-0.24	(2)
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		4.02%	122,323	4,917	5.54	272	6.60	325	-1.06	(52)
395.00	LABORATORY EQUIPMENT		4.02%	4,911	197	17.96	35	13.50	27	4.46	9
	TOTAL MINNESOTA GENERAL PLANT			410,595	16,506		792		838		(47)
	TOTAL GENERAL PLANT			15,080,585	606,240		28,872		30,582		(1,709)
	TOTAL GAS PLANT			439,441,252	589,734		648,494		651,897		(3,403)
	COMMON PLANT										
	IOWA COMMON PLANT										
390.00	STRUCTURES AND IMPROVEMENTS		6.18%	94,523,520	5,841,554	1.84	107,485	1.78	103,756	0.06	3,728
391.00	OFFICE FURNITURE AND EQUIPMENT		6.18%	15,537,213	960,200	2.54	24,389	2.29	21,956	0.25	2,433
391.40	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS		6.18%	9,629,871	595,126	21.94	130,571	19.87	118,262	2.07	12,309
392.00	TRANSPORTATION EQUIPMENT		6.18%	24,881,461	1,537,674	6.00	92,260	6.28	96,530	-0.28	(4,270)
393.00	STORES EQUIPMENT		6.18%	71,696	4,431	1.45	-	-	-	1.45	-
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		6.18%	5,070,905	313,382	3.24	10,154	3.15	9,869	0.09	285
396.00	POWER OPERATED EQUIPMENT		6.18%	5,854,043	361,780	3.34	12,083	3.25	11,754	0.09	330
397.00	COMMUNICATION EQUIPMENT										
	ELECTRONIC		6.18%	25,644,190	1,584,811	9.13	144,693	9.13	144,691	0.00	3
	TOWER/BUILDING		6.18%	6,249,504	386,219	4.19	16,183	3.96	15,281	0.23	901
397.40	COMMUNICATION EQUIPMENT - IDEN										
	ELECTRONIC		6.18%	9,760,057	603,172	15.94	96,146	16.57	99,923	-0.63	(3,778)
	TOWER/BUILDING		6.18%	1,312,295	81,100	3.71	3,009	5.17	4,195	-1.46	(1,186)
398.00	MISCELLANEOUS EQUIPMENT		6.18%	96,870	5,987	5.51	330	5.52	331	-0.01	(1)
	TOTAL IOWA COMMON PLANT			198,631,625	12,275,434		637,302		626,549		10,753

INTERSTATE POWER AND LIGHT COMPANY
COMPARISON OF DEPRECIATION EXPENSE CALCULATED USING CURRENT
AND PROPOSED DEPRECIATION RATES

ACCOUNT	LOCATION/ACCOUNT NAME	UNIT	ALLOCATOR (a)	PLANT BALANCE 12/31/2012 (b)	MINNESOTA PORTION OF PLANT BALANCE (c) (a)*(b)	MINNESOTA PORTION OF PROPOSED DEPRECIATION BASE RATE % (d)	MINNESOTA PORTION OF PROPOSED DEPRECIATION AMOUNT (e) ((c)*(d))/100	MINNESOTA PORTION OF CURRENT DEPRECIATION BASE RATE % (f)	MINNESOTA PORTION OF CURRENT DEPRECIATION AMOUNT (g) ((c)*(f))/100	Expense Increase (Decrease) BASE RATE CHANGE (h) (d)-(f)	Expense Increase (Decrease) AMOUNT (i) (e)-(g)
	MINNESOTA COMMON PLANT										
390.00	STRUCTURES AND IMPROVEMENTS		6.18%	271,833	16,805	2.13	358	2.13	359	(0.00)	(1)
391.00	OFFICE FURNITURE AND EQUIPMENT										
	EXCEPT COMPUTERS		6.18%	41,676	2,576	4.87	125	4.87	125	0.00	0
	COMPUTERS		6.18%	3,714	230	25.42	58	8.15	21	16.27	37
392.00	TRANSPORTATION EQUIPMENT										
	TRUCKS, TRAILERS AND VANS		6.18%	3,267,870	201,954	6.63	13,390	7.19	14,521	-0.56	(1,131)
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT		6.18%	81,329	5,026	3.78	190	3.78	190	0.00	-
396.00	POWER OPERATED EQUIPMENT		6.18%	595,372	36,794	6.48	2,384	7.15	2,631	-0.67	(247)
397.00	COMMUNICATION EQUIPMENT										
	ELECTRONIC		6.18%	909,778	56,224	9.18	5,161	7.98	4,487	1.20	675
	TOWER/BUILDING		6.18%	246,071	15,207	2.69	409	2.56	389	0.13	20
397.40	COMMUNICATION EQUIPMENT - IDEN										
	ELECTRONIC		6.18%	6,104,539	377,261	12.75	48,101	13.65	51,496	-0.90	(3,395)
	TOWER/BUILDING		6.18%	1,491,164	92,154	3.69	3,400	3.66	3,373	0.03	28
	TOTAL MINNESOTA COMMON PLANT			13,013,448	804,231		73,577		77,591		(4,014)
	TOTAL COMMON PLANT			211,645,073	13,079,665.50		710,879		704,140		6,739
	TOTAL COMPANY			5,346,977,716	319,175,191		12,388,882		12,325,302		63,581

Part 2: Summary of estimated survivor curves, net salvage, original cost, book depreciation reserve and calculated annual depreciation rates as of December 31, 2012

ALLIANT ENERGY - IOWA
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2012

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	ELECTRIC PLANT									
	STEAM PRODUCTION PLANT									
311.00	STRUCTURES AND IMPROVEMENTS									
	Neal Unit 4	100-S2.5	*	(30)	13,106,494.07	11,141,894	5,896,548	218,328	1.67	27.0
	Lansing Unit 4	100-S2.5	*	(30)	27,732,200.81	24,719,271	11,332,590	470,568	1.70	24.1
	Louisa Unit 1	100-S2.5	*	(30)	5,970,493.68	6,329,865	1,431,777	52,919	0.89	27.1
	Clinton Unit 2 (ML KAPP)	100-S2.5	*	(30)	10,521,583.07	9,000,856	4,677,202	407,479	3.87	11.5
	Lansing Unit 3	100-S2.5	*	(30)	1,097,464.48	1,426,704	0	0	-	-
	Lansing Units 3 & 4	100-S2.5	*	(30)	226,357.68	37,064	257,201	10,505	4.64	24.5
	Burlington Station	100-S2.5	*	(30)	12,803,578.40	8,940,036	7,704,616	671,608	5.25	11.5
	Neal Unit 3	100-S2.5	*	(30)	5,078,323.67	4,417,344	2,184,477	98,680	1.94	22.1
	Ottumwa	100-S2.5	*	(30)	45,029,567.92	29,817,732	28,720,706	1,350,720	3.00	21.3
	Prairie Creek Unit 4	100-S2.5	*	(30)	561,370.27	594,567	135,214	6,012	1.07	22.5
	Prairie Creek Units 1 - 4	100-S2.5	*	(30)	26,158,851.91	12,770,140	21,236,367	947,048	3.62	22.4
	Sutherland 3	100-S2.5	*	(30)	240,946.58	125,786	187,445	16,300	6.76	11.5
	Sutherland 1 & 3	100-S2.5	*	(30)	13,692,493.70	11,664,099	6,136,143	534,840	3.91	11.5
	TOTAL ACCOUNT 311 - STRUCTURES AND IMPROVEMENTS				162,219,726.24	120,985,358	89,900,286	4,785,007	2.95	18.8
312.00	BOILER PLANT EQUIPMENT									
	Neal Unit 4	75-R2	*	(20)	58,916,625.42	48,985,954	21,713,997	848,659	1.44	25.6
	Lansing Unit 4	75-R2	*	(20)	292,380,169.40	71,910,754	278,945,449	11,748,135	4.02	23.7
	Louisa Unit 1	75-R2	*	(20)	21,041,271.23	11,355,405	13,894,120	528,687	2.51	26.3
	Clinton Unit 2 (ML KAPP)	75-R2	*	(20)	50,853,247.02	35,813,239	25,210,657	2,227,249	4.38	11.3
	Lansing Unit 3	75-R2	*	(20)	5,326,062.85	6,391,275	0	0	-	-
	Lansing Units 3 & 4	75-R2	*	(20)	3,326,798.24	1,118,971	2,873,187	120,808	3.63	23.8
	Burlington Station	75-R2	*	(20)	59,807,930.67	41,533,736	30,235,781	2,672,192	4.47	11.3
	Neal Unit 3	75-R2	*	(20)	37,697,257.95	29,331,271	15,905,439	739,264	1.96	21.5
	Ottumwa	75-R2	*	(20)	120,486,138.21	60,890,328	83,693,038	4,069,789	3.38	20.6
	Prairie Creek Unit 4	75-R2	*	(20)	58,929,407.87	44,079,372	26,635,917	1,217,667	2.07	21.9
	Prairie Creek Units 1, 2 & 3	75-R2	*	(20)	41,503,505.82	10,785,294	39,018,913	1,781,463	4.29	21.9
	Prairie Creek Units 1 - 4	75-R2	*	(20)	19,657,620.11	3,488,984	20,100,160	914,193	4.65	22.0
	Sutherland 1	75-R2	*	(20)	7,352,175.09	7,655,983	1,166,627	779,006	10.60	1.5
	Sutherland 3	75-R2	*	(20)	19,792,768.59	15,190,597	8,560,725	757,639	3.83	11.3
	Sutherland 1 & 3	75-R2	*	(20)	12,631,023.93	7,886,167	7,271,062	640,287	5.07	11.4
	TOTAL ACCOUNT 312 - BOILER PLANT EQUIPMENT				809,702,002.40	396,417,330	575,225,072	29,045,038	3.59	19.8
312.10	BOILER PLANT EQUIPMENT - UNIT TRAIN									
	Prairie Creek Units 1 - 4	25-R2		20	6,822,659.60	771,600	4,686,528	214,094	3.14	21.9
	Sutherland 1 & 3	25-R2		20	4,654,875.72	659,222	3,064,679	145,729	3.13	21.0
	TOTAL ACCOUNT 312.1 - BOILER PLANT EQUIPMENT - UNIT TRAIN				11,477,535.32	1,430,822	7,751,207	359,823	3.14	21.5

ALLIANT ENERGY - IOWA

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2012

	ACCOUNT	SURVIVOR CURVE		NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)		(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
312.50	BOILER PLANT EQUIPMENT - COMBUSTION INITIATIVE									
	Lansing Unit 4	10-SQ		0	1,462,683.50	1,168,824	293,860	131,454	8.99	2.2
	Clinton Unit 2 (ML KAPP)	10-SQ		0	13,619,219.20	7,906,140	5,713,079	1,357,968	9.97	4.2
	Burlington Station	10-SQ		0	6,208,028.92	5,253,267	954,762	634,492	10.22	1.5
	Ottumwa	10-SQ		0	15,821,340.27	8,280,064	7,541,276	1,591,202	10.06	4.7
	Prairie Creek Unit 4	10-SQ		0	852,949.61	779,519	73,431	48,954	5.74	1.5
	Prairie Creek Units 1, 2 & 3	10-SQ		0	4,504,776.13	1,482,783	3,021,993	460,162	10.21	6.6
	Sutherland 3	75-R2	*	0	52,713,581.73	15,511,126	37,202,456	3,266,256	6.20	11.4
	TOTAL ACCOUNT 312.5 - BOILER PLANT EQUIPMENT - COMBUSTION INITIATIVE				95,182,579.36	40,381,723	54,800,857	7,490,488	7.87	7.3
314.00	TURBOGENERATOR UNITS									
	Neal Unit 4	70-R2.5	*	(10)	13,564,544.21	10,532,679	4,388,320	170,985	1.26	25.7
	Lansing Unit 4	70-R2.5	*	(10)	22,469,321.11	14,945,809	9,770,444	418,270	1.86	23.4
	Louisa Unit 1	70-R2.5	*	(10)	5,028,420.53	2,747,235	2,784,028	106,172	2.11	26.2
	Clinton Unit 2 (ML KAPP)	70-R2.5	*	(10)	19,902,813.79	6,857,981	15,035,114	1,322,569	6.65	11.4
	Lansing Unit 3	70-R2.5	*	(10)	2,439,452.70	2,683,398	0	0	-	-
	Lansing Units 3 & 4	70-R2.5	*	(10)	135,297.31	18,969	129,858	5,418	4.00	24.0
	Burlington Station	70-R2.5	*	(10)	18,759,626.09	7,008,159	13,627,430	1,202,279	6.41	11.3
	Neal Unit 3	70-R2.5	*	(10)	10,481,192.27	8,023,702	3,505,609	162,028	1.55	21.6
	Ottumwa	70-R2.5	*	(10)	32,859,953.67	19,340,228	16,805,721	817,672	2.49	20.6
	Prairie Creek Unit 4	70-R2.5	*	(10)	10,598,132.01	7,500,003	4,157,942	188,119	1.78	22.1
	Prairie Creek Units 1, 2 & 3	70-R2.5	*	(10)	5,636,696.75	2,752,136	3,448,230	157,113	2.79	21.9
	Prairie Creek Units 1 - 4	70-R2.5	*	(10)	1,565,561.64	429,972	1,292,146	58,440	3.73	22.1
	Sutherland 1	70-R2.5	*	(10)	2,255,330.36	2,320,161	160,702	107,657	4.77	1.5
	Sutherland 3	70-R2.5	*	(10)	10,034,834.26	7,261,182	3,777,136	332,116	3.31	11.4
	Sutherland 1 & 3	70-R2.5	*	(10)	3,926,017.98	4,105,171	213,449	18,731	0.48	11.4
	TOTAL ACCOUNT 314 - TURBOGENERATOR UNITS				159,657,194.68	96,526,785	79,096,129	5,067,569	3.17	15.6
315.00	ACCESSORY ELECTRIC EQUIPMENT									
	Neal Unit 4	70-R3	*	(5)	9,546,268.44	7,748,383	2,275,199	89,094	0.93	25.5
	Lansing Unit 4	70-R3	*	(5)	9,172,258.88	7,542,491	2,088,381	90,752	0.99	23.0
	Louisa Unit 1	70-R3	*	(5)	2,646,484.79	1,765,523	1,013,286	38,880	1.47	26.1
	Clinton Unit 2 (ML KAPP)	70-R3	*	(5)	5,348,773.38	4,165,248	1,450,964	127,387	2.38	11.4
	Lansing Unit 3	70-R3	*	(5)	632,913.85	664,560	0	0	-	-
	Lansing Units 3 & 4	70-R3	*	(5)	1,569,394.81	976,901	670,964	29,204	1.86	23.0
	Burlington Station	70-R3	*	(5)	7,629,894.00	1,799,966	6,211,423	544,074	7.13	11.4
	Neal Unit 3	70-R3	*	(5)	5,559,532.83	2,687,908	3,149,601	143,911	2.59	21.9
	Ottumwa	70-R3	*	(5)	18,730,393.82	10,884,794	8,782,120	426,427	2.28	20.6
	Prairie Creek Unit 4	70-R3	*	(5)	6,002,998.45	5,164,181	1,138,967	51,075	0.85	22.3
	Prairie Creek Units 1, 2 & 3	70-R3	*	(5)	10,773,196.44	3,696,700	7,615,156	341,957	3.17	22.3
	Prairie Creek Units 1 - 4	70-R3	*	(5)	29,839,737.50	5,958,996	25,372,728	1,137,979	3.81	22.3
	Sutherland 1	70-R3	*	(5)	1,901,851.94	1,015,364	981,581	654,387	34.41	1.5
	Sutherland 1 & 3	70-R3	*	(5)	5,291,115.67	846,352	4,709,319	423,345	8.00	11.1
	TOTAL ACCOUNT 315 - ACCESSORY ELECTRIC EQUIPMENT				114,644,814.80	54,917,367	65,459,689	4,098,472	3.57	16.0

ALLIANT ENERGY - IOWA

SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2012

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	Neal Unit 4	60-R2	*	(5)	1,175,429.09	844,112	390,089	15,567	1.32	25.1
	Lansing Unit 4	60-R2	*	(5)	3,896,026.55	2,229,925	1,860,903	80,421	2.06	23.1
	Louisa Unit 1	60-R2	*	(5)	169,697.07	70,439	107,743	4,182	2.46	25.8
	Clinton Unit 2 (ML KAPP)	60-R2	*	(5)	4,168,714.05	2,042,807	2,334,343	206,535	4.95	11.3
	Lansing Unit 3	60-R2	*	(5)	223,320.94	234,487	0	0	-	-
	Lansing Units 3 & 4	60-R2	*	(5)	2,472,942.03	560,065	2,036,524	86,812	3.51	23.5
	Burlington Station	60-R2	*	(5)	4,328,129.10	2,725,201	1,819,335	161,841	3.74	11.2
	Neal Unit 3	60-R2	*	(5)	196,174.44	166,749	39,234	1,817	0.93	21.6
	Ottumwa	60-R2	*	(5)	3,490,761.81	1,692,074	1,973,226	97,473	2.79	20.2
	Prairie Creek Unit 4	60-R2	*	(5)	1,158,941.52	1,133,233	83,656	3,851	0.33	21.7
	Prairie Creek Units 1, 2 & 3	60-R2	*	(5)	461,445.38	401,802	82,716	3,930	0.85	21.0
	Prairie Creek Units 1 - 4	60-R2	*	(5)	6,116,996.84	1,897,230	4,525,617	208,289	3.41	21.7
	Sutherland 1 & 3	60-R2	*	(5)	3,146,044.45	2,069,750	1,233,597	109,504	3.48	11.3
	TOTAL ACCOUNT 316 - MISCELLANEOUS POWER PLANT EQUIPMENT				31,004,623.27	16,067,874	16,486,983	980,222	3.16	16.8
	TOTAL STEAM PRODUCTION PLANT				**1,383,888,476.07**	**726,727,259**	**888,720,223**	**51,826,619**		
	OTHER PRODUCTION PLANT									
341.00	STRUCTURES AND IMPROVEMENTS									
	Dubuque (Diesel)	50-S2	*	(3)	19,752.69	19,317	1,028	709	3.59	1.4
	Lansing (Diesel)	50-S2	*	(3)	15,025.57	15,476	0	0	-	-
	Lime Creek	50-S2	*	(3)	2,171,344.36	1,670,785	565,700	33,483	1.54	16.9
	Dubuque Unit 3 & 4	50-S2	*	(3)	4,233,766.18	4,030,802	329,977	219,991	5.20	1.5
	Burlington CT Units 1 - 4	50-S2	*	(3)	33,540.31	25,838	8,709	1,595	4.76	5.5
	Centerville CT Unit 1	50-S2	*	(3)	4,585.50	4,333	390	260	5.67	1.5
	Centerville CT Unit 2	50-S2	*	(3)	84,268.49	62,574	24,223	16,149	19.16	1.5
	Centerville CT Unit 1 & 2	50-S2	*	(3)	173,703.27	153,764	25,150	16,829	9.69	1.5
	Emery	50-S2	*	(3)	58,854,999.59	15,029,358	45,591,292	2,516,876	4.28	18.1
	Grinnell Combustion Turbine	50-S2	*	(3)	235,893.05	218,768	24,202	9,743	4.13	2.5
	Sutherland CT Units 1 - 3	50-S2	*	(3)	188,716.02	177,907	16,471	3,848	2.04	4.3
	Marshalltown Station	50-S2	*	(3)	248,927.22	256,395	0	0	-	-
	Red Cedar Cogeneration Station	50-S2	*	(3)	95,586.68	22,908	75,546	5,631	5.89	13.4
	Whispering Willow	SQUARE	*	0	58,260,314.34	5,376,192	52,884,122	2,403,824	4.13	22.0
	TOTAL ACCOUNT 341 - STRUCTURES AND IMPROVEMENTS				124,620,423.27	27,064,417	99,546,810	5,228,938	4.20	19.0
342.00	OIL SYSTEM									
	Dubuque (Diesel)	55-R2.5	*	(10)	39,471.26	39,368	4,050	2,755	6.98	1.5
	Lansing (Diesel)	55-R2.5	*	(10)	2,017.92	2,220	0	0	-	-
	Lime Creek	55-R2.5	*	(10)	767,930.50	619,818	224,906	12,979	1.69	17.3
	Burlington CT Units 1 - 4	55-R2.5	*	(10)	2,200,774.48	1,614,385	806,467	147,854	6.72	5.5
	Centerville CT Unit 1 & 2	55-R2.5	*	(10)	195,728.82	201,180	14,122	9,478	4.84	1.5
	Emery	55-R2.5	*	(10)	17,012,067.89	5,208,567	13,504,708	750,625	4.41	18.0
	Centerville (Diesel)	55-R2.5	*	(10)	9,693.03	10,126	536	365	3.77	1.5
	Grinnell Combustion Turbine	55-R2.5	*	(10)	120,807.71	117,819	15,069	6,076	5.03	2.5
	Sutherland CT Units 1 - 3	55-R2.5	*	(10)	720,968.84	369,362	423,704	94,862	13.16	4.5
	Marshalltown Station	55-R2.5	*	(10)	88,856.56	97,742	0	0	-	-
	TOTAL ACCOUNT 342 - OIL SYSTEM				21,158,317.01	8,280,587	14,993,562	1,024,994	4.84	14.6

ALLIANT ENERGY - IOWA
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2012

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
343.00	ENGINES									
	Dubuque (Diesel)	43-S2	*	(5)	191,403.75	171,856	29,118	20,362	10.64	1.4
	Lansing (Diesel)	43-S2	*	(5)	173,504.27	182,179	0	0	-	-
	Lime Creek	43-S2	*	(5)	16,081,555.24	12,539,599	4,346,034	279,335	1.74	15.6
	Dubuque Unit 3 & 4	43-S2	*	(5)	16,374,314.18	15,130,583	2,062,447	1,375,963	8.40	1.5
	Burlington CT Unit 2	43-S2	*	(5)	37,240.61	11,940	27,163	4,940	13.27	5.5
	Burlington CT Units 1 - 4	43-S2	*	(5)	395,138.13	261,719	153,176	27,966	7.08	5.5
	Centerville CT Unit 1	43-S2	*	(5)	329,019.79	280,897	64,574	43,049	13.08	1.5
	Centerville CT Unit 1 & 2	43-S2	*	(5)	938.93	753	233	155	16.51	1.5
	Emery	43-S2	*	(5)	14,717,758.00	3,400,537	12,053,109	676,622	4.60	17.8
	Centerville (Diesel)	43-S2	*	(5)	59,231.73	56,438	5,755	3,837	6.48	1.5
	Grinnell Combustion Turbine	43-S2	*	(5)	13,032.40	10,322	3,362	1,345	10.32	2.5
	Marshalltown Station	43-S2	*	(5)	727,299.51	763,664	0	0	-	-
	TOTAL ACCOUNT 343 - ENGINES				49,100,436.54	32,810,487	18,744,971	2,433,574	4.96	7.7
344.00	GENERATORS									
	Dubuque (Diesel)	50-R3	*	(15)	78,320.00	74,933	15,135	10,438	13.33	1.4
	Lansing (Diesel)	50-R3	*	(15)	28,201.22	32,431	0	0	-	-
	Lime Creek	50-R3	*	(15)	4,302,031.76	3,498,798	1,448,539	84,452	1.96	17.2
	Dubuque Unit 3 & 4	50-R3	*	(15)	4,793,253.76	5,028,842	483,400	322,368	6.73	1.5
	Burlington CT Unit 1	50-R3	*	(15)	99,021.15	100,540	13,334	2,429	2.45	5.5
	Burlington CT Unit 2	50-R3	*	(15)	257,302.60	258,513	37,385	6,818	2.65	5.5
	Burlington CT Unit 3	50-R3	*	(15)	45,557.58	46,256	6,135	1,117	2.45	5.5
	Burlington CT Unit 4	50-R3	*	(15)	10,429.16	10,589	1,405	256	2.45	5.5
	Burlington CT Units 1 - 4	50-R3	*	(15)	14,001,047.19	11,151,041	4,950,163	909,009	6.49	5.4
	Centerville CT Unit 1	50-R3	*	(15)	1,340,013.29	1,376,933	164,082	109,686	8.19	1.5
	Centerville CT Unit 2	50-R3	*	(15)	1,100,561.57	949,609	316,037	211,937	19.26	1.5
	Centerville CT Unit 1 & 2	50-R3	*	(15)	1,515,940.98	1,629,098	114,234	76,168	5.02	1.5
	Emery	50-R3	*	(15)	295,568,003.80	101,042,287	238,883,917	13,199,873	4.47	18.1
	Centerville (Diesel)	50-R3	*	(15)	410,858.18	356,841	115,646	80,120	19.50	1.4
	Grinnell Combustion Turbine	50-R3	*	(15)	4,441,563.22	4,303,617	804,181	323,971	7.29	2.5
	Sutherland CT Unit 1	50-R3	*	(15)	7,314,710.63	7,344,237	1,067,680	245,230	3.35	4.4
	Sutherland CT Unit 2	50-R3	*	(15)	7,306,758.61	7,384,107	1,018,665	234,282	3.21	4.3
	Sutherland CT Unit 3	50-R3	*	(15)	9,433,756.53	7,073,229	3,775,591	855,147	9.06	4.4
	Sutherland CT Units 1 - 3	50-R3	*	(15)	251,712.30	185,938	103,531	23,051	9.16	4.5
	Red Cedar Cogeneration Station	50-R3	*	(15)	13,881,382.41	8,183,385	7,780,205	592,858	4.27	13.1
	Whispering Willow	40-S2.5	*	(5)	319,317,180.59	46,296,191	288,986,849	13,434,989	4.21	21.5
	TOTAL ACCOUNT 344 - GENERATORS				685,517,606.53	206,327,415	550,086,114	30,724,199	4.48	17.9
345.00	ACCESSORY ELECTRIC EQUIPMENT									
	Dubuque (Diesel)	40-S1	*	0	92,036.19	89,525	2,511	1,728	1.88	1.5
	Lansing (Diesel)	40-S1	*	0	38,138.65	38,139	0	0	-	-
	Lime Creek	40-S1	*	0	1,834,547.54	1,278,390	556,158	36,676	2.00	15.2
	Dubuque Unit 3 & 4	40-S1	*	0	5,375,593.16	2,805,911	2,569,682	1,719,715	31.99	1.5
	Burlington CT Units 1 - 4	40-S1	*	0	342,337.02	271,758	70,579	13,310	3.89	5.3
	Centerville CT Unit 2	40-S1	*	0	61,022.02	35,582	25,440	16,960	27.79	1.5
	Centerville CT Unit 1 & 2	40-S1	*	0	929,463.62	607,066	322,398	215,386	23.17	1.5
	Emery	40-S1	*	0	22,505,828.15	5,523,317	16,982,511	992,573	4.41	17.1
	Centerville (Diesel)	40-S1	*	0	133,544.42	114,310	19,234	13,371	10.01	1.4
	Grinnell Combustion Turbine	40-S1	*	0	1,187,865.53	877,305	310,561	125,264	10.55	2.5
	Sutherland CT Units 1 - 3	40-S1	*	0	424,044.07	142,799	281,245	62,747	14.80	4.5
	Marshalltown Station	40-S1	*	0	107,992.16	107,992	0	0	-	-
	Whispering Willow	30-R2.5	*	0	26,566,967.74	3,234,248	23,332,720	1,162,895	4.38	20.1
	TOTAL ACCOUNT 345 - ACCESSORY ELECTRIC EQUIPMENT				59,599,380.27	15,126,342	44,473,039	4,360,625	7.32	10.2

ALLIANT ENERGY - IOWA
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2012

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT								
	Dubuque (Diesel)	40-R2 *	0	21,008.90	19,759	1,250	879	4.18	1.4
	Lime Creek	40-R2 *	0	115,730.62	43,187	72,544	4,241	3.66	17.1
	Dubuque Unit 3 & 4	40-R2 *	0	1,865,222.82	1,615,424	249,799	167,319	8.97	1.5
	Burlington CT Units 1 - 4	40-R2 *	0	26,014.64	22,619	3,396	635	2.44	5.3
	Centerville CT Unit 1 & 2	40-R2 *	0	108,176.00	98,697	9,479	6,356	5.88	1.5
	Emery	40-R2 *	0	1,192,579.09	298,133	894,446	51,647	4.33	17.3
	Centerville (Diesel)	40-R2 *	0	1,393.14	1,310	83	58	4.16	1.4
	Grinnell Combustion Turbine	40-R2 *	0	15,310.40	12,696	2,614	1,063	6.94	2.5
	Marshalltown Station	40-R2 *	0	7,782.17	7,782	0	0	-	-
	Red Cedar Cogeneration Station	40-R2 *	0	103,575.10	38,384	65,191	5,032	4.86	13.0
	Whispering Willow	40-R2 *	0	320,286.96	59,044	261,243	12,663	3.95	20.6
	TOTAL ACCOUNT 346 - MISCELLANEOUS POWER PLANT EQUIPMENT			3,777,079.84	2,217,035	1,560,045	249,893	6.62	6.2
	TOTAL OTHER PRODUCTION PLANT			**943,773,243.46**	**291,826,283**	**729,404,541**	**44,022,223**		
	DISTRIBUTION PLANT								
361.00	STRUCTURES AND IMPROVEMENTS	53-R2.5	(20)	31,546,657.02	4,796,530	33,059,458	739,208	2.34	44.7
362.00	STATION EQUIPMENT	48-R2.5	(5)	284,872,305.03	85,390,900	213,725,020	5,567,080	1.95	38.4
362.40	STATION EQUIPMENT - SYSTEM CONTROL CENTER	10-S4	0	7,936,904.60	7,866,491	70,414	23,164	0.29	3.0
364.00	POLES, TOWERS AND FIXTURES	50-R3	(60)	379,551,092.99	177,532,159	429,749,590	11,145,488	2.94	38.6
365.00	OVERHEAD CONDUCTORS AND DEVICES	55-R3	(40)	449,551,209.08	151,207,632	478,164,061	11,281,557	2.51	42.4
366.00	UNDERGROUND CONDUIT	70-R4	(25)	58,546,413.91	13,659,695	59,523,322	1,058,388	1.81	56.2
367.00	UNDERGROUND CONDUCTORS AND DEVICES	48-R3	(10)	244,524,633.97	63,216,034	205,761,063	5,421,950	2.22	37.9
368.00	LINE TRANSFORMERS	45-R3	(5)	286,814,291.05	101,809,836	199,345,170	5,725,196	2.00	34.8
369.00	SERVICES	43-R2	(50)	126,137,699.21	37,959,540	151,247,009	4,563,338	3.62	33.1
370.00	METERS	36-R1	0	86,155,080.09	6,052,207	80,102,873	3,181,653	3.69 **	25.2
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	30-R1.5	(20)	59,051,009.67	27,407,484	43,453,728	2,170,044	3.67	20.0
	TOTAL DISTRIBUTION PLANT			**2,014,687,296.62**	**676,898,508**	**1,894,201,708**	**50,877,066**		
	GENERAL PLANT								
390.00	STRUCTURES AND IMPROVEMENTS	45-R2.5	(5)	39,336,119.84	7,801,204	33,501,722	987,249	2.51	33.9
391.00	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	3,995,800.95	2,047,413	1,948,388	191,317	4.79	10.2
391.40	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS	5-SQ	0	1,628,648.97	489,210	1,139,439	467,187	28.69	2.4
392.00	TRANSPORTATION EQUIPMENT	18-L1.5	15	56,480,673.20	20,443,459	27,565,113	2,275,833	4.03	12.1
393.00	STORES EQUIPMENT	25-SQ	0	117,495.33	58,009	59,486	11,040	9.40	5.4
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	29,351,002.05	9,383,892	19,967,110	1,189,953	4.05	16.8
395.00	LABORATORY EQUIPMENT	15-SQ	0	159,113.91	57,355	101,759	69,670	43.79	1.5
396.00	POWER OPERATED EQUIPMENT	18-L2.5	10	4,571,641.04	2,075,100	2,039,377	204,759	4.48	10.0
397.00	COMMUNICATION EQUIPMENT								
	ELECTRONIC	12-SQ	0	15,032,253.61	3,307,161	11,725,093	1,684,360	11.20	7.0
	TOWER/BUILDING	25-SQ	0	8,513,237.63	60,486	8,452,752	698,954	8.21	12.1
	TOTAL ACCOUNT 397 - COMMUNICATION EQUIPMENT			23,545,491.24	3,367,647	20,177,845	2,383,314	10.12	8.5
	TOTAL GENERAL PLANT			**159,185,986.53**	**45,723,289**	**106,500,239**	**7,780,322**		
	TOTAL ELECTRIC PLANT			**4,501,535,002.68**	**1,741,175,339**	**3,618,826,711**	**154,506,230**		

ALLIANT ENERGY - IOWA
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2012

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	GAS PLANT								
	TRANSMISSION PLANT								
366.00	STRUCTURES AND IMPROVEMENTS	65-R4	(5)	319,442.02	69,223	266,191	4,909	1.54	54.2
367.00	MAINS	60-R3	(20)	41,071,858.17	17,710,096	31,576,134	733,602	1.79	43.0
369.00	MEASURING AND REGULATING STATION EQUIPMENT	35-R2.5	(5)	4,999,690.27	897,468	4,352,207	155,712	3.11	28.0
	TOTAL TRANSMISSION PLANT			**46,390,990.46**	**18,676,787**	**36,194,532**	**894,223**		
	DISTRIBUTION PLANT								
375.00	STRUCTURES AND IMPROVEMENTS	50-R1	(10)	757,821.13	199,464	634,139	15,460	2.04	41.0
376.00	MAINS	53-R1.5	(35)	167,358,948.25	67,084,970	158,849,610	3,964,237	2.37	40.1
378.00	MEASURING AND REGULATING STATION EQUIPMENT	35-L2	(10)	9,994,157.94	2,640,673	8,352,901	343,815	3.44	24.3
379.00	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	35-S0	(10)	4,301,090.97	1,157,256	3,573,944	122,514	2.85	29.2
380.00	SERVICES	41-R1.5	(70)	91,232,570.95	37,253,810	117,841,561	3,924,933	4.30	30.0
381.00	METERS	22-O1	(20)	34,960,140.56	1,007,783	40,944,386	2,626,336	7.51	15.6
382.00	METER INSTALLATIONS	41-R1.5	(70)	27,574,131.04	15,320,966	31,555,057	1,224,697	4.44	25.8
383.00	HOUSE REGULATORS	41-R3	(15)	22,134,118.57	6,412,470	19,041,766	681,409	3.08	27.9
385.00	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	32-R2	(5)	2,551,545.61	2,023,165	655,958	39,318	1.54	16.7
387.00	OTHER EQUIPMENT	25-R4	(5)	13,448.96	11,775	2,346	422	3.14	5.6
	TOTAL DISTRIBUTION PLANT			**360,877,973.98**	**133,112,332**	**381,451,668**	**12,943,141**		
	GENERAL PLANT								
390.00	STRUCTURES AND IMPROVEMENTS	42-R1.5	(10)	1,214,372.27	350,948	984,861	37,885	3.12	26.0
391.00	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	222,728.46	173,680	49,046	11,169	5.01	4.4
392.00	TRANSPORTATION EQUIPMENT	11-S3	10	3,475,805.33	2,047,055	1,081,170	224,151	6.45	4.8
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	7,357,004.70	2,670,685	4,686,320	299,178	4.07	15.7
395.00	LABORATORY EQUIPMENT	15-SQ	0	9,096.61	7,227	1,870	748	8.22	2.5
396.00	POWER OPERATED EQUIPMENT	19-S1.5	10	1,676,692.16	672,421	836,602	104,947	6.26	8.0
397.00	COMMUNICATION EQUIPMENT	12-SQ	0	714,290.02	621,477	92,813	20,166	2.82	4.6
	TOTAL GENERAL PLANT			**14,669,989.55**	**6,543,493**	**7,732,684**	**698,244**		
	TOTAL GAS PLANT			**421,938,953.99**	**158,332,612**	**425,378,884**	**14,535,608**		
	STEAM UTILITY PLANT								
	PRODUCTION PLANT								
312.00	STRUCTURES AND IMPROVEMENTS	100-S2.5 *	(10)	1,078,106.35	603,472	582,445	46,652	4.33	12.5
313.00	BOILER PLANT AND PUMPING EQUIPMENT	80-S2.5 *	(15)	18,533,179.68	13,194,911	8,118,246	650,287	3.51	12.5
314.00	MISCELLANEOUS STATION EQUIPMENT - PRODUCTION	65-R3 *	0	3,804,415.17	2,084,758	1,719,657	139,246	3.66	12.3
315.00	MISCELLANEOUS STATION EQUIPMENT - OTHER	55-R3 *	0	53,159.02	27,712	25,447	2,097	3.94	12.1
	TOTAL PRODUCTION PLANT			**23,468,860.22**	**15,910,853**	**10,445,795**	**838,282**		

ALLIANT ENERGY - IOWA
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2012

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	DISTRIBUTION PLANT								
358.00	STRUCTURES AND IMPROVEMENTS	50-R3 *	(5)	12,964.43	3,165	10,448	841	6.49	12.4
359.00	MAINS AND SERVICES	65-R3 *	(50)	11,333,542.19	5,872,960	11,127,353	899,123	7.93	12.4
360.00	METERS	35-S2 *	(5)	106,024.40	17,457	93,869	8,067	7.61	11.6
	TOTAL DISTRIBUTION PLANT			**11,452,531.02**	**5,893,582**	**11,231,670**	**908,031**		
	GENERAL PLANT								
373.00	TRANSPORTATION EQUIPMENT	12-R4	10	27,772.88	21,311	3,685	0	-	-
	TOTAL GENERAL PLANT			**27,772.88**	**21,311**	**3,685**	**0**		
	TOTAL STEAM UTILITY PLANT			**34,949,164.12**	**21,825,746**	**21,681,150**	**1,746,313**		
	COMMON PLANT								
390.00	STRUCTURES AND IMPROVEMENTS	50-R3	(5)	94,523,520.39	24,283,472	74,966,224	1,737,755	1.84	43.1
391.00	OFFICE FURNITURE AND EQUIPMENT	20-SQ	0	15,537,213.32	9,560,231	5,976,982	394,367	2.54	15.2
391.40	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS	5-SQ	0	9,629,871.46	4,986,343	4,643,528	2,112,411	21.94	2.2
392.00	TRANSPORTATION EQUIPMENT	12-L3	20	24,881,460.97	10,056,591	9,848,578	1,493,155	6.00	6.6
393.00	STORES EQUIPMENT	25-SQ	0	71,695.56	66,994	4,702	1,041	1.45	4.5
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	5,070,905.16	2,409,691	2,661,214	164,145	3.24	16.2
396.00	POWER OPERATED EQUIPMENT	18-L3	20	5,854,042.61	2,404,580	2,278,654	195,519	3.34	11.7
397.00	COMMUNICATION EQUIPMENT								
	ELECTRONIC	12-SQ	0	25,644,189.64	8,697,029	16,947,161	2,340,809	9.13	7.2
	TOWER/BUILDING	25-SQ	0	6,249,503.96	1,058,728	5,190,776	261,849	4.19	19.8
	TOTAL ACCOUNT 397 - COMMUNICATION EQUIPMENT			31,893,693.60	9,755,757	22,137,937	2,602,658	8.16	8.5
397.40	COMMUNICATION EQUIPMENT - IDEN								
	ELECTRONIC	10-SQ	0	9,760,056.70	7,186,128	2,573,929	1,556,124	15.94	1.7
	TOWER/BUILDING	25-SQ	0	1,312,295.15	499,918	812,377	48,698	3.71	16.7
	TOTAL ACCOUNT 397.4 - COMMUNICATION EQUIPMENT - IDEN			11,072,351.85	7,686,046	3,386,306	1,604,822	14.49	2.1
398.00	MISCELLANEOUS EQUIPMENT	10-SQ	0	96,870.33	83,522	13,348	5,339	5.51	2.5
	TOTAL COMMON PLANT			**198,631,625.25**	**71,293,227**	**125,917,473**	**10,311,212**		
	NONDEPRECIABLE PLANT								
	ELECTRIC PLANT								
302.00	FRANCHISES AND CONSENTS			295,044.74					
303.00	MISCELLANEOUS INTANGIBLE PLANT			35,425,105.77					
310.00	LAND			1,813,485.06					
340.00	LAND			15,205,575.63					
360.00	LAND			13,100,004.42					
389.00	LAND			2,552,051.77					
	TOTAL ELECTRIC PLANT			**68,391,267.39**					

ALLIANT ENERGY - IOWA
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2012

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	GAS PLANT								
302.00	FRANCHISES AND CONSENTS			150,730.72					
303.00	MISCELLANEOUS INTANGIBLE PLANT			328,971.34					
365.00	LAND			689,684.66					
374.00	LAND			584,493.26					
389.00	LAND			146,269.95					
	TOTAL GAS PLANT			**1,900,149.93**					
	COMMON PLANT								
303.00	LAND			38,319,380.02					
389.00	LAND			3,157,347.76					
	TOTAL COMMON PLANT			**41,476,727.78**					
	TOTAL NONDEPRECIABLE PLANT			**111,768,145.10**					
	TOTAL ELECTRIC, GAS, STEAM UTILITY & COMMON PLANT			**5,268,822,891.14**	**1,992,626,924**	**4,191,804,218**	**181,099,363**		

* LIFE SPAN PROCEDURE IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE
** ACCRUAL RATE FOR ACCOUNT 370.10, METERS - AMI, WILL BE 7.00% WHICH IS BASED ON A 15-YEAR AVERAGE SERVICE LIFE AND NEGATIVE 5% NET SALVAGE

ALLIANT ENERGY - MINNESOTA
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2012

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	ELECTRIC PLANT									
	STEAM PRODUCTION PLANT									
311.00	STRUCTURES AND IMPROVEMENTS									
	Fox Lake Unit 1	100-S2	*	(20)	530,218.05	638,736	(2,474)	0	-	-
	Fox Lake Unit 3	100-S2	*	(20)	2,866,334.03	3,373,553	66,048	14,678	0.51	4.5
	Fox Lake Units 1 & 3	100-S2	*	(20)	67,758.73	38,450	42,860	9,525	14.06	4.5
	TOTAL ACCOUNT 311 - STRUCTURES AND IMPROVEMENTS				3,464,310.81	4,050,739	106,434	24,203	0.70	4.4
312.00	BOILER PLANT EQUIPMENT									
	Fox Lake Unit 1	75-S2	*	(20)	973,684.20	1,168,421	0	0	-	-
	Fox Lake Unit 3	75-S2	*	(20)	12,925,615.40	14,411,108	1,099,630	245,546	1.90	4.5
	Fox Lake Units 1 & 3	75-S2	*	(20)	101,582.82	67,161	54,738	12,164	11.97	4.5
	TOTAL ACCOUNT 312 - BOILER PLANT EQUIPMENT				14,000,882.42	15,646,690	1,154,368	257,710	1.84	4.5
314.00	TURBOGENERATOR UNITS									
	Fox Lake Unit 1	75-S3	*	(10)	760,756.92	836,833	0	0	-	-
	Fox Lake Unit 3	75-S3	*	(10)	4,012,870.09	4,252,569	161,588	36,242	0.90	4.5
	Fox Lake Units 1 & 3	75-S3	*	(10)	10,422.84	8,568	2,897	644	6.18	4.5
	TOTAL ACCOUNT 314 - TURBOGENERATOR UNITS				4,784,049.85	5,097,970	164,485	36,886	0.77	4.5
315.00	ACCESSORY ELECTRIC EQUIPMENT									
	Fox Lake Unit 1	65-R4	*	(5)	238,294.84	250,210	0	0	-	-
	Fox Lake Unit 3	65-R4	*	(5)	1,689,253.47	1,695,139	78,577	17,462	1.03	4.5
	Fox Lake Units 1 & 3	65-R4	*	(5)	696,394.52	644,075	87,139	19,364	2.78	4.5
	TOTAL ACCOUNT 315 - ACCESSORY ELECTRIC EQUIPMENT				2,623,942.83	2,589,424	165,716	36,826	1.40	4.5
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	Fox Lake Unit 1	60-S1.5	*	(5)	29,649.78	31,132	0	0	-	-
	Fox Lake Unit 3	60-S1.5	*	(5)	545,896.32	469,013	104,178	23,300	4.27	4.5
	Fox Lake Units 1 & 3	60-S1.5	*	(5)	451,226.24	312,093	161,695	35,987	7.98	4.5
	TOTAL ACCOUNT 316 - MISCELLANEOUS POWER PLANT EQUIPMENT				1,026,772.34	812,238	265,873	59,287	5.77	4.5
	TOTAL STEAM PRODUCTION PLANT				**25,899,958.25**	**28,197,061**	**1,856,876**	**414,912**		

ALLIANT ENERGY - MINNESOTA
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2012

	ACCOUNT (1)	SURVIVOR CURVE (2)		NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	OTHER PRODUCTION PLANT									
342.00	OIL SYSTEM									
	Hills	50-S0.5	*	(5)	97,782.11	102,671	0	0	-	-
	TOTAL ACCOUNT 342 - OIL SYSTEM				97,782.11	102,671	0	0	-	-
343.00	ENGINES									
	Hills	40-L4	*	(5)	230,720.54	231,319	10,938	3,134	1.36	3.5
	TOTAL ACCOUNT 343 - ENGINES				230,720.54	231,319	10,938	3,134	1.36	3.5
344.00	GENERATORS									
	Hills	60-S2.5	*	0	207,873.71	204,387	3,487	996	0.48	3.5
	TOTAL ACCOUNT 344 - GENERATORS				207,873.71	204,387	3,487	996	0.48	3.5
345.00	ACCESSORY ELECTRIC EQUIPMENT									
	Hills	30-R1.5	*	(5)	324,856.45	325,715	15,384	4,536	1.40	3.4
	TOTAL ACCOUNT 345 - ACCESSORY ELECTRIC EQUIPMENT				324,856.45	325,715	15,384	4,536	1.40	3.4
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT									
	Hills	30-R4	*	0	15,085.26	15,085	0	0	-	-
	TOTAL ACCOUNT 346 - MISCELLANEOUS POWER PLANT EQUIPMENT				15,085.26	15,085	0	0	-	-
	TOTAL OTHER PRODUCTION PLANT				**876,318.07**	**879,177**	**29,809**	**8,666**		
	DISTRIBUTION PLANT									
361.00	STRUCTURES AND IMPROVEMENTS	50-R2.5		(5)	651,703.89	208,870	475,419	11,754	1.80	40.4
362.00	STATION EQUIPMENT	25-O1		(10)	23,655,287.07	9,815,557	16,205,259	773,865	3.27	20.9
364.00	POLES, TOWERS AND FIXTURES	47-R1		(50)	36,174,282.58	21,950,463	32,310,961	845,571	2.34	38.2
365.00	OVERHEAD CONDUCTORS AND DEVICES	42-R1		(40)	38,075,041.70	14,861,619	38,443,439	1,183,562	3.11	32.5
366.00	UNDERGROUND CONDUIT	40-R3		(5)	956,605.70	286,423	718,013	25,415	2.66	28.3
367.00	UNDERGROUND CONDUCTORS AND DEVICES	42-R2		(25)	16,450,763.98	4,580,539	15,982,916	495,439	3.01	32.3
368.00	LINE TRANSFORMERS	39-R1		(5)	16,078,598.95	6,496,671	10,385,858	333,651	2.08	31.1
369.00	SERVICES	40-O1		(50)	9,624,775.46	2,071,725	12,365,438	355,067	3.69	34.8
370.00	METERS	43-R1.5		(5)	2,966,769.05	(996,797)	4,111,905	222,854	7.51 **	18.5
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	23-L1		(20)	4,346,965.75	1,631,564	3,584,795	222,506	5.12	16.1
	TOTAL DISTRIBUTION PLANT				**148,980,794.13**	**60,906,634**	**134,584,003**	**4,469,684**		

ALLIANT ENERGY - MINNESOTA
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2012

	ACCOUNT	SURVIVOR CURVE	NET SALVAGE PERCENT	ORIGINAL COST	BOOK DEPRECIATION RESERVE	FUTURE ACCRUALS	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	COMPOSITE REMAINING LIFE
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)=(7)/(4)	(9)=(6)/(7)
	GENERAL PLANT								
390.00	STRUCTURES AND IMPROVEMENTS	50-S3	(5)	4,007,634.08	826,626	3,381,390	83,133	2.07	40.7
391.10	OFFICE FURNITURE AND EQUIPMENT - EXCEPT COMPUTERS	20-SQ	0	181,075.65	63,196	117,880	8,606	4.75	13.7
391.40	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS	5-SQ	0	36,578.33	28,115	8,463	4,718	12.90	1.8
392.00	TRANSPORTATION EQUIPMENT - TRUCKS, TRAILERS AND VANS	13-L3	10	8,035,158.09	3,623,385	3,608,257	569,462	7.09	6.3
393.00	STORES EQUIPMENT	25-SQ	0	16,419.74	12,117	4,303	615	3.75	7.0
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	972,127.90	364,947	607,181	37,317	3.84	16.3
395.00	LABORATORY EQUIPMENT	15-SQ	0	35,684.18	31,827	3,857	2,571	7.20	1.5
396.00	POWER OPERATED EQUIPMENT	13-L3	10	1,410,598.37	940,633	328,906	77,058	5.46	4.3
397.00	COMMUNICATION EQUIPMENT								
	ELECTRONIC	12-SQ	0	1,107,115.15	753,701	353,414	59,758	5.40	5.9
	TOWER/BUILDING	25-SQ	0	2,796,927.06	1,330,661	1,466,266	102,598	3.67	14.3
	TOTAL ACCOUNT 397 - COMMUNICATION EQUIPMENT			3,904,042.21	2,084,362	1,819,680	162,356	4.16	11.2
	TOTAL GENERAL PLANT			**18,599,318.55**	**7,975,208**	**9,879,917**	**945,836**		
	TOTAL ELECTRIC PLANT			**194,356,389.00**	**97,958,080**	**146,350,605**	**5,839,098**		
	GAS PLANT								
	DISTRIBUTION PLANT								
375.00	STRUCTURES AND IMPROVEMENTS	40-S1	0	3,469.96	1,067	2,403	64	1.84	37.5
376.00	MAINS	56-S2	(30)	8,062,945.25	3,698,717	6,783,112	169,602	2.10	40.0
378.00	MEASURING AND REGULATING EQUIPMENT - GENERAL	32-S1.5	(10)	128,113.04	22,061	118,863	6,220	4.86	19.1
379.00	MEASURING AND REGULATING EQUIPMENT - CITY GATE	16-S2.5	(10)	442,847.59	212,138	274,994	24,239	5.47	11.3
380.10	SERVICES	38-R4	(80)	4,346,548.73	2,338,557	5,485,231	254,188	5.85	21.6
381.00	METERS	28-R2	(50)	2,036,989.62	628,638	2,426,846	137,952	6.77	17.6
382.00	METER INSTALLATIONS	38-R4	(80)	1,618,276.73	875,026	2,037,872	85,886	5.31	23.7
383.00	HOUSE REGULATORS	32-L3	(15)	413,729.06	96,581	379,207	27,310	6.60	13.9
385.00	INDUSTRIAL MEASURING AND REGULATING STATION EQUIPMENT	15-S0.5	0	38,782.48	37,384	1,398	304	0.78	4.6
	TOTAL DISTRIBUTION PLANT			**17,091,702.46**	**7,910,169**	**17,509,926**	**705,765**		
	GENERAL PLANT								
390.00	STRUCTURES AND IMPROVEMENTS	30-S3	0	259,524.05	103,483	156,041	9,361	3.61	16.7
392.20	TRANSPORTATION EQUIPMENT - TRUCKS	11-L4	5	23,837.99	12,246	10,400	2,670	11.20	3.9
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	122,322.78	61,574	60,749	6,779	5.54	9.0
395.00	LABORATORY EQUIPMENT	15-SQ	0	4,910.58	2,707	2,204	882	17.96	2.5
	TOTAL GENERAL PLANT			**410,595.40**	**180,010**	**229,394**	**19,692**		
	TOTAL GAS PLANT			**17,502,297.86**	**8,090,179**	**17,739,320**	**725,457**		

ALLIANT ENERGY - MINNESOTA
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2012

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	COMMON PLANT								
390.00	STRUCTURES AND IMPROVEMENTS	50-R3	(5)	271,932.72	34,551	250,978	5,797	2.13	43.3
391.00	OFFICE FURNITURE AND EQUIPMENT								
	EXCEPT COMPUTERS	20-SQ	0	41,676.35	23,037	18,639	2,029	4.87	9.2
	COMPUTERS	5-SQ	0	3,714.27	1,354	2,360	944	25.42	2.5
392.00	TRANSPORTATION EQUIPMENT								
	TRUCKS, TRAILERS AND VANS	12-S3	20	3,267,870.28	1,425,177	1,189,119	216,703	6.63	5.5
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	0	81,329.43	25,129	56,200	3,073	3.78	18.3
396.00	POWER OPERATED EQUIPMENT	12-L2.5	10	595,372.38	329,654	206,181	38,577	6.48	5.3
397.00	COMMUNICATION EQUIPMENT								
	ELECTRONIC	12-SQ	0	909,777.99	410,108	499,670	83,551	9.18	6.0
	TOWER/BUILDING	25-SQ	0	246,071.23	118,953	127,118	6,625	2.69	19.2
	TOTAL ACCOUNT 397 - COMMUNICATION EQUIPMENT			1,155,849.22	529,061	626,788	90,176	7.80	7.0
397.40	COMMUNICATION EQUIPMENT - IDEN								
	ELECTRONIC	10-SQ	0	6,104,539.23	4,813,661	1,290,878	778,535	12.75	1.7
	TOWER/BUILDING	25-SQ	0	1,491,163.66	533,690	957,474	55,007	3.69	17.4
	TOTAL ACCOUNT 397.4 - COMMUNICATION EQUIPMENT - IDEN			7,595,702.89	5,347,351	2,248,352	833,542	10.97	2.7
	TOTAL COMMON PLANT			**13,013,447.54**	**7,715,314**	**4,598,617**	**1,190,841**		
	NONDEPRECIABLE PLANT								
	ELECTRIC PLANT								
302.00	FRANCHISES AND CONSENTS			3,905.29					
303.00	MISCELLANEOUS PLANT			36,151.30					
310.10	LAND			26,781.89					
310.20	LAND RIGHTS			2,883.60					
340.10	LAND			15,597.05					
340.20	LAND RIGHTS			5.30					
360.00	LAND			200,298.43					
389.10	LAND			230,209.25					
389.20	LAND RIGHTS			452.75					
	TOTAL ELECTRIC PLANT			**516,284.86**					

ALLIANT ENERGY - MINNESOTA
SUMMARY OF ESTIMATED SURVIVOR CURVES, NET SALVAGE, ORIGINAL COST, BOOK DEPRECIATION RESERVE AND
CALCULATED ANNUAL DEPRECIATION RATES AS OF DECEMBER 31, 2012

	ACCOUNT (1)	SURVIVOR CURVE (2)	NET SALVAGE PERCENT (3)	ORIGINAL COST (4)	BOOK DEPRECIATION RESERVE (5)	FUTURE ACCRUALS (6)	CALCULATED ANNUAL ACCRUAL AMOUNT (7)	CALCULATED ANNUAL ACCRUAL RATE (8)=(7)/(4)	COMPOSITE REMAINING LIFE (9)=(6)/(7)
	GAS PLANT								
374.00	LAND			4,194.36					
389.10	LAND			86,508.01					
	TOTAL GAS PLANT			**90,702.37**					
	COMMON PLANT								
303.00	MISCELLANEOUS PLANT			2,326.45					
389.10	LAND			43,323.56					
	TOTAL COMMON PLANT			**45,650.01**					
	TOTAL NONDEPRECIABLE PLANT			**652,637.24**					
	TOTAL ELECTRIC, GAS & COMMON PLANT			**225,524,771.64**	**113,763,573**	**168,688,542**	**7,755,396**		

* LIFE SPAN PROCEDURE IS USED. CURVE SHOWN IS INTERIM SURVIVOR CURVE
** ACCRUAL RATE FOR ACCOUNT 370.10, METERS - AMI, WILL BE 7.00% WHICH IS BASED ON A 15-YEAR AVERAGE SERVICE LIFE AND NEGATIVE 5% NET SALVAGE

Part 3: Plant in service for the State of Minnesota, electric, gas and common for 2012

INTERSTATE POWER AND LIGHT COMPANY
ELECTRIC UTILITY PLANT IN SERVICE - MINNESOTA

Account	1/1/2012 Beginning_Balance	Additions	Retirements	Transfers	Adjustments	12/31/2012 Ending_Balance
302 - Franchises and consents	3,905.29	-	-	-	-	3,905.29
303 - Misc intangible plant	36,151.30	-	-	-	-	36,151.30
Intangible Plant Electric	40,056.59	-	-	-	-	40,056.59
310 - Land and land rights	29,665.49	-	-	-	-	29,665.49
311 - Structures and Improvements	3,467,298.22	(2,987.41)	-	-	-	3,464,310.81
312 - Boiler plant equipment	13,984,282.10	25,219.55	(8,620.43)	-	-	14,000,881.22
312.1 - Boiler plant equipment - unit train	-	-	-	-	-	-
312.5 - Boiler plant equipment (combustion initiative)	-	-	-	-	-	-
314 - Turbogenerator units	4,784,049.85	-	-	-	-	4,784,049.85
315 - Accessory electric equipment	2,618,362.03	9,669.29	(4,088.50)	-	-	2,623,942.82
316 - Misc power plant equipment	1,026,772.37	-	-	-	-	1,026,772.37
316.8 - Misc power plant equip (combustion initiative)	-	-	-	-	-	-
Fossil Generation Plant	25,910,430.06	31,901.43	(12,708.93)	-	-	25,929,622.56
340 - Land and land rights	15,602.35	-	-	-	-	15,602.35
341 - Structures and improvements	146,913.97	-	(146,913.97)	-	-	-
342 - Fuel holders,producrs,accessr	254,949.36	-	(157,167.25)	-	-	97,782.11
343 - Prime movers	1,354,253.57	-	(1,123,533.03)	-	-	230,720.54
344 - Generators	861,102.50	-	(653,228.79)	-	-	207,873.71
345 - Accessory electric equipment	432,373.85	-	(107,517.40)	-	-	324,856.45
346 - Misc power plant equipment	25,125.44	-	(10,040.18)	-	-	15,085.26
Other Generation Plant	3,090,321.04	-	(2,198,400.62)	-	-	891,920.42
360 - Land and land rights	200,846.46	(548.03)	-	-	-	200,298.43
361 - Structures and improvements	614,655.32	37,048.57	-	-	-	651,703.89
362 - Station equipment	20,059,932.60	3,773,836.83	(24,286.28)	(154,196.07)	-	23,655,287.08
362.4 - Station equipment - System Control Center	-	-	-	-	-	-
364 - Poles, towers and fixtures	33,932,637.51	2,674,908.47	(433,263.38)	-	-	36,174,282.60
365 - Overhead conductors, devices	36,576,271.61	1,582,067.57	(164,119.29)	80,821.71	-	38,075,041.60
366 - Underground conduit	932,283.95	24,321.75	-	-	-	956,605.70
367 - Undergrnd conductors, devices	15,757,844.73	784,326.45	(91,407.20)	-	-	16,450,763.98
368 - Line transformers	14,786,523.12	-	(135,124.49)	1,427,200.32	-	16,078,598.95
369 - Services	8,947,006.94	777,102.03	(99,333.51)	-	-	9,624,775.46
370 - Meters	2,769,401.08	-	(101,476.89)	298,844.86	-	2,966,769.05
373 - Street lighting,signal system	4,210,978.85	380,838.50	(244,851.60)	-	-	4,346,965.75
Distribution Plant - Electric	138,788,382.17	10,033,902.14	(1,293,862.64)	1,652,670.82	-	149,181,092.49
389 - Land and land rights	230,662.00	-	-	-	-	230,662.00
390 - Structures and improvements	3,544,480.98	484,850.14	(32,679.57)	10,982.53	-	4,007,634.08
390.1 - Leasehold improvements	10,982.53	-	-	(10,982.53)	-	-
391 - Office furniture, equipment	91,322.34	102,138.19	(12,384.88)	-	-	181,075.65
391.4 - Computer equipment	36,578.33	-	-	-	-	36,578.33
392 - Transportation equipment	8,144,972.76	-	(89,166.15)	(20,648.52)	-	8,035,158.09
393 - Stores equipment	16,419.74	-	-	-	-	16,419.74
394 - Tools, shop, garage equipment	949,585.62	25,785.20	(3,242.92)	-	-	972,127.90
395 - Laboratory equipment	35,684.18	-	-	-	-	35,684.18
396 - Power operated equipment	1,410,598.37	-	-	-	-	1,410,598.37
397.0 - Communication equipment - Electronic	1,109,544.96	(2,429.81)	-	-	-	1,107,115.15
397.1 - Communication equipment - Structures	2,796,927.06	-	-	-	-	2,796,927.06
398 - Miscellaneous equipment	-	-	-	-	-	-
General Plant - Electric	18,377,758.87	610,343.72	(137,473.52)	(20,648.52)	-	18,829,980.55
Total Minnesota Electric UPIS	186,206,948.73	10,676,147.29	(3,642,445.71)	1,632,022.30	-	194,872,672.61

INTERSTATE POWER AND LIGHT COMPANY
GAS UTILITY PLANT - MINNESOTA

Account	1/1/2012 Beginning_Balance	Additions	Retirements	Transfers	12/31/2012 Ending_Balance
302 - Franchises and consents		-	-	-	-
303 - Misc intangible plant		-	-	-	-
Intangible Plant Gas	-	-	-	-	-
304 - Gas Land and land rights	-	-	-	-	-
305 - Gas Structures + Improvements	-	-	-	-	-
311 - Liquified petroleum gas equip	-	-	-	-	-
319 - Gas mixing equipment	-	-	-	-	-
320 - Other equipment	-	-	-	-	-
Manufactured Gas Production Plant	-	-	-	-	-
365 - Land and land rights	-	-	-	-	-
366 - Structures and improvements	-	-	-	-	-
367 - Mains	-	-	-	-	-
369 - Measure/reg station equip	-	-	-	-	-
Transmission Plant - Gas	-	-	-	-	-
374 - Land and land rights	4,194.36	-	-	-	4,194.36
375 - Structures and Improvements	2,750.89	719.07	-	-	3,469.96
376 - Mains	7,831,090.75	221,632.58	(14,681.97)	24,903.89	8,062,945.25
378 - Meas. and reg. stat. eq.-Gen	130,276.03	1,437.78	(3,600.77)	-	128,113.04
379 - Meas. and reg. stat. eq.-City	429,147.42	35,233.33	(21,533.16)	-	442,847.59
380 - Services	5,790,477.84	268,828.01	(69,576.50)	(1,643,180.62)	4,346,548.73
381 - Meters	1,687,689.09	-	(8,701.54)	358,002.07	2,036,989.62
382 - Meter installations	-	-	-	1,618,276.73	1,618,276.73
383 - House regulators	410,416.91	-	(6,237.49)	9,549.64	413,729.06
385 - Ind. measuring and regulating	38,782.48	-	-	-	38,782.48
387 - Other equipment	-	-	-	-	-
Distribution Plant - Gas	16,324,825.77	527,850.77	(124,331.43)	367,551.71	17,095,896.82
389 - Land and land rights	86,508.01	-	-	-	86,508.01
390 - Structures and improvements	259,524.05	-	-	-	259,524.05
391 - Office furniture and equip	-	-	-	-	-
391.4 - Computer equipment	-	-	-	-	-
392 - Transportation equipment	23,837.99	-	-	-	23,837.99
394 - Tools, shop and garage equip	125,083.10	1,494.11	(4,254.43)	-	122,322.78
395 - Laboratory equipment	4,910.58	-	-	-	4,910.58
396 - Power operated equipment	-	-	-	-	-
397 - Communication equipment	-	-	-	-	-
398 - Miscellaneous equipment	-	-	-	-	-
General Plant - Gas	499,863.73	1,494.11	(4,254.43)	-	497,103.41
Total Minnesota Gas UPIS	16,824,689.50	529,344.88	(128,585.86)	367,551.71	17,593,000.23

INTERSTATE POWER AND LIGHT COMPANY
COMMON UTILITY PLANT - MINNESOTA

Account	1/1/2012 Beginning_Balance	Additions	Retirements	Transfers	12/31/2012 Ending_Balance
303 - Misc intangible plant	2,326.45	-	-	-	2,326.45
389 - Land and land rights	43,323.56	-	-	-	43,323.56
390 - Structures and improvements	271,932.72	-	-	-	271,932.72
390.1 - Leasehold improvements	-	-	-	-	-
391 - Office furniture, equipment	41,676.35	-	-	-	41,676.35
391.4 - Computer equipment	3,714.27	-	-	-	3,714.27
392 - Transportation equipment	2,933,368.75	334,501.53	-	-	3,267,870.28
393 - Stores equipment	-	-	-	-	-
394 - Tools, shop, garage equipment	81,329.43	-	-	-	81,329.43
395 - Laboratory equipment	-	-	-	-	-
396 - Power operated equipment	573,571.48	21,800.90	-	-	595,372.38
397.0 - Communication Equipment - Electronics	853,995.35	55,782.64	-	-	909,777.99
397.1 - Communication Equipment - Structures	241,715.22	4,356.01	-	-	246,071.23
397.4 - Communication equipment - IDEN Electronics	6,104,539.23	-	-	-	6,104,539.23
397.5 - Communication equipment - IDEN Structures	1,491,163.66	-	-	-	1,491,163.66
398 - Miscellaneous equipment	-	-	-	-	-
Total Minnesota Common UPIS	12,642,656.47	416,441.08	-	-	13,059,097.55

Part 4: Accumulated Reserve for Depreciation for the State of Minnesota electric, gas and common for 2012

INTERSTATE POWER AND LIGHT COMPANY
ACCUMULATED DEPRECIATION
ELECTRIC UTILITY - MINNESOTA

ACCOUNT MAJ	MIN	BEGINNING BALANCE 12/31/2011	Depreciation Expense	Retirements	Salvage	Removal Cost	Other	ENDING BALANCE 12/31/2012
311	00	4,028,162	23,389	-	-	-	(814)	4,050,737
312	00	15,682,448	51,799	(8,620)	-	(372)	(78,564)	15,646,690
312	50	-						-
314	00	5,067,800	32,805	-	-	-	(2,635)	5,097,970
315	00	2,571,527	23,206	(4,089)	-	(1,144)	(77)	2,589,424
316	00	756,568	58,368	-	-	-	(2,697)	812,239
316	80	-						-
		28,106,505	189,566	(12,709)	-	(1,516)	(84,787)	28,197,059
341	00	146,914	-	(146,914)	-	-	-	-
342	00	267,697	-	(157,167)	-	-	(7,858)	102,671
343	00	1,355,076	1,708	(1,123,533)	-	-	(1,932)	231,319
344	00	841,398	6,483	(653,229)	-	-	9,735	204,387
345	00	432,470	707	(107,517)	-	-	55	325,715
346	00	25,125	-	(10,040)	-	-	-	15,085
		3,068,680	8,898	(2,198,401)	-	-	-	879,177
361	00	197,397	11,473	-	-	-	-	208,870
362	00	9,305,307	668,059	(24,286)	-	(39,335)	(94,188)	9,815,557
362	10	-						-
364	00	21,896,115	816,242	(433,263)	1,337	(329,969)	-	21,950,463
365	00	14,104,941	1,168,638	(164,119)	8,827	(257,988)	1,321	14,861,619
366	00	261,167	25,256	-	-	-	-	286,423
367	00	4,228,593	479,295	(91,407)	22	(35,963)	-	4,580,539
368	00	6,215,063	361,796	(135,124)	40,735	(69,679)	83,880	6,496,671
369	00	1,956,060	330,905	(99,334)	793	(116,699)	-	2,071,725
370	00	(678,829)	224,897	(101,477)	-	(447,330)	5,942	(996,797)
373	00	1,682,559	213,789	(244,852)	1	(19,933)	-	1,631,564
		59,168,373	4,300,350	(1,293,863)	51,716	(1,316,896)	(3,045)	60,906,634
390	00	796,932	77,527	(32,680)	-	(17,724)	2,571	826,626
390	10	2,603			-		(2,603)	-
391	00	69,167	6,439	(12,385)	-	(26)	-	63,196
391	40	22,147	5,967	-	-	-	-	28,115
392	00	3,105,450	618,078	(89,166)	-	-	(10,977)	3,623,385
393	00	11,502	615	-	-	-	-	12,117
394	00	322,150	38,232	(3,243)	7,832	-	(24)	364,947
395	00	29,554	2,273	-	-	-	-	31,827
396	00	860,210	80,423	-	-	-	-	940,633
397	00	682,754	70,946	-	-	-	-	753,701
397	10	1,226,161	104,500	-	-	-	-	1,330,661
398	00	0	-	-	-	-	-	0
		7,128,632	1,005,000	(137,474)	7,832	(17,750)	(11,033)	7,975,207
		97,472,189	5,503,814	(3,642,446)	59,548	(1,336,163)	(98,865)	97,958,077

INTERSTATE POWER AND LIGHT COMPANY
ACCUMULATED DEPRECIATION
GAS UTILITY - MINNESOTA

ACCOUNT MAJ	MIN	BEGINNING BALANCE 12/31/2011	Depreciation Expense	Retirements	Salvage	Removal Costs	Other	ENDING BALANCE 12/31/2012
305	00	-	-	-	-	-	-	-
311	00	-	-	-	-	-	-	-
319	00	-	-	-	-	-	-	-
320	00	-	-	-	-	-	-	-
		-	-	-	-	-	-	-
366	00	-	-	-	-	-	-	-
367	00	-	-	-	-	-	-	-
369	00	-	-	-	-	-	-	-
		-	-	-	-	-	-	-
375	00	883	184	-	-	-	-	1,067
376	00	3,551,436	163,244	(14,682)	-	(7,933)	6,652	3,698,717
378	00	21,022	5,396	(3,601)	-	(756)		22,061
379	00	221,678	22,152	(21,533)	-	(10,159)		212,138
380	00	3,009,086	310,641	(69,577)	(220)	(38,002)	(873,371)	2,338,557
381	00	521,435	128,286	(8,702)	-	-	(12,381)	628,638
382	00	-	7,680	-	-	-	867,346	875,026
383	00	75,459	27,244	(6,237)	463	(460)	113	96,581
385	00	37,195	189	-	-	-	-	37,384
387	00	-	-	-	-	-	-	-
		7,438,194	665,016	(124,331)	243	(57,311)	(11,641)	7,910,169
390	00	94,101	9,382	-	-			103,483
391	00	-	-	-	-			-
391	40	-	-	-	-			-
392	00	10,359	1,887	-	-			12,246
394	00	55,109	10,719	(4,254)	-			61,574
395	00	2,589	118	-	-			2,707
396	00	-	-	-	-			-
397	00	-	-	-	-			-
398	00	-	-	-	-			-
		162,159	22,106	(4,254)	-	-	-	180,010
		7,600,353	687,121	(128,586)	243	(57,311)	(11,641)	8,090,179

INTERSTATE POWER AND LIGHT COMPANY
ACCUMULATED DEPRECIATION
COMMON UTILITY - MINNESOTA

ACCOUNT MAJ	MIN	BEGINNING BALANCE 12/31/2011	Depreciation Expense	Retirements	Salvage	Removal Costs	Other	ENDING BALANCE 12/31/2012
390	00	28,750	5,801	-	-	-	-	34,551
391	00	21,006	2,031	-	-	-		23,037
391	40	2,523	(1,169)	-	-	-		1,354
392	00	1,211,559	213,618	-	-	-		1,425,177
393	00	-	-	-	-	-		-
394	00	22,056	3,073	-	-	-		25,129
395	00	-	-	-	-	-		-
396	00	290,793	38,861	-	-	-		329,654
397	00	349,173	40,514	-	-	-	20,420	410,108
397	10	136,736	2,636	-	-	-	(20,420)	118,953
397	40	3,908,792	793,409	-	-	-	111,460	4,813,661
397	50	598,812	46,338	-	-	-	(111,460)	533,690
398	00	-	-	-	-	-		-
		6,570,200	1,145,113	-	-	-	-	7,715,312

Part 5: Major changes to property in 2012 and future major additions or retirements in 2013

INTERSTATE POWER AND LIGHT COMPANY
Major Changes to Property, Plant and Equipment in 2012

During the fourth quarter of 2012, the Montgomery CT was retired and Dubuque Units 3 & 4 were transferred from Steam Production accounts to Other Production accounts.

INTERSTATE POWER AND LIGHT COMPANY
Major Future Additions or Retirements in 2013

Lansing Unit 3 was retired in the second quarter of 2013.

The Neal Unit 4 scrubber and baghouse project is estimated to be place in-service in the fourth quarter of 2013. The Neal 3 scrubber and baghouse project is estimated to be placed in-service in the second quarter of 2014.

Part 6: Summary of changes of estimated survivor curves, net salvage, and composite remaining life (excluding one year passage of time)

INTERSTATE POWER AND LIGHT COMPANY - IOWA
PROPOSED CHANGE IN ESTIMATED SURVIVOR CURVES AND COMPOSITE REMAINING LIFE

	ACCOUNT	PROPOSED SURVIVOR CURVE		CURRENT SURVIVOR CURVE	PROPOSED COMPOSITE REMAINING LIFE	CURRENT COMPOSITE REMAINING LIFE	COMPOSITE REMAINING *Change*
	ELECTRIC PLANT						
	STEAM PRODUCTION PLANT						
311.00	STRUCTURES AND IMPROVEMENTS						
	Neal Unit 4	100-S2.5	*	100-S2.5	27.0	12.4	*14.6*
	Lansing Unit 4	100-S2.5	*	100-S2.5	24.1	25.1	*(1.0)*
	Louisa Unit 1	100-S2.5	*	100-S2.5	27.1	28.3	*(1.2)*
	Clinton Unit 2	100-S2.5	*	100-S2.5	11.5	12.5	*(1.0)*
	Lansing Unit 3	100-S2.5	*	100-S2.5	-	-	-
	Lansing Units 3 & 4	100-S2.5	*	100-S2.5	24.5	25.5	*(1.0)*
	Burlington Station	100-S2.5	*	100-S2.5	11.5	12.5	*(1.0)*
	Neal Unit 3	100-S2.5	*	100-S2.5	22.1	15.4	*6.7*
	Ottumwa	100-S2.5	*	100-S2.5	21.3	22.2	*(0.9)*
	Prairie Creek Unit 4	100-S2.5	*	100-S2.5	22.5	23.5	*(1.0)*
	Prairie Creek Units 1 - 4	100-S2.5	*	100-S2.5	22.4	23.4	*(1.0)*
	Sutherland 3	100-S2.5	*	100-S2.5	11.5	12.5	*(1.0)*
	Sutherland 1 - 3	100-S2.5	*	100-S2.5	11.5	12.5	*(1.0)*
312.00	BOILER PLANT EQUIPMENT						
	Neal Unit 4	75-R2	*	75-R2	25.6	12.2	*13.4*
	Lansing Unit 4	75-R2	*	75-R2	23.7	24.7	*(1.0)*
	Louisa Unit 1	75-R2	*	75-R2	26.3	26.7	*(0.4)*
	Clinton Unit 2 (ML KAPP)	75-R2	*	75-R2	11.3	12.3	*(1.0)*
	Lansing Unit 3	75-R2	*	75-R2	-	-	-
	Lansing Units 3 & 4	75-R2	*	75-R2	23.8	24.7	*(0.9)*
	Burlington Station	75-R2	*	75-R2	11.3	12.3	*(1.0)*
	Neal Unit 3	75-R2	*	75-R2	21.5	15.0	*6.5*
	Ottumwa	75-R2	*	75-R2	20.6	21.5	*(0.9)*
	Prairie Creek Unit 4	75-R2	*	75-R2	21.9	22.8	*(0.9)*
	Prairie Creek Units 1, 2 & 3	75-R2	*	75-R2	21.9	22.9	*(1.0)*
	Prairie Creek Units 1 - 4	75-R2	*	75-R2	22.0	23.0	*(1.0)*
	Sutherland 1	75-R2	*	75-R2	1.5	2.5	*(1.0)*
	Sutherland 3	75-R2	*	75-R2	11.3	12.3	*(1.0)*
	Sutherland 1 & 3	75-R2	*	75-R2	11.4	12.3	*(0.9)*
312.10	BOILER PLANT EQUIPMENT - UNIT TRAIN						
	Prairie Creek Units 1 - 4	25-R2		25-R2	21.9	22.8	*(0.9)*
	Sutherland 1 - 3	25-R2		25-R2	21.0	21.9	*(0.9)*
312.50	BOILER PLANT EQUIPMENT - COMBUSTION INITIATIVE						
	Lansing Unit 4	10-SQ		10-SQ	2.2	3.2	*(1.0)*
	Clinton Unit 2 (ML KAPP)	10-SQ		10-SQ	4.2	4.7	*(0.5)*
	Burlington Station	10-SQ		10-SQ	1.5	2.5	*(1.0)*
	Ottumwa	10-SQ		10-SQ	4.7	5.7	*(1.0)*
	Prairie Creek Unit 4	10-SQ		10-SQ	1.5	-	*1.5*
	Prairie Creek Units 1, 2 & 3	10-SQ		10-SQ	6.6	7.6	*(1.0)*
	Sutherland 3	75-R2	*	75-R2	11.4	12.4	*(1.0)*

INTERSTATE POWER AND LIGHT COMPANY - IOWA
PROPOSED CHANGE IN ESTIMATED SURVIVOR CURVES AND COMPOSITE REMAINING LIFE

	ACCOUNT	PROPOSED SURVIVOR CURVE		CURRENT SURVIVOR CURVE	PROPOSED COMPOSITE REMAINING LIFE	CURRENT COMPOSITE REMAINING LIFE	COMPOSITE REMAINING *Change*
314.00	TURBOGENERATOR UNITS						
	Neal Unit 4	70-R2.5	*	70-R2.5	25.7	12.2	*13.5*
	Lansing Unit 4	70-R2.5	*	70-R2.5	23.4	24.3	*(0.9)*
	Louisa Unit 1	70-R2.5	*	70-R2.5	26.2	27.2	*(1.0)*
	Clinton Unit 2 (ML KAPP)	70-R2.5	*	70-R2.5	11.4	12.4	*(1.0)*
	Lansing Unit 3	70-R2.5	*	70-R2.5	-	-	-
	Lansing Units 3 & 4	70-R2.5	*	70-R2.5	24.0	24.9	*(0.9)*
	Burlington Station	70-R2.5	*	70-R2.5	11.3	12.3	*(1.0)*
	Neal Unit 3	70-R2.5	*	70-R2.5	21.6	15.1	*6.5*
	Ottumwa	70-R2.5	*	70-R2.5	20.6	21.5	*(0.9)*
	Prairie Creek Unit 4	70-R2.5	*	70-R2.5	22.1	23.1	*(1.0)*
	Prairie Creek Units 1, 2 & 3	70-R2.5	*	70-R2.5	21.9	22.9	*(1.0)*
	Prairie Creek Units 1 - 4	70-R2.5	*	70-R2.5	22.1	23.1	*(1.0)*
	Sutherland 1	70-R2.5	*	70-R2.5	1.5	2.5	*(1.0)*
	Sutherland 3	70-R2.5	*	70-R2.5	11.4	12.4	*(1.0)*
	Sutherland 1 & 3	70-R2.5	*	70-R2.5	11.4	12.4	*(1.0)*
315.00	ACCESSORY ELECTRIC EQUIPMENT						
	Neal Unit 4	70-R3	*	70-R3	25.5	12.2	*13.3*
	Lansing Unit 4	70-R3	*	70-R3	23.0	24.2	*(1.2)*
	Louisa Unit 1	70-R3	*	70-R3	26.1	27.0	*(0.9)*
	Clinton Unit 2 (ML KAPP)	70-R3	*	70-R3	11.4	12.4	*(1.0)*
	Lansing Unit 3	70-R3	*	70-R3	-	-	-
	Lansing Units 3 & 4	70-R3	*	70-R3	23.0	23.9	*(0.9)*
	Burlington Station	70-R3	*	70-R3	11.4	12.4	*(1.0)*
	Neal Unit 3	70-R3	*	70-R3	21.9	15.3	*6.6*
	Ottumwa	70-R3	*	70-R3	20.6	21.6	*(1.0)*
	Prairie Creek Unit 4	70-R3	*	70-R3	22.3	23.3	*(1.0)*
	Prairie Creek Units 1, 2 & 3	70-R3	*	70-R3	22.3	23.3	*(1.0)*
	Prairie Creek Units 1 - 4	70-R3	*	70-R3	22.3	23.3	*(1.0)*
	Sutherland 1	70-R3	*	70-R3	1.5	2.5	*(1.0)*
	Sutherland 1 & 3	70-R3	*	70-R3	11.1	12.1	*(1.0)*
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT						
	Neal Unit 4	60-R2	*	60-R2	25.1	12.1	*13.0*
	Lansing Unit 4	60-R2	*	60-R2	23.1	24.0	*(0.9)*
	Louisa Unit 1	60-R2	*	60-R2	25.8	26.7	*(0.9)*
	Clinton Unit 2 (ML KAPP)	60-R2	*	60-R2	11.3	12.3	*(1.0)*
	Lansing Unit 3	60-R2	*	60-R2	-	-	-
	Lansing Units 3 & 4	60-R2	*	60-R2	23.5	24.4	*(0.9)*
	Burlington Station	60-R2	*	60-R2	11.2	12.2	*(1.0)*
	Neal Unit 3	60-R2	*	60-R2	21.6	15.1	*6.5*
	Ottumwa	60-R2	*	60-R2	20.2	21.2	*(1.0)*
	Prairie Creek Unit 4	60-R2	*	60-R2	21.7	22.7	*(1.0)*
	Prairie Creek Units 1, 2 & 3	60-R2	*	60-R2	21.0	22.0	*(1.0)*
	Prairie Creek Units 1 - 4	60-R2	*	60-R2	21.7	22.7	*(1.0)*
	Sutherland 1 & 3	60-R2	*	60-R2	11.3	12.2	*(0.9)*

INTERSTATE POWER AND LIGHT COMPANY - IOWA
PROPOSED CHANGE IN ESTIMATED SURVIVOR CURVES AND COMPOSITE REMAINING LIFE

	ACCOUNT	PROPOSED SURVIVOR CURVE		CURRENT SURVIVOR CURVE	PROPOSED COMPOSITE REMAINING LIFE	CURRENT COMPOSITE REMAINING LIFE	COMPOSITE REMAINING *Change*
	OTHER PRODUCTION PLANT						
341.00	STRUCTURES AND IMPROVEMENTS						
	Dubuque (Diesel)	50-S2	*	50-S2	1.4	6.4	*(5.0)*
	Lansing (Diesel)	50-S2	*	50-S2	-	1.0	*(1.0)*
	Lime Creek	50-S2	*	50-S2	16.9	17.8	*(0.9)*
	Dubuque Unit 3 & 4	50-S2	*	100-S2.5	1.5	2.5	*(1.0)*
	Burlington CT Units 1 - 4	50-S2	*	50-S2	5.5	6.5	*(1.0)*
	Centerville CT Unit 1	50-S2	*	50-S2	1.5	2.5	*(1.0)*
	Centerville CT Unit 2	50-S2	*	50-S2	1.5	2.5	*(1.0)*
	Centerville CT Unit 1 & 2	50-S2	*	50-S2	1.5	2.5	*(1.0)*
	Emery	50-S2	*	50-S2	18.1	19.1	*(1.0)*
	Grinnell Combustion Turbine	50-S2	*	50-S2	2.5	3.5	*(1.0)*
	Sutherland CT Units 1 - 3	50-S2	*	50-S2	4.3	5.2	*(0.9)*
	Marshalltown Station	50-S2	*	50-S2	-	-	-
	Red Cedar Cogeneration Station	50-S2	*	50-S2	13.4	14.4	*(1.0)*
	Whispering Willow	SQUARE	*	SQUARE	22.0	23.0	*(1.0)*
342.00	OIL SYSTEM						
	Dubuque (Diesel)	55-R2.5	*	55-R2.5	1.5	6.8	*(5.3)*
	Lansing (Diesel)	55-R2.5	*	55-R2.5	-	1.0	*(1.0)*
	Lime Creek	55-R2.5	*	55-R2.5	17.3	18.2	*(0.9)*
	Burlington CT Units 1 - 4	55-R2.5	*	55-R2.5	5.5	6.4	*(0.9)*
	Centerville CT Unit 1 & 2	55-R2.5	*	55-R2.5	1.5	2.5	*(1.0)*
	Emery	55-R2.5	*	55-R2.5	18.0	19.0	*(1.0)*
	Centerville (Diesel)	55-R2.5	*	55-R2.5	1.5	2.4	*(0.9)*
	Grinnell Combustion Turbine	55-R2.5	*	55-R2.5	2.5	3.5	*(1.0)*
	Sutherland CT Units 1 - 3	55-R2.5	*	55-R2.5	4.5	5.5	*(1.0)*
	Marshalltown Station	55-R2.5	*	55-R2.5	-	-	-
343.00	ENGINES						
	Dubuque (Diesel)	43-S2	*	43-S2	1.4	5.8	*(4.4)*
	Lansing (Diesel)	43-S2	*	43-S2	-	1.0	*(1.0)*
	Lime Creek	43-S2	*	43-S2	15.6	16.4	*(0.8)*
	Dubuque Unit 3 & 4	43-S2	*	75-R2	1.5	2.5	*(1.0)*
	Burlington CT Unit 2	43-S2	*	43-S2	5.5	6.5	*(1.0)*
	Burlington CT Units 1 - 4	43-S2	*	43-S2	5.5	6.5	*(1.0)*
	Centerville CT Unit 1	43-S2	*	43-S2	1.5	2.5	*(1.0)*
	Centerville CT Unit 1 & 2	43-S2	*	43-S2	1.5	2.5	*(1.0)*
	Emery	43-S2	*	43-S2	17.8	18.8	*(1.0)*
	Centerville (Diesel)	43-S2	*	43-S2	1.5	2.5	*(1.0)*
	Grinnell Combustion Turbine	43-S2	*	43-S2	2.5	3.5	*(1.0)*
	Marshalltown Station	43-S2	*	43-S2	-	-	-
344.00	GENERATORS						
	Dubuque (Diesel)	50-R3	*	50-R3	1.4	6.4	*(5.0)*
	Lansing (Diesel)	50-R3	*	50-R3	-	1.0	*(1.0)*
	Lime Creek	50-R3	*	50-R3	17.2	18.0	*(0.8)*
	Dubuque Unit 3 & 4	50-R3	*	70-R2.5	1.5	2.5	*(1.0)*
	Burlington CT Unit 1	50-R3	*	50-R3	5.5	6.5	*(1.0)*
	Burlington CT Unit 2	50-R3	*	50-R3	5.5	6.5	*(1.0)*
	Burlington CT Unit 3	50-R3	*	50-R3	5.5	6.5	*(1.0)*
	Burlington CT Unit 4	50-R3	*	50-R3	5.5	6.5	*(1.0)*
	Burlington CT Units 1 - 4	50-R3	*	50-R3	5.4	6.4	*(1.0)*
	Centerville CT Unit 1	50-R3	*	50-R3	1.5	-	*1.5*
	Centerville CT Unit 2	50-R3	*	50-R3	1.5	-	*1.5*
	Centerville CT Unit 1 & 2	50-R3	*	50-R3	1.5	2.5	*(1.0)*
	Emery	50-R3	*	50-R3	18.1	19.1	*(1.0)*
	Centerville (Diesel)	50-R3	*	50-R3	1.4	2.4	*(1.0)*
	Grinnell Combustion Turbine	50-R3	*	50-R3	2.5	3.5	*(1.0)*
	Sutherland CT Unit 1	50-R3	*	50-R3	4.4	5.3	*(0.9)*
	Sutherland CT Unit 2	50-R3	*	50-R3	4.3	5.3	*(1.0)*
	Sutherland CT Unit 3	50-R3	*	50-R3	4.4	5.4	*(1.0)*
	Sutherland CT Units 1 - 3	50-R3	*	50-R3	4.5	5.5	*(1.0)*
	Red Cedar Cogeneration Station	50-R3	*	50-R3	13.1	14.1	*(1.0)*
	Whispering Willow	40-S2.5	*	40-S2.5	21.5	22.5	*(1.0)*
345.00	ACCESSORY ELECTRIC EQUIPMENT						

INTERSTATE POWER AND LIGHT COMPANY - IOWA
PROPOSED CHANGE IN ESTIMATED SURVIVOR CURVES AND COMPOSITE REMAINING LIFE

	ACCOUNT	PROPOSED SURVIVOR CURVE		CURRENT SURVIVOR CURVE	PROPOSED COMPOSITE REMAINING LIFE	CURRENT COMPOSITE REMAINING LIFE	COMPOSITE REMAINING *Change*
	Dubuque (Diesel)	40-S1	*	40-S1	1.5	7.2	*(5.7)*
	Lansing (Diesel)	40-S1	*	40-S1	0.0	1.0	*(1.0)*
	Lime Creek	40-S1	*	40-S1	15.2	15.6	*(0.4)*
	Dubuque Unit 3 & 4	40-S1	*	70-R3	1.5	2.5	*(1.0)*
	Burlington CT Units 1 - 4	40-S1	*	40-S1	5.3	6.2	*(0.9)*
	Centerville CT Unit 2	40-S1	*	40-S1	1.5	2.5	*(1.0)*
	Centerville CT Unit 1 & 2	40-S1	*	40-S1	1.5	2.5	*(1.0)*
	Emery	40-S1	*	40-S1	17.1	18.1	*(1.0)*
	Centerville (Diesel)	40-S1	*	40-S1	1.4	2.3	*(0.9)*
	Grinnell Combustion Turbine	40-S1	*	40-S1	2.5	3.5	*(1.0)*
	Sutherland CT Units 1 - 3	40-S1	*	40-S1	4.5	5.5	*(1.0)*
	Marshalltown Station	40-S1	*	40-S1	-	-	-
	Whispering Willow	30-R2.5	*	30-R2.5	20.1	21.0	*(0.9)*
346.00	MISCELLANEOUS PLANT EQUIPMENT						
	Dubuque (Diesel)	40-R2	*	40-R2	1.4	5.7	*(4.3)*
	Lime Creek	40-R2	*	40-R2	17.1	18.3	*(1.2)*
	Dubuque Unit 3 & 4	40-R2	*	60-R2	1.5	2.5	*(1.0)*
	Burlington CT Units 1 - 4	40-R2	*	40-R2	5.3	6.3	*(1.0)*
	Centerville CT Unit 1 & 2	40-R2	*	40-R2	1.5	2.5	*(1.0)*
	Emery	40-R2	*	40-R2	17.3	18.2	*(0.9)*
	Centerville (Diesel)	40-R2	*	40-R2	1.4	2.3	*(0.9)*
	Grinnell Combustion Turbine	40-R2	*	40-R2	2.5	3.4	*(0.9)*
	Marshalltown Station	40-R2	*	40-R2	-	-	-
	Red Cedar Cogeneration Station	40-R2	*	40-R2	13.0	13.9	*(0.9)*
	Whispering Willow	40-R2		40-R2	20.6	21.7	*(1.1)*
	DISTRIBUTION PLANT						
361.00	STRUCTURES AND IMPROVEMENTS	53-R2.5		53-R2.5	44.7	44.6	*0.1*
362.00	STATION EQUIPMENT	48-R2.5		48-R2.5	38.4	38.5	*(0.1)*
362.40	STATION EQUIPMENT - SYSTEM CONTROL CENTER	10-S4		10-S4	3.0	3.4	*(0.4)*
364.00	POLES, TOWERS AND FIXTURES	50-R3		50-R3	38.6	38.6	-
365.00	OVERHEAD CONDUCTORS AND DEVICES	55-R3		55-R3	42.4	42.7	*(0.3)*
366.00	UNDERGROUND CONDUIT	70-R4		70-R4	56.2	56.1	*0.1*
367.00	UNDERGROUND CONDUCTORS AND DEVICES	48-R3		48-R3	37.9	38.0	*(0.1)*
368.00	LINE TRANSFORMERS	45-R3		45-R3	34.8	35.2	*(0.4)*
369.00	SERVICES	43-R2		43-R2	33.1	33.2	*(0.1)*
370.00	METERS	36-R1		36-R1	25.2	25.6	*(0.4)*
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	30-R1.5		30-R1.5	20.0	20.1	*(0.1)*
	GENERAL PLANT						
390.00	STRUCTURES AND IMPROVEMENTS	45-R2.5		45-R2.5	33.9	34.9	*(1.0)*
391.00	OFFICE FURNITURE AND EQUIPMENT	20-SQ		20-SQ	10.2	10.6	*(0.4)*
391.40	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS	5-SQ		5-SQ	2.4	2.8	*(0.4)*
392.00	TRANSPORTATION EQUIPMENT	18-L1.5		18-L1.5	12.1	12.6	*(0.5)*
393.00	STORES EQUIPMENT	25-SQ		25-SQ	5.4	6.5	*(1.1)*
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ		25-SQ	16.8	17.3	*(0.5)*
395.00	LABORATORY EQUIPMENT	15-SQ		15-SQ	1.5	2.0	*(0.5)*
396.00	POWER OPERATED EQUIPMENT	18-L2.5		18-L2.5	10.0	10.1	*(0.1)*
397.00	COMMUNICATION EQUIPMENT						
	ELECTRONIC	12-SQ		12-SQ	7.0	7.3	*(0.3)*
	TOWER/BUILDING	25-SQ		25-SQ	12.1	11.1	*1.0*

INTERSTATE POWER AND LIGHT COMPANY - IOWA
PROPOSED CHANGE IN ESTIMATED SURVIVOR CURVES AND COMPOSITE REMAINING LIFE

	ACCOUNT	PROPOSED SURVIVOR CURVE	CURRENT SURVIVOR CURVE	PROPOSED COMPOSITE REMAINING LIFE	CURRENT COMPOSITE REMAINING LIFE	COMPOSITE REMAINING *Change*
	GAS PLANT					
	TRANSMISSION PLANT					
366.00	STRUCTURES AND IMPROVEMENTS	65-R4	65-R4	54.2	55.3	*(1.1)*
367.00	MAINS	60-R3	60-R3	43.0	43.7	*(0.7)*
369.00	MEASURING AND REGULATING STATION EQUIPMENT	35-R2.5	35-R2.5	28.0	27.5	*0.5*
	TOTAL TRANSMISSION PLANT					
	DISTRIBUTION PLANT					
375.00	STRUCTURES AND IMPROVEMENTS	50-R1	50-R1	41.0	38.1	*2.9*
376.00	MAINS	53-R1.5	53-R1.5	40.1	40.4	*(0.3)*
378.00	MEASURING AND REGULATING STATION EQUIPMENT	35-L2	35-L2	24.3	25.6	*(1.3)*
379.00	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	35-S0	35-S0	29.2	26.4	*2.8*
380.00	SERVICES	41-R1.5	41-R1.5	30.0	29.1	*0.9*
381.00	METERS	22-O1	22-O1	15.6	15.7	*(0.1)*
382.00	METER INSTALLATIONS	41-R1.5	41-R1.5	25.8	29.1	*(3.3)*
383.00	HOUSE REGULATORS	41-R3	41-R3	27.9	28.0	*(0.1)*
385.00	IND. MEASURING AND REGULATING STATION EQUIPMENT	32-R2	32-R2	16.7	17.3	*(0.6)*
387.00	OTHER EQUIPMENT	25-R4	25-R4	5.6	6.2	*(0.6)*
	GENERAL PLANT					
390.00	STRUCTURES AND IMPROVEMENTS	42-R1.5	42-R1.5	26.0	26.5	*(0.5)*
391.00	OFFICE FURNITURE AND EQUIPMENT	20-SQ	20-SQ	4.4	5.6	*(1.2)*
392.00	TRANSPORTATION EQUIPMENT	11-S3	11-S3	4.8	5.5	*(0.7)*
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	25-SQ	15.7	16.0	*(0.3)*
395.00	LABORATORY EQUIPMENT	15-SQ	15-SQ	2.5	2.8	*(0.3)*
396.00	POWER OPERATED EQUIPMENT	19-S1.5	19-S1.5	8.0	8.5	*(0.5)*
397.00	COMMUNICATION EQUIPMENT	12-SQ	12-SQ	4.6	4.3	*0.3*
	COMMON PLANT					
390.00	STRUCTURES AND IMPROVEMENTS	50-R3	50-R3	43.1	43.6	*(0.5)*
391.00	OFFICE FURNITURE AND EQUIPMENT	20-SQ	20-SQ	15.2	16.6	*(1.4)*
391.40	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS	5-SQ	5-SQ	2.2	2.5	*(0.3)*
392.00	TRANSPORTATION EQUIPMENT	12-L3	12-L3	6.6	6.4	*0.2*
393.00	STORES EQUIPMENT	25-SQ	25-SQ	4.5	-	*4.5*
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	25-SQ	16.2	16.6	*(0.4)*
396.00	POWER OPERATED EQUIPMENT	18-L3	18-L3	11.7	12.0	*(0.3)*
397.00	COMMUNICATION EQUIPMENT					
	ELECTRONIC	12-SQ	12-SQ	7.2	7.8	*(0.6)*
	TOWER/BUILDING	25-SQ	25-SQ	19.8	21.4	*(1.6)*
397.40	COMMUNICATION EQUIPMENT - IDEN					
	ELECTRONIC	10-SQ	10-SQ	1.7	2.4	*(0.7)*
	TOWER/BUILDING	25-SQ	25-SQ	16.7	17.7	*(1.0)*
398.00	MISCELLANEOUS EQUIPMENT	10-SQ	10-SQ	2.5	3.5	*(1.0)*

INTERSTATE POWER AND LIGHT COMPANY - MINNESOTA
PROPOSED CHANGE IN ESTIMATED SURVIVOR CURVES AND COMPOSITE REMAINING LIFE

	ACCOUNT	PROPOSED SURVIVOR CURVE		CURRENT SURVIVOR CURVE	PROPOSED COMPOSITE REMAINING LIFE	CURRENT COMPOSITE REMAINING LIFE	COMPOSITE REMAINING *Change*
	ELECTRIC PLANT						
	STEAM PRODUCTION PLANT						
311.00	STRUCTURES AND IMPROVEMENTS						
	Fox Lake Unit 1	100-S2	*	100-S2	-	-	-
	Fox Lake Unit 3	100-S2	*	100-S2	4.5	5.5	(1.0)
	Fox Lake Units 1 & 3	100-S2	*	100-S2	4.5	5.5	(1.0)
312.00	BOILER PLANT EQUIPMENT						
	Fox Lake Unit 1	75-S2	*	75-S2	-	-	-
	Fox Lake Unit 3	75-S2	*	75-S2	4.5	5.5	(1.0)
	Fox Lake Units 1 & 3	75-S2	*	75-S2	4.5	5.5	(1.0)
314.00	TURBOGENERATOR UNITS						
	Fox Lake Unit 1	75-S3	*	75-S3	-	-	-
	Fox Lake Unit 3	75-S3	*	75-S3	4.5	5.4	(0.9)
	Fox Lake Units 1 & 3	75-S3	*	75-S3	4.5	5.5	(1.0)
315.00	ACCESSORY ELECTRIC EQUIPMENT						
	Fox Lake Unit 1	65-R4	*	65-R4	-	-	-
	Fox Lake Unit 3	65-R4	*	65-R4	4.5	5.5	(1.0)
	Fox Lake Units 1 & 3	65-R4	*	65-R4	4.5	5.5	(1.0)
316.00	MISCELLANEOUS PLANT EQUIPMENT						
	Fox Lake Unit 1	60-S1.5	*	60-S1.5	-	-	-
	Fox Lake Unit 3	60-S1.5	*	60-S1.5	4.5	5.5	(1.0)
	Fox Lake Units 1 & 3	60-S1.5	*	60-S1.5	4.5	5.5	(1.0)
	OTHER PRODUCTION PLANT						
342.00	OIL SYSTEM						
	Hills	50-S0.5	*	50-S0.5	-	-	-
343.00	ENGINES						
	Hills	40-L4	*	40-L4	3.5	4.5	(1.0)
344.00	GENERATORS						
	Hills	60-S2.5	*	60-S2.5	3.5	4.5	(1.0)
345.00	ACCESSORY ELECTRIC EQUIPMENT						
	Hills	30-R1.5	*	30-R1.5	3.4	4.3	(0.9)
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT						
	Hills	30-R4	*	30-R4	-	-	-
	DISTRIBUTION PLANT						
361.00	STRUCTURES AND IMPROVEMENTS	50-R2.5		50-R2.5	40.4	40.7	(0.3)
362.00	STATION EQUIPMENT	25-O1		25-O1	20.9	20.3	0.6
364.00	POLES, TOWERS AND FIXTURES	47-R1		47-R1	38.2	38.1	0.1
365.00	OVERHEAD CONDUCTORS AND DEVICES	42-R1		42-R1	32.5	32.7	(0.2)
366.00	UNDERGROUND CONDUIT	40-R3		40-R3	28.3	28.8	(0.5)
367.00	UNDERGROUND CONDUCTORS AND DEVICES	42-R2		42-R2	32.3	32.6	(0.3)
368.00	LINE TRANSFORMERS	39-R1		39-R1	31.1	31.0	0.1
369.00	SERVICES	40-O1		40-O1	34.8	35.0	(0.2)
370.00	METERS	43-R1.5		43-R1.5	18.5	18.2	0.3
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	23-L1		23-L1	16.1	16.0	0.1
	GENERAL PLANT						
390.00	STRUCTURES AND IMPROVEMENTS	50-S3		50-S3	40.7	41.1	(0.4)
391.10	OFFICE FURNITURE AND EQUIPMENT - EXCEPT COMPUTERS	20-SQ		20-SQ	13.7	5.1	8.6
391.40	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS	5-SQ		5-SQ	1.8	2.8	(1.0)

INTERSTATE POWER AND LIGHT COMPANY - MINNESOTA
PROPOSED CHANGE IN ESTIMATED SURVIVOR CURVES AND COMPOSITE REMAINING LIFE

ACCOUNT		PROPOSED SURVIVOR CURVE	CURRENT SURVIVOR CURVE	PROPOSED COMPOSITE REMAINING LIFE	CURRENT COMPOSITE REMAINING LIFE	COMPOSITE REMAINING *Change*
392.00	TRANSPORTATION EQUIPMENT - TRUCKS, TRAILERS AND VANS	13-L3	13-L3	6.3	6.8	(0.5)
393.00	STORES EQUIPMENT	25-SQ	25-SQ	7.0	8.0	(1.0)
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	25-SQ	16.3	16.9	(0.6)
395.00	LABORATORY EQUIPMENT	15-SQ	15-SQ	1.5	2.5	(1.0)
396.00	POWER OPERATED EQUIPMENT	13-L3	13-L3	4.3	4.5	(0.2)
397.00	COMMUNICATION EQUIPMENT					
	ELECTRONIC	12-SQ	12-SQ	5.9	6.8	(0.9)
	TOWER/BUILDING	25-SQ	25-SQ	14.3	15.3	(1.0)
	GAS PLANT					
	DISTRIBUTION PLANT					
375.00	STRUCTURES AND IMPROVEMENTS	40-S1	40-S1	37.5	19.9	17.6
376.00	MAINS	56-S2	56-S2	40.0	40.4	(0.4)
378.00	MEASURING AND REGULATING EQUIPMENT - GENERAL	32-S1.5	32-S1.5	19.1	19.7	(0.6)
379.00	MEASURING AND REGULATING EQUIPMENT - CITY GATE	16-S2.5	16-S2.5	11.3	11.9	(0.6)
380.10	SERVICES	38-R4	38-R4	21.6	22.5	(0.9)
381.00	METERS	28-R2	28-R2	17.6	16.4	1.2
382.00	METER INSTALLATIONS	38-R4	38-R4	23.7	22.5	1.2
383.00	HOUSE REGULATORS	32-L3	32-L3	13.9	14.2	(0.3)
385.00	IND. MEASURING AND REGULATING STATION EQUIPMENT	15-S0.5	15-S0.5	4.6	4.7	(0.1)
	GENERAL PLANT					
390.00	STRUCTURES AND IMPROVEMENTS	30-S3	30-S3	16.7	17.6	(0.9)
392.20	TRANSPORTATION EQUIPMENT-TRUCKS	11-L4	11-L4	3.9	4.5	(0.6)
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	25-SQ	9.0	8.5	0.5
395.00	LABORATORY EQUIPMENT	15-SQ	15-SQ	2.5	3.5	(1.0)
	COMMON PLANT					
390.00	STRUCTURES AND IMPROVEMENTS	50-R3	50-R3	43.3	44.3	(1.0)
391.00	OFFICE FURNITURE AND EQUIPMENT					
	EXCEPT COMPUTERS	20-SQ	20-SQ	9.2	10.2	(1.0)
	COMPUTERS	5-SQ	5-SQ	2.5	3.5	(1.0)
392.00	TRANSPORTATION EQUIPMENT					
	TRUCKS, TRAILERS AND VANS	12-S3	12-S3	5.5	5.4	0.1
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	25-SQ	25-SQ	18.3	19.3	(1.0)
396.00	POWER OPERATED EQUIPMENT	12-L2.5	12-L2.5	5.3	5.5	(0.2)
397.00	COMMUNICATION EQUIPMENT					
	ELECTRONIC	12-SQ	12-SQ	6.0	7.1	(1.1)
	TOWER/BUILDING	25-SQ	25-SQ	19.2	20.3	(1.1)
397.40	COMMUNICATION EQUIPMENT - IDEN					
	ELECTRONIC	10-SQ	10-SQ	1.7	2.5	(0.8)
	TOWER/BUILDING	25-SQ	25-SQ	17.4	18.4	(1.0)

INTERSTATE POWER AND LIGHT COMPANY - IOWA
PROPOSED CHANGE IN NET SALVAGE

	ACCOUNT	PROPOSED NET SALVAGE PERCENT	CURRENT NET SALVAGE PERCENT
	ELECTRIC PLANT		
	STEAM PRODUCTION PLANT		
311.00	STRUCTURES AND IMPROVEMENTS		
	Neal Unit 4	(30)	(30)
	Lansing Unit 4	(30)	(30)
	Louisa Unit 1	(30)	(30)
	Clinton Unit 2 (ML KAPP)	(30)	(30)
	Lansing Unit 3	(30)	(30)
	Lansing Units 3 & 4	(30)	(30)
	Burlington Station	(30)	(30)
	Neal Unit 3	(30)	(30)
	Ottumwa	(30)	(30)
	Prairie Creek Unit 4	(30)	(30)
	Prairie Creek Units 1, 2 & 3	(30)	(30)
	Prairie Creek Units 1 - 4	(30)	(30)
	Sutherland 3	(30)	(30)
	Sutherland 1 & 3	(30)	(30)
312.00	BOILER PLANT EQUIPMENT		
	Neal Unit 4	(20)	(20)
	Lansing Unit 4	(20)	(20)
	Louisa Unit 1	(20)	(20)
	Clinton Unit 2 (ML KAPP)	(20)	(20)
	Lansing Unit 3	(20)	(20)
	Lansing Units 3 & 4	(20)	(20)
	Burlington Station	(20)	(20)
	Neal Unit 3	(20)	(20)
	Ottumwa	(20)	(20)
	Prairie Creek Unit 4	(20)	(20)
	Prairie Creek Units 1, 2 & 3	(20)	(20)
	Prairie Creek Units 1 - 4	(20)	(20)
	Sutherland 1	(20)	(20)
	Sutherland 3	(20)	(20)
	Sutherland 1 & 3	(20)	(20)
312.10	BOILER PLANT EQUIPMENT - UNIT TRAIN		
	Prairie Creek Unit 4	20	20
	Sutherland 1 & 3	20	20

INTERSTATE POWER AND LIGHT COMPANY - IOWA
PROPOSED CHANGE IN NET SALVAGE

	ACCOUNT	PROPOSED NET SALVAGE PERCENT	CURRENT NET SALVAGE PERCENT
312.50	BOILER PLANT EQUIPMENT - COMBUSTION INITIATIVE		
	Lansing Unit 4	0	0
	Clinton Unit 2 (ML KAPP)	0	0
	Burlington Station	0	0
	Ottumwa	0	0
	Prairie Creek Unit 4	0	0
	Prairie Creek Units 1, 2 & 3	0	0
	Sutherland 3	0	0
314.00	TURBOGENERATOR UNITS		
	Neal Unit 4	(10)	(10)
	Lansing Unit 4	(10)	(10)
	Louisa Unit 1	(10)	(10)
	Clinton Unit 2 (ML KAPP)	(10)	(10)
	Lansing Unit 3	(10)	(10)
	Lansing Units 3 & 4	(10)	(10)
	Burlington Station	(10)	(10)
	Neal Unit 3	(10)	(10)
	Ottumwa	(10)	(10)
	Prairie Creek Unit 4	(10)	(10)
	Prairie Creek Units 1, 2 & 3	(10)	(10)
	Prairie Creek Units 1 - 4	(10)	(10)
	Sutherland 1	(10)	(10)
	Sutherland 3	(10)	(10)
	Sutherland 1 & 3	(10)	(10)
315.00	ACCESSORY ELECTRIC EQUIPMENT		
	Neal Unit 4	(5)	(5)
	Lansing Unit 4	(5)	(5)
	Louisa Unit 1	(5)	(5)
	Clinton Unit 2 (ML KAPP)	(5)	(5)
	Lansing Unit 3	(5)	(5)
	Lansing Units 3 & 4	(5)	(5)
	Burlington Station	(5)	(5)
	Neal Unit 3	(5)	(5)
	Ottumwa	(5)	(5)
	Prairie Creek Unit 4	(5)	(5)
	Prairie Creek Units 1, 2 & 3	(5)	(5)
	Prairie Creek Units 1 - 4	(5)	(5)
	Sutherland 1	(5)	(5)
	Sutherland 1 & 3	(5)	(5)

INTERSTATE POWER AND LIGHT COMPANY - IOWA
PROPOSED CHANGE IN NET SALVAGE

ACCOUNT		PROPOSED NET SALVAGE PERCENT	CURRENT NET SALVAGE PERCENT
316.00	MISCELLANEOUS POWER PLANT EQUIPMENT		
	Neal Unit 4	(5)	(5)
	Lansing Unit 4	(5)	(5)
	Louisa Unit 1	(5)	(5)
	Clinton Unit 2 (ML KAPP)	(5)	(5)
	Lansing Unit 3	(5)	(5)
	Lansing Units 3 & 4	(5)	(5)
	Burlington Station	(5)	(5)
	Neal Unit 3	(5)	(5)
	Ottumwa	(5)	(5)
	Prairie Creek Unit 4	(5)	(5)
	Prairie Creek Units 1, 2 & 3	(5)	(5)
	Prairie Creek Units 1 - 4	(5)	(5)
	Sutherland 1 & 3	(5)	(5)
	OTHER PRODUCTION PLANT		
341.00	STRUCTURES AND IMPROVEMENTS		
	Dubuque (Diesel)	(3)	(3)
	Lansing (Diesel)	(3)	(3)
	Lime Creek	(3)	(3)
	Dubuque Unit 3 & 4	(3)	(30)
	Burlington CT Units 1 - 4	(3)	(3)
	Centerville CT Unit 1	(3)	(3)
	Centerville CT Unit 2	(3)	(3)
	Centerville CT Unit 1 & 2	(3)	(3)
	Emery	(3)	(3)
	Grinnell Combustion Turbine	(3)	(3)
	Sutherland CT Units 1 - 3	(3)	(3)
	Marshalltown Station	(3)	(3)
	Red Cedar Cogeneration Station	(3)	(3)
	Whispering Willow	0	0
342.00	OIL SYSTEM		
	Dubuque (Diesel)	(10)	(10)
	Lansing (Diesel)	(10)	(10)
	Lime Creek	(10)	(10)
	Burlington CT Units 1 - 4	(10)	(10)
	Centerville CT Unit 1 & 2	(10)	(10)
	Emery	(10)	(10)
	Centerville (Diesel)	(10)	(10)
	Grinnell Combustion Turbine	(10)	(10)
	Sutherland CT Units 1 - 3	(10)	(10)
	Marshalltown Station	(10)	(10)

INTERSTATE POWER AND LIGHT COMPANY - IOWA
PROPOSED CHANGE IN NET SALVAGE

	ACCOUNT	PROPOSED NET SALVAGE PERCENT	CURRENT NET SALVAGE PERCENT
343.00	ENGINES		
	Dubuque (Diesel)	(5)	(5)
	Lansing (Diesel)	(5)	(5)
	Lime Creek	(5)	(5)
	Dubuque Unit 3 & 4	(5)	(20)
	Burlington CT Unit 2	(5)	(5)
	Burlington CT Units 1 - 4	(5)	(5)
	Centerville CT Unit 1	(5)	(5)
	Centerville CT Unit 1 & 2	(5)	(5)
	Emery	(5)	(5)
	Centerville (Diesel)	(5)	(5)
	Grinnell Combustion Turbine	(5)	(5)
	Marshalltown Station	(5)	(5)
344.00	GENERATORS		
	Dubuque (Diesel)	(15)	(15)
	Lansing (Diesel)	(15)	(15)
	Lime Creek	(15)	(15)
	Dubuque Unit 3 & 4	(15)	(10)
	Burlington CT Unit 1	(15)	(15)
	Burlington CT Unit 2	(15)	(15)
	Burlington CT Unit 3	(15)	(15)
	Burlington CT Unit 4	(15)	(15)
	Burlington CT Units 1 - 4	(15)	(15)
	Centerville CT Unit 1	(15)	(10)
	Centerville CT Unit 2	(15)	(15)
	Centerville CT Unit 1 & 2	(15)	(15)
	Emery	(15)	(15)
	Centerville (Diesel)	(15)	(15)
	Grinnell Combustion Turbine	(15)	(15)
	Sutherland CT Unit 1	(15)	(15)
	Sutherland CT Unit 2	(15)	(15)
	Sutherland CT Unit 3	(15)	(15)
	Sutherland CT Units 1 - 3	(15)	(15)
	Red Cedar Cogeneration Station	(15)	(15)
	Whispering Willow	(5)	(5)

INTERSTATE POWER AND LIGHT COMPANY - IOWA
PROPOSED CHANGE IN NET SALVAGE

	ACCOUNT	PROPOSED NET SALVAGE PERCENT	CURRENT NET SALVAGE PERCENT
345.00	ACCESSORY ELECTRIC EQUIPMENT		
	Dubuque (Diesel)	0	0
	Lansing (Diesel)	0	0
	Lime Creek	0	0
	Dubuque Unit 3 & 4	0	(5)
	Burlington CT Units 1 - 4	0	0
	Centerville CT Unit 2	0	0
	Centerville CT Unit 1 & 2	0	0
	Emery	0	0
	Centerville (Diesel)	0	0
	Grinnell Combustion Turbine	0	0
	Sutherland CT Unit 1	0	0
	Sutherland CT Units 1 - 3	0	0
	Marshalltown Station	0	0
	Whispering Willow	0	0
346.00	MISCELLANEOUS PLANT EQUIPMENT		
	Dubuque (Diesel)	0	0
	Lime Creek	0	0
	Dubuque Unit 3 & 4	0	(5)
	Burlington CT Units 1 - 4	0	0
	Centerville CT Unit 1 & 2	0	0
	Emery	0	0
	Centerville (Diesel)	0	0
	Grinnell Combustion Turbine	0	0
	Marshalltown Station	0	0
	Red Cedar Cogeneration Station	0	0
	Whispering Willow	0	0
	DISTRIBUTION PLANT		
361.00	STRUCTURES AND IMPROVEMENTS	(20)	(20)
362.00	STATION EQUIPMENT	(5)	(5)
362.40	STATION EQUIPMENT - SYSTEM CONTROL CENTER	0	0
364.00	POLES, TOWERS AND FIXTURES	(60)	(60)
365.00	OVERHEAD CONDUCTORS AND DEVICES	(40)	(40)
366.00	UNDERGROUND CONDUIT	(25)	(25)
367.00	UNDERGROUND CONDUCTORS AND DEVICES	(10)	(10)
368.00	LINE TRANSFORMERS	(5)	(5)
369.00	SERVICES	(50)	(50)
370.00	METERS	0	0
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	(20)	(20)

INTERSTATE POWER AND LIGHT COMPANY - IOWA
PROPOSED CHANGE IN NET SALVAGE

	ACCOUNT	PROPOSED NET SALVAGE PERCENT	CURRENT NET SALVAGE PERCENT
	GENERAL PLANT		
390.00	STRUCTURES AND IMPROVEMENTS	(5)	(5)
391.00	OFFICE FURNITURE AND EQUIPMENT	0	0
391.40	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS	0	0
392.00	TRANSPORTATION EQUIPMENT	15	15
393.00	STORES EQUIPMENT	0	0
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	0	0
395.00	LABORATORY EQUIPMENT	0	0
396.00	POWER OPERATED EQUIPMENT	10	10
397.00	COMMUNICATION EQUIPMENT		
	ELECTRONIC	0	0
	TOWER/BUILDING	0	0
	GAS PLANT		
	TRANSMISSION PLANT		
366.00	STRUCTURES AND IMPROVEMENTS	(5)	(5)
367.00	MAINS	(20)	(20)
369.00	MEASURING AND REGULATING STATION EQUIPMENT	(5)	(5)
	DISTRIBUTION PLANT		
375.00	STRUCTURES AND IMPROVEMENTS	(10)	(10)
376.00	MAINS	(35)	(35)
378.00	MEASURING AND REGULATING STATION EQUIPMENT	(10)	(10)
379.00	MEASURING AND REGULATING STATION EQUIPMENT - CITY GATE	(10)	(10)
380.00	SERVICES	(70)	(70)
381.00	METERS	(20)	(20)
382.00	METER INSTALLATIONS	(70)	(70)
383.00	HOUSE REGULATORS	(15)	(15)
385.00	IND. MEASURING AND REGULATING STATION EQUIPMENT	(5)	(5)
387.00	OTHER EQUIPMENT	(5)	(5)

INTERSTATE POWER AND LIGHT COMPANY - IOWA
PROPOSED CHANGE IN NET SALVAGE

	ACCOUNT	PROPOSED NET SALVAGE PERCENT	CURRENT NET SALVAGE PERCENT
	GENERAL PLANT		
390.00	STRUCTURES AND IMPROVEMENTS	(10)	(10)
391.00	OFFICE FURNITURE AND EQUIPMENT	0	0
392.00	TRANSPORTATION EQUIPMENT	10	10
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	0	0
395.00	LABORATORY EQUIPMENT	0	0
396.00	POWER OPERATED EQUIPMENT	10	10
397.00	COMMUNICATION EQUIPMENT	0	0
	COMMON PLANT		
390.00	STRUCTURES AND IMPROVEMENTS	(5)	(5)
391.00	OFFICE FURNITURE AND EQUIPMENT	0	0
391.40	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS	0	0
392.00	TRANSPORTATION EQUIPMENT	20	20
393.00	STORES EQUIPMENT	0	0
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	0	0
396.00	POWER OPERATED EQUIPMENT	20	20
397.00	COMMUNICATION EQUIPMENT		
	ELECTRONIC	0	0
	TOWER/BUILDING	0	0
397.40	COMMUNICATION EQUIPMENT - IDEN		
	ELECTRONIC	0	0
	TOWER/BUILDING	0	0
398.00	MISCELLANEOUS EQUIPMENT	0	0
	TOTAL COMMON PLANT		

INTERSTATE POWER AND LIGHT COMPANY - MINNESOTA
PROPOSED CHANGE IN NET SALVAGE

	ACCOUNT	PROPOSED NET SALVAGE PERCENT	CURRENT NET SALVAGE PERCENT
	ELECTRIC PLANT		
	STEAM PRODUCTION PLANT		
311.00	STRUCTURES AND IMPROVEMENTS		
	Fox Lake Unit 1	(20)	(20)
	Fox Lake Unit 3	(20)	(20)
	Fox Lake Units 1 & 3	(20)	(20)
312.00	BOILER PLANT EQUIPMENT		
	Fox Lake Unit 1	(20)	(20)
	Fox Lake Unit 3	(20)	(20)
	Fox Lake Units 1 & 3	(20)	(20)
314.00	TURBOGENERATOR UNITS		
	Fox Lake Unit 1	(10)	(10)
	Fox Lake Unit 3	(10)	(10)
	Fox Lake Units 1 & 3	(10)	(10)
315.00	ACCESSORY ELECTRIC EQUIPMENT		
	Fox Lake Unit 1	(5)	(5)
	Fox Lake Unit 3	(5)	(5)
	Fox Lake Units 1 & 3	(5)	(5)
316.00	MISCELLANEOUS PLANT EQUIPMENT		
	Fox Lake Unit 1	(5)	(5)
	Fox Lake Unit 3	(5)	(5)
	Fox Lake Units 1 & 3	(5)	(5)

INTERSTATE POWER AND LIGHT COMPANY - MINNESOTA
PROPOSED CHANGE IN NET SALVAGE

	ACCOUNT	PROPOSED NET SALVAGE PERCENT	CURRENT NET SALVAGE PERCENT
	OTHER PRODUCTION PLANT		
342.00	OIL SYSTEM		
	Hills	(5)	(5)
343.00	ENGINES		
	Hills	(5)	(5)
344.00	GENERATORS		
	Hills	0	0
345.00	ACCESSORY ELECTRIC EQUIPMENT		
	Hills	(5)	(5)
	Montgomery	(5)	(5)
346.00	MISCELLANEOUS POWER PLANT EQUIPMENT		
	Hills	0	0
	Montgomery	0	0
	DISTRIBUTION PLANT		
361.00	STRUCTURES AND IMPROVEMENTS	(5)	(5)
362.00	STATION EQUIPMENT	(10)	(10)
364.00	POLES, TOWERS AND FIXTURES	(50)	(50)
365.00	OVERHEAD CONDUCTORS AND DEVICES	(40)	(40)
366.00	UNDERGROUND CONDUIT	(5)	(5)
367.00	UNDERGROUND CONDUCTORS AND DEVICES	(25)	(25)
368.00	LINE TRANSFORMERS	(5)	(5)
369.00	SERVICES	(50)	(50)
370.00	METERS	(5)	(5)
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	(20)	(20)

INTERSTATE POWER AND LIGHT COMPANY - MINNESOTA
PROPOSED CHANGE IN NET SALVAGE

	ACCOUNT	PROPOSED NET SALVAGE PERCENT	CURRENT NET SALVAGE PERCENT
	GENERAL PLANT		
390.00	STRUCTURES AND IMPROVEMENTS	(5)	(5)
390.10	LEASEHOLD IMPROVEMENTS	0	0
391.10	OFFICE FURNITURE AND EQUIPMENT - EXCEPT COMPUTERS	0	0
391.40	OFFICE FURNITURE AND EQUIPMENT - COMPUTERS	0	0
392.00	TRANSPORTATION EQUIPMENT - TRUCKS, TRAILERS AND VANS	10	10
393.00	STORES EQUIPMENT	0	0
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	0	0
395.00	LABORATORY EQUIPMENT	0	0
396.00	POWER OPERATED EQUIPMENT	10	10
397.00	COMMUNICATION EQUIPMENT		
	ELECTRONIC	0	0
	TOWER/BUILDING	0	0
	GAS PLANT		
	DISTRIBUTION PLANT		
375.00	STRUCTURES AND IMPROVEMENTS	0	0
376.00	MAINS	(30)	(30)
378.00	MEASURING AND REGULATING EQUIPMENT - GENERAL	(10)	(10)
379.00	MEASURING AND REGULATING EQUIPMENT - CITY GATE	(10)	(10)
380.10	SERVICES	(80)	(80)
381.00	METERS	(50)	(50)
382.00	METER INSTALLATIONS	(80)	(80)
383.00	HOUSE REGULATORS	(15)	(15)
385.00	IND. MEASURING AND REGULATING STATION EQUIPMENT	0	0
	GENERAL PLANT		
390.00	STRUCTURES AND IMPROVEMENTS	0	0
392.20	TRANSPORTATION EQUIPMENT-TRUCKS	5	5
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	0	0
397.00	COMMUNICATION EQUIPMENT	0	0

INTERSTATE POWER AND LIGHT COMPANY - MINNESOTA
PROPOSED CHANGE IN NET SALVAGE

	ACCOUNT	PROPOSED NET SALVAGE PERCENT	CURRENT NET SALVAGE PERCENT
	COMMON PLANT		
390.00	STRUCTURES AND IMPROVEMENTS	(5)	(5)
391.00	OFFICE FURNITURE AND EQUIPMENT		
	EXCEPT COMPUTERS	0	0
	COMPUTERS	0	0
392.00	TRANSPORTATION EQUIPMENT		
	TRUCKS, TRAILERS AND VANS	20	20
394.00	TOOLS, SHOP AND GARAGE EQUIPMENT	0	0
396.00	POWER OPERATED EQUIPMENT	10	10
397.00	COMMUNICATION EQUIPMENT		
	ELECTRONIC	0	0
	TOWER/BUILDING	0	0
397.40	COMMUNICATION EQUIPMENT - IDEN		
	ELECTRONIC	0	0
	TOWER/BUILDING	0	0

Part 7: A table comparing the resource planning lives and remaining lives for purposes of depreciation

STEAM PRODUCTION PLANT - IOWA	2013 Depreciation Study Date	2012 IRP Retirement Date	RATIONALE FOR DIFFERENCE BETWEEN DEPRECIATION LIFE AND RESOURCE PLANNING PERIOD
Burlington Generating Station	2024	2024	No reconciliation is required as the retirement dates are equal. No formal decision to retire unit, but retirement date assumed for modeling purposes.
Clinton Unit 2 (ML Kapp)	2024	2024	No reconciliation is required as the retirement dates are equal. No formal decision to retire unit, but retirement date assumed for modeling purposes.
Dubuque Unit 3	2014	2014	No reconciliation is required as the retirement dates are equal.
Dubuque Unit 4	2014	2014	No reconciliation is required as the retirement dates are equal.
Lansing Unit 4	2037	2027 (full study period)	The Resource Plan uses a 15 year Planning Period. As the actual depreciation life is beyond the Resource Planning Period, IPL sees no need for further reconciliation.
Louisa Unit 1	2040	2027 (full study period)	The Resource Plan uses a 15 year Planning Period. As the actual depreciation life is beyond the Resource Planning Period, IPL sees no need for further reconciliation.
Neal Unit 3	2035	2027 (full study period)	The Resource Plan uses a 15 year Planning Period. As the actual depreciation life is beyond the Resource Planning Period, IPL sees no need for further reconciliation.
Neal Unit 4	2040	2027 (full study period)	The Resource Plan uses a 15 year Planning Period. As the actual depreciation life is beyond the Resource Planning Period, IPL sees no need for further reconciliation.
Ottumwa	2034	2027 (full study period)	The Resource Plan uses a 15 year Planning Period. As the actual depreciation life is beyond the Resource Planning Period, IPL sees no need for further reconciliation.
Prairie Creek Units 1 & 3	2035	2027 (full study period)	The Resource Plan uses a 15 year Planning Period. As the actual depreciation life is beyond the Resource Planning Period, IPL sees no need for further reconciliation.
Prairie Creek Unit 4	2035	2027 (full study period)	The Resource Plan uses a 15 year Planning Period. As the actual depreciation life is beyond the Resource Planning Period, IPL sees no need for further reconciliation.
Sutherland Unit 1	2014	2016*	No formal decision to retire unit. The depreciation life is shorter to assure that the current investment is recovered in the event that the company does not choose to operate the facility beyond the current depreciable remaining life thus protecting customers from material increases in costs.
Sutherland Unit 3	2024	2016*	No formal decision to retire unit. IPL will review the Iowa Utilities Board (IUB) Marshalltown Generating Station (MGS) RPU/GCU decision to further evaluate the potential retirement date of this unit. The capacity addition of MGS allows for flexibility to potentially retire this unit earlier than the depreciation study date.

OTHER PRODUCTION PLANT - IOWA	2013 Depreciation Study Date	2012 IRP Retirement Date	RATIONALE FOR DIFFERENCE BETWEEN DEPRECIATION LIFE AND RESOURCE PLANNING PERIOD
Burlington Combustion Turbines	2018	2016*	No formal decision to retire unit. IPL will review the IUB MGS RPU/GCU decision to further evaluate the potential retirement date of this unit. The capacity addition of MGS allows for flexibility to potentially retire this unit earlier than the depreciation study date.
Centerville Diesels	2014	2016*	No formal decision to retire unit. The depreciation life is shorter to assure that the current investment is recovered in the event that the company does not choose to operate the facility beyond the current depreciable remaining life thus protecting customers from material increases in costs.
Centerville Combustion Turbines	2014	2016*	No formal decision to retire unit. The depreciation life is shorter to assure that the current investment is recovered in the event that the company does not choose to operate the facility beyond the current depreciable remaining life thus protecting customers from material increases in costs.
Dubuque Diesels	2014	2014	No reconciliation is required as the retirement dates are equal.
Emery Generating Station	2031	2027 (full study period)	The Resource Plan uses a 15 year Planning Period. As the actual depreciation life is beyond the Resource Planning Period, IPL sees no need for further reconciliation.
Grinnell Combustion Turbines	2015	2016*	No formal decision to retire unit. The depreciation life is shorter to assure that the current investment is recovered in the event that the company does not choose to operate the facility beyond the current depreciable remaining life thus protecting customers from material increases in costs.
Lime Creek Combustion Turbines	2031	2027 (full study period)	The Resource Plan uses a 15 year Planning Period. As the actual depreciation life is beyond the Resource Planning Period, IPL sees no need for further reconciliation.
Sutherland Combustion Turbines	2017	2027 (full study period)	No formal decision to retire unit. The depreciation life is shorter to assure that the current investment is recovered in the event that the company does not choose to operate the facility beyond the current depreciable remaining life thus protecting customers from material increases in costs.
Red Cedar Station	2026	2027 (full study period)	No formal decision to retire unit. The depreciation life is shorter to assure that the current investment is recovered in the event that the company does not choose to operate the facility beyond the current depreciable remaining life thus protecting customers from material increases in costs.

WIND GENERATION - IOWA	2013 Depreciation Study Date	2012 IRP Retirement Date	RATIONALE FOR DIFFERENCE BETWEEN DEPRECIATION LIFE AND RESOURCE PLANNING PERIOD
Whispering Willow Wind Farm - East	2034	2027 (full study period)	The Resource Plan uses a 15 year Planning Period. As the actual depreciation life is beyond the Resource Planning Period, IPL sees no need for further reconciliation.

STEAM PRODUCTION PLANT - MINNESOTA	2013 Depreciation Study Date	2012 IRP Retirement Date	RATIONALE FOR DIFFERENCE BETWEEN DEPRECIATION LIFE AND RESOURCE PLANNING PERIOD
Fox Lake Unit 3	2017	2016*	No formal decision to retire unit. IPL will review the IUB MGS RPU/GCU decision to further evaluate the potential retirement date of this unit. The capacity addition of MGS allows for flexibility to potentially retire this unit earlier than the depreciation study date.

OTHER PRODUCTION PLANT - MINNESOTA	2013 Depreciation Study Date	2012 IRP Retirement Date	RATIONALE FOR DIFFERENCE BETWEEN DEPRECIATION LIFE AND RESOURCE PLANNING PERIOD
Hills Diesels	2016	2016*	No reconciliation is required as the retirement dates are equal.

*Note –Estimated retirement dates are contingent upon the other portions of the supply plan, including the proposed MGS, as well as receiving MISO approval that the resources are not needed for system reliability. If IPL builds MGS, IPL would need to reconsider all of its supply options, including whether to make investments to extend the lives of units described above or retire the units earlier.

I. MINNESOTA DEMAND REPONSE POTENTIAL

In its March 2, 2012, *Order Approving Resource Plan with Modifications* issued in Docket No. E001/RP-08-673, the Commission's included Order point 11.d, which requires IPL to "incorporate its demand response study and include the potential for demand response capacity savings in Minnesota within its scenario analyses." IPL includes the requested study below.

A. EGEAS Demand Response Modeling

On September 1, 2011, IPL filed comments in Docket No. E,G999/CI-09-1449, *In The Matter Of An Investigation Of Whether The Commission Should Take Action On Demand Response Bid Directly Into The MISO Markets By Aggregators Of Retail Customers Under FERC Orders 719 And 719-A*. These comments are included as Attachment A. Pages 9-15 of Attachment A specifically cover IPL's Demand Response potential and improvement efforts. The comments noted IPL's expansion of its Interruptible and Time-of-Use (TOU) Pricing, and implementation of a new Direct Load Control (DLC) program in Minnesota. These initiatives were noted to have the potential to increase IPL's Minnesota Demand Response from 1.4 MW to 6.1 MW, for a growth of 4.7 MW[1]. IPL further commented that existing, expanded and new Demand Response programs would altogether represent a four percent demand savings in Minnesota.

IPL is committed to implementing these Minnesota Demand Response programs. IPL has made progress in increasing its Minnesota Interruptible program since the 2011 filing as shown in Table 2 below, and 660 Minnesota customers have signed up for the Direct Load Control program.

Table 1 – IPL Minnesota Demand Response as of 2013

Program	Potential Impact (MW)		
	Current	Proposed	Total
Interruptible	1.75	0.15	1.9
Time-Of-Use Pricing	<0.5	0.5	1.0
Direct Load Control	0	3.2	3.2
Total	2.25	3.85	**6.1**

[1] Note that these values are not necessarily coincident with IPL's system peak for EGEAS purposes.

Because IPL's Minnesota load is a relatively small portion of its total load, changing Minnesota Demand Response levels do not have a significant impact on IPL's expansion plans. In contrast to the additional 3.85 MW of potential Minnesota Demand Response shown in Table 1 above, IPL's EGEAS modeling includes a growth of 41 MW from 302 MW to 343 MW in total Demand Response as shown in Table 2 below.

Table 2 – IPL System Demand and Growth (MW)

Year	Peak	Inter-ruptible	DLC
2014	3,121.3	263.3	38.5
⋮	⋮	⋮	⋮
2029	3,550.9	296.7	46.0
Growth	429.6	33.4	7.5

The expanding Demand Response programs are included in IPL's EGEAS analysis as demand-side resources, which act to modify capacity obligations. As a result, there is no need to test these Minnesota Demand Response programs with scenario analysis.

B. FERC National Assessment Benchmarking

IPL takes this opportunity to describe how it benchmarked its demand response efforts against the June 2009 Federal Energy Regulatory Commission (FERC) Staff Report, "A National Assessment of Demand Response Potential," prepared by The Brattle Group, Freeman, Sullivan & Company, and Global Energy Partners, LLC (National Assessment).[2] IPL read the National Assessment concentrating on the potential for demand response in Minnesota.

Table A-2: Potential Peak Demand Reduction by State (2014) (page 82) of the National Assessment provides a 10-year potential peak demand reductions from a business-as-usual scenario at 12 percent to a full participation scenario at 19 percent. IPL acknowledges that these values are all much higher than its own four percent demand reduction mentioned above. However, IPL notes that the National Assessment (page 18) instructs the reader to interpret the scenario numbers reported "as the amount of demand response that could potentially be achieved under a variety of assumptions about the types of programs pursued, market acceptance of the programs, and the overall cost-effectiveness of the programs." The report "does not advocate what programs/measures should be adopted/implemented by regulators; it only sets forth estimates should certain things occur."

The National Assessment goes on to say, "the estimates of potential in this report should not be interpreted as targets, goals, or requirements for

[2] http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf

individual states or utilities. However, by quantifying potential opportunities that exist in each state, these estimates can serve as a reference for understanding the various pathways for pursuing increased levels of demand response."

Additionally, specifically with regard to the potential peak demand reductions, the National Assessment states, "In this analysis, the use of largely publicly-available, secondary data sources makes it likely that the error range for any particular estimate in each of the scenarios studied is larger, perhaps as high as twenty percent."

IPL took these instructive statements of guidance and caution under consideration when determining its demand response potential. First, IPL evaluated the available demand response programs included in FERC Staff Report, "2010 Assessment of Demand Response & Advanced Metering," issued in February 2011 (2011 FERC Staff Report).[3] Attachment B, *Demand Response Programs,* summarizes IPL's evaluation of all the evaluated demand response programs, as well as its plans to proceed in 2012 and beyond towards improving demand response potential in its Minnesota service territory for each of these programs. The available demand response programs were placed into two primary buckets: (1) those where near-term expansion of the program in IPL's territory would be cost effective; and (2) those where programs were premature or not likely to be cost effective in the near term. In other words, IPL was looking to focus first on the programs most likely to produce tangible benefits. The demand response programs IPL intends to pursue are:

1. Expand interruptible load program;
2. Expand TOU pricing program; and
3. Launch a DLC program for residential central air conditioners and water heaters.

By expanding its existing interruptible load program and adding a new DLC program, IPL intends to work towards enhancing its summer-peaking demand response. IPL is a summer-peaking utility and both of these are summer-peaking demand response programs.

The interruptible load program is an incentive-based demand response program IPL offers to commercial, industrial and institutional customers. Currently, the program is capable of providing approximately 1.75 MW of load reduction from its 12 participants.

The TOU pricing program is time-based, and is available to residential, commercial, industrial and institutional customers. This program is currently estimated to provide less than 500 kW of load reduction from its 25 participants.

IPL evaluated demand response potential and opportunities for improvement of these two programs and one new program, DLC.

For each of the three programs, IPL's analysis was based on two criteria; primary data, IPL's demand response experience and customer information in both its Minnesota and Iowa service territories; as well as secondary research.

[3] http://www.ferc.gov/legal/staff-reports/2010-dr-report.pdf

Interruptible Load Program

Based on the tariff requirement that a customer cannot reduce his or her firm load below the tariff minimum 50 kW billing demand, IPL calculated the actual average four-month (May through August) usage for 2010 of each commercial, industrial and institutional customer and identified 130 customers as potentially eligible for the program. Applying the same percentage of eligible customers who actually participate in Iowa's interruptible program to Minnesota's eligible customers, IPL approximates 51 participants could participate in Minnesota's interruptible program. However, after reviewing the types of businesses eligible to participate in Minnesota, IPL more practically estimates the potential number of program participants at 26, or twice the current number of customers participating.

Basing the load potential on the calculated average usage data for the summer months, IPL selected 26 customers from the median and assumed they would all reduce their load from their 2010 average summer demand to 50 kW. Totaling these customers' load reductions, IPL estimates the total interruptible load program potential to be 1.9 MW, and as noted with participation levels, the load reduction is almost a 100 percent increase in the program's potential.

Time-of-Use Pricing Program

Although IPL offers a TOU tariff to every customer class, only 26 customers currently participate. Assuming a four percent market participation rate, IPL approximates 1,680 of the 42,000 electric customers may participate in IPL's enhanced TOU pricing program. This anticipated increase in program participation is 167 percent over the current program participation level.

Direct Load Control

IPL based its proposed DLC demand and energy savings impacts on its DLC program experience in its Iowa service territory as well as secondary research. Although new to IPL's customers in Minnesota, IPL has been offering a DLC program in Iowa since 1991 as part of Iowa's first energy efficiency plan. IPL's Central Air Conditioning and Electric Water Heater cycling programs are described below.

DLC - Air Conditioning Controls (ACC) Impacts

Specific to impacts for ACC, IPL first determined the number of IPL residential customers with central air conditioners (CAC) in Minnesota. To attain this number, IPL chose a more recent data source than the National Assessment. The 2011 Residential Energy Use Study (Attachment C) completed by E-Source included an appliance saturation analysis for cooling equipment in the Midwest. Although the value represented a larger region and was 16 percent higher than the National Assessment value of 51 percent (page 221), based on its experience in Iowa, IPL believed the Midwest value was representative of its service territory since it primarily covers southern Minnesota.

IPL applied the higher Midwest CAC saturation rate of 67 percent to the 33,528 IPL electric retail residential customers in Minnesota, resulting in an estimated 22,464 IPL residential electric customers with CAC in Minnesota.

Next, IPL applied Iowa's program market penetration rate of 17 percent to the 22,464 CAC resulting in an estimated 3,764 customers/ACC. IPL launched the DLC project last year with projected annual participation levels increasing and reaching 17 percent year-end 2015 (see Table 4: Minnesota Direct Load Control Project – 2015).

IPL used a demand savings of 0.8 kilowatts (kW) per ACC based on a KEMA Process and Impact Evaluation of Residential Direct Load Control Program report dated March 27, 2006, and 1.33 kWh per cycling event to calculate the energy savings. The energy savings is based on one cycling event each month. Please see Attachment D for calculations and annual impacts for the 2013 to 2015 period.

Total ACC demand savings in August 2015 will equal 2,828 kW after a six percent line loss is applied. Annual energy savings for 2015 will be 17,560 kWh after a six percent line loss is applied.

Table 3 – Minnesota Direct Load Control Project - 2015

Appliance Type	% of DLC Project Participation	Estimated Project Participants	Impact Savings per Participant[4] (kW)	Estimated August Impacts by Equipment Type (kW) - Generator	Estimated Impacts by Measure Type (kWh)
Central Air Conditioner	17%	3,764	0.8	2,828[1]	17,560
Electric Water Heaters	7%	702	0.2	131[1]	0
Total Estimated Impacts for Direct Load Control Project				**2,960**	**17,560**

[1] Used August peak

<u>DLC – Electric Water Heater Cycling (WHC)</u>

Specific to impacts for WHC, IPL first determined the number of IPL residential customers with electric water heaters (EWH) in Minnesota. To attain this number, IPL again cited the 2011 Residential Energy Use Study (Attachment E) completed by E-Source. This study included an appliance saturation analysis for water heating equipment in the Midwest. The National Assessment did not provide an EWH saturation value. IPL applied the Midwest EWH market penetration rate of 34 percent to the 33,528 IPL electric retail residential customers, resulting in an estimated 11,400 IPL residential electric customers with EWH in Minnesota. IPL then lowered this number to a more conservative 10,000 customers/EWH measures, acknowledging that specific to IPL, its service territory is predominantly rural with propane used as the heating fuel source.

Next, IPL applied Iowa's program market penetration rate of seven percent to the 10,000 EWH resulting in an estimated 700 customers/EWH measures participating. As mentioned above, with the launch of the project in 2013, IPL projects participation levels to increase annually and reach seven percent by year-end 2015 (see Table 4: Minnesota Direct Load Control Project – 2015).

IPL used a demand savings of 0.2 kW per WHC based on the same KEMA report referenced for central air conditioners. Demand savings in August 2015 will equal 131 kW after a six percent line loss is applied. There is no energy savings calculated for water heaters.

Based on these estimated customer participation levels and taking a conservative approach of assuming one appliance per participant for the respective measure type, IPL estimates a total project peak load reduction of 3 MW in August 2015.

To summarize, after completing the described demand response evaluation, IPL deemed the National Assessment demand reduction potential not applicable to its service territory. IPL's demand response potential values were based on primary data collected from IPL's customer information system database and its demand response experience in Iowa and Minnesota, as well as more current and applicable secondary data. Conversely, the National Assessment model utilized limited inputs to represent IPL's Minnesota service territory. The model relied heavily on applying estimates based on secondary 2008 and earlier data from across the United States; it simply assumes that the customer behavior in those other areas is applicable to IPL's Minnesota service territory rather than using primary customer research from this service territory.

ALLIANT ENERGY
Interstate Power and Light

Interstate Power and Light Co.
An Alliant Energy Company

Alliant Tower
200 First Street SE
P.O. Box 351
Cedar Rapids, IA 52406-0351

Office: 1.800.822.4348
www.alliantenergy.com

Alliant Energy Corporate Services
Legal Department
319-786-7765 – Phone
319-786-4533 – Fax

Paula N. Johnson
Senior Attorney – Regulatory

September 1, 2011

Dr. Burl Haar, Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

RE: Interstate Power and Light Company
Docket No. E,G999/CI-09-1449
Comments

Dear Dr. Haar:

Enclosed for e-Filing with the Minnesota Public Utilities Commission, please find Interstate Power and Light Company's Comments in the above-referenced docket.

Copies of this filing have been served on the Minnesota Department of Commerce, Division of Energy Resources, the Minnesota Office of Attorney General - Residential and Small Business Utilities Division and the attached service list.

Respectfully submitted,

/s/ Paula N. Johnson
Paula N. Johnson
Senior Attorney – Regulatory

PNJ/tao
Enclosures

cc: Service List

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	**Chair**
David Boyd	**Commissioner**
J. Dennis O'Brien	**Commissioner**
Phyllis Reha	**Commissioner**
Betsy Wergin	**Commissioner**

IN THE MATTER OF AN INVESTIGATION OF WHETHER THE COMMISSION SHOULD TAKE ACTION ON DEMAND RESPONSE BID DIRECTLY INTO THE MISO MARKETS BY AGGREGATORS OF RETAIL CUSTOMERS UNDER FERC ORDERS 719 AND 719-A	**DOCKET NO. E,G999/CI-09-1449**

AFFIDAVIT OF SERVICE

STATE OF IOWA)
) ss.
COUNTY OF LINN)

Tonya A. O'Rourke, being first duly sworn on oath, deposes and states:

That on the 1st day of September, 2011, copies of the foregoing Affidavit of Service, together with Interstate Power and Light Company's Comments, were served upon the parties on the attached service list, by e-filing, overnight delivery, electronic mail, and/or first-class mail, proper postage prepaid from Cedar Rapids, Iowa.

<u>/s/ Tonya A. O'Rourke</u>
Tonya A. O'Rourke

Subscribed and Sworn to Before Me
This 1st day of September, 2011.

/s/ Kathleen J. Faine
Kathleen J. Faine
Notary Public
My Commission Expires on February 20, 2012

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	OFF_SL_9-1449_Official
Keith L.	Beall	kbeall@midwestiso.org	Midwest ISO Legal Dept.	P.O. Box 4202 Carmel, IN 46082	Paper Service	No	OFF_SL_9-1449_Official
Peter	Beithon	pbeithon@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_9-1449_Official
Michael	Bradley	bradleym@moss-barnett.com	Moss & Barnett	4800 Wells Fargo Ctr 90 S 7th St Minneapolis, MN 55402-4129	Electronic Service	No	OFF_SL_9-1449_Official
Brian	Draxten		Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380498	Paper Service	No	OFF_SL_9-1449_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_9-1449_Official
Ronald M.	Giteck	ronald.giteck@ag.state.mn.us	Office of the Attorney General-RUD	Residential Utilities Division 445 Minnesota Street, 900 BRM Tower St. Paul, MN 55101	Paper Service	No	OFF_SL_9-1449_Official
Burl	Haar	burl.haar@state.mn.us	Public Utilities Commission	121 7th Place East Suite 350 St. Paul, MN 55101-2147	Electronic Service	No	OFF_SL_9-1449_Official
Lori	Hoyum	lhoyum@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_9-1449_Official
Paula N.	Johnson		Interstate Power and Light Company	200 First Street SE PO Box 351 Cedar Rapids, IA 524060351	Paper Service	No	OFF_SL_9-1449_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Jeffrey L.	Landsman	jlandsman@wheelerlaw.com	Wheeler, Van Sickle & Anderson, S.C.	Suite 801 25 West Main Street Madison, WI 537033398	Paper Service	No	OFF_SL_9-1449_Official
John	Lindell	agorud.ecf@state.mn.us	Office of the Attorney General-RUD	900 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	OFF_SL_9-1449_Official
John	McWilliams	jmm@dairynet.com	Dairyland Power Cooperative	3200 East Ave SPO Box 817 La Crosse, WI 54601-7227	Electronic Service	No	OFF_SL_9-1449_Official
Andrew	Moratzka	apm@mcmlaw.com	Mackall, Crounse and Moore	1400 AT&T Tower 901 Marquette Ave Minneapolis, MN 55402	Paper Service	No	OFF_SL_9-1449_Official
SaGonna	Thompson	Regulatory.Records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_9-1449_Official
Mona	Tierney-Lloyd	mtierney-lloyd@enernoc.com	EnerNoc Inc	P. O. Box 378 Cayucos, CA 93430	Paper Service	No	OFF_SL_9-1449_Official

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Ellen Anderson	**Chair**
David C. Boyd	**Commissioner**
J. Dennis O'Brien	**Commissioner**
Phyllis A. Reha	**Commissioner**
Betsy Wergin	**Commissioner**

IN THE MATTER OF AN INVESTIGATION OF WHETHER THE COMMISSION SHOULD TAKE ACTION ON DEMAND RESPONSE BID DIRECTLY INTO THE MISO MARKETS BY AGGREGATORS OF RETAIL CUSTOMERS UNDER FERC ORDERS 719 AND 719-A	**DOCKET NO. E999/CI-09-1449**

INTERSTATE POWER AND LIGHT COMPANY'S COMMENTS

COMES NOW, Interstate Power and Light Company (IPL), and hereby submits its Comments to the Minnesota Public Utilities Commission's (Commission) *Order Prohibiting Bidding of Demand Response Into Organized Markets By Aggregators Of Retail Customers and Requiring Further Filings By Utilities* issued on May 18, 2010 (May 18, 2010 Order), and *Order Requiring Further Filings By Utilities* issued on February 8, 2011 (February 8, 2011 Order), in the above-referenced docket.

I. INTRODUCTION

On January 13, 2010, the Commission issued its *Notice of Public Comment Period* requesting comments "on the potential effects of ARCs [Aggregators of Retail Customers] on utility rates, reliability, demand-side management [DSM], conservation programs; on participating and non-participating utilities and customers; and other relevant issues...." (Notice, p. 1.) This inquiry was spurred by Order No. 719 issued on October 17, 2008, by the Federal Energy Regulatory Commission (FERC), directing Regional Transmission Organizations (RTOs), including the Midwest Independent Transmission System Operator, Inc. (MISO), to amend their market rules to allow ARCs to offer demand response (DR) resources from retail customers of larger utilities directly into the RTO wholesale energy and ancillary services markets, barring prohibition of such offers by the laws of the applicable regulatory authority.

In the instant case, the Commission is the applicable relevant electric regulatory authority with jurisdiction over the retail electric utilities in the state of Minnesota. IPL provides comments on the issues below, as requested by the Commission.

In the May 18, 2010, Order at Ordering Point No. 3, the Commission required Xcel Energy, Minnesota Power Company, IPL and Otter Tail Power Company to make filings describing their DR programs. The Order further required:

> 3. On or before September 1, 2011, Xcel Energy, Minnesota Power, Interstate Power and Light and Otter Tail Power shall file two reports:
>
> a. a report on ARC operations in the wholesale markets operated by MISO and in the wholesale markets operated by other independent system operators and regional transmission organizations, focusing specifically on the impact of ARC operations on process, reliability, nonparticipating customers, utility operations, and utility-operated demand response programs; and
>
> b. a report on the tariff and program changes that each utility believes would be necessary to accommodate ARC operations in Minnesota.

On June 28, 2010, Xcel Energy, Minnesota Power, IPL and Otter Tail Power filed submissions describing their DR programs.

On August 25, 2010, the Minnesota Office of Energy Security (OES), now known as the Department of Commerce, Division of Energy Resources (Department), EnerNOC, Inc. (EnerNOC) and the Large Industrial Group filed comments.

By September 25, 2010, each utility filed comments in response to the Department's comments.

The Commission's February 8, 2011, Order required the following:

1. Xcel Energy, Minnesota Power, Interstate Power and Light and Otter Tail Power shall file comments by September 1, 2011, on the ability to expand demand response options through contracts with third parties in order to achieve demand response potential.
2. Interstate Power and Light shall make an additional filing by September 1, 2011, on demand response potential in its service territory in Minnesota and specific efforts it will take to improve its demand response.

With that, IPL provides its comments to the Ordering Point No. 3 in the Commission's May 18, 2010, as well as Ordering Point No. 1 and No. 2 from the Commission's February 8, 2011, Order.

II. IPL'S COMMENTS

<u>IPL Response to May 18, 2010 Commission Ordering Point No. 3</u>

A. The Commission's May 18, 2010, Order, at Ordering Point No. 3, requires IPL to report on ARC operations in the wholesale markets operated by MISO and in the wholesale markets operated by other independent system operators and regional transmission organizations, focusing specifically on the impact of ARC operations on process, reliability, nonparticipating customers, utility operations, and utility-operated DR programs.

Xcel Energy, Minnesota Power Company, Otter Tail Power Company and IPL commissioned the Mendota Group to prepare a report on ARC operations in wholesale markets. The report is provided in Attachment A.

B. Additionally, the May 18, 2010, Order, at Ordering Point No. 3, requires IPL to report on the tariff and program changes that it believes would be necessary to accommodate ARC operations in Minnesota.

The attached report on ARC operations around the country demonstrates a clear split. ARCs are active in the wholesale markets that include states with retail access. ARCs are not active in wholesale markets where traditional vertical integration of utilities prevails. The reason for this split is straightforward. Under traditional utility regulation and rate design, a utility's rate design is based on average cost within a class of service and within time-of-use periods. Regulators in those states recognize that allowing ARCs to sell the DR of the utility customers to the wholesale market is essentially providing a free option to the ARC and its utility customer-partner, wherein the ARC can arbitrage the difference between hourly marginal energy prices and the average cost prices of retail service. This option, if exercised, harms non-participating retail customers through the operation of fuel adjustment clauses. In contrast, in retail access states, the cost of power supply is strictly between the individual retail customer and its third-party power supplier.

Overall, it appears those regulators have recognized that, in retail access states, non-participating customers would not be harmed through ARC operations.

Despite these concerns about ARC participation in vertically integrated states such as Minnesota, IPL views the development of the MISO energy market as providing new opportunities to improve and enhance the DR options that can be provided to customers.

Under IPL's current rate design, however, the potential obligation of this additional tariff provision/credit could conflict with equitable treatment of all customers. IPL recognizes there may be some benefits derived from incenting additional demand control tools, and recommends that each Minnesota utility be allowed to file provisions in its future retail rate cases to address each utility's unique situation, recognizing that tariff reform is needed to achieve equitable treatment.

Specifically, IPL believes that providing Minnesota retail customers the opportunity to resell energy at marginal rates, while at the same time requiring IPL to provide the energy to these customers at average rates, is inequitable to IPL's non-participating customers. With its tariff rates based upon embedded average costs, IPL currently does not have a tariff in which a retail customer is billed the prevailing market based cost of power that will fluctuate from hour to hour and day to day.

IPL aggregates the load of all customers and has an obligation to serve all customers at an average system cost rate. IPL's current tariffs do not allow it to charge customers the real-time price of the MISO markets when prices are high, while continuing to charge customers based on the class-average cost at other times.

Under the proposed rule, ARC customers would have the choice of receiving service from IPL anytime at a rate based upon customer class-average prices that reflects IPL's cost to provide service based upon the aggregation of load of diverse groups of customers. At the same time, the ARC customers would retain the right to opt out of the cost-based rates when it is beneficial for them to do so, and extract a marginal price payment from MISO's markets. In IPL's current class cost of service study, there is not currently any mechanism that addresses the potential of customers opting out of cost-based rates, and thus the shifting of costs to non-participating retail customers.

Additionally, IPL's Minnesota tariff also precludes retail customers from reselling IPL's power.[1] Currently, customers are only allowed to resell the load if it is taken at a predetermined resale tariff. With ARCs, the customer and the ARC create a futures market with the customer reselling his or her load to the ARC to settle the option. When ARC customers determine it is in their best interest to receive service from the system, this is the point in which IPL's non-participating customers would bear part of the cost and the risk of providing service, but they would not share in the value created when the ARC customers opt out of the aggregation pool and sell their DR into the markets. ARC customers should not reap the benefit of load reduction when there are no system savings, while at the same time increasing system costs. IPL's tariffs currently do not reflect this shifting of costs to the non-participating retail customers.

[1] IPL recognizes that FERC, in Order 719, concluded that ARCs are providing a service instead of selling a product. Yet the filed (yet to be approved by FERC) MISO compliance tariffs treat the offer of demand reduction as any other energy product is treated. In IPL's view, ARC-offered demand reduction is a re-sale of retail power, which is prohibited by IPL's tariff.

Participation of ARCs could also result in increased administrative, marketing and regulatory costs for IPL. While IPL and the Commission strive for low-cost reliable electric service and associated energy conservation programs, the allowance of ARCs could result in multiple competing costs. To the extent that such costs are not directly chargeable to customers participating with ARCs, this would only lead to higher rates for IPL's overall Minnesota customer base.

As noted above, IPL does not currently have a tariff offering based on the prevailing market-based cost of power; if such a tariff were proffered by IPL and approved by the Commission, then it may be acceptable to allow ARCs to operate with customers taking service on such a tariff.

Finally, IPL currently has pending before the Commission a revised interruptible tariff for its nonresidential customers to implement enhanced DR (part of the pending electric rate case in Docket No. E001/GR-10-276). The proposed interruptible tariff provides interruptible customers with rate credits in exchange for allowing IPL to ask customers to interrupt services under certain circumstances (e.g., when needed to keep the lights on or if total system load or prices are very high). Under the current MISO tariff and market regime, IPL may offer this interruptible load into the day-ahead market. These arrangements serve to reduce (for reliability, power supply planning and resource adequacy purposes) the firm load IPL would otherwise be required to serve. Consequently, IPL avoids planning for and carrying generation capacity to serve these loads. Because the cost of the customers' interruptible rate credits is reflected in IPL's average rate, the resulting cost savings (of not carrying generation for this load) are allocated among IPL's customers in accordance with its current retail rate design and class cost of service study.

ARC operation may put IPL's interruptible tariff at risk because it would be inequitable to allow customers to retain interruptible rate credits through participation in the interruptible program if these customers are also offering this same load reduction in demand into MISO via an ARC. These customers cannot do both, since they would be "free-riding" on the firm system if they were granted interruptible rate credits.

IPL Response to February 8, 2011 Order Points No. 1 and No. 2

A. The Commission's February 8, 2011, Order, at Ordering Point No. 1, directed IPL to file comments by September 1, 2011, on the ability to expand DR options through contracts with third parties in order to achieve DR potential.

EnerNOC representatives, an energy services company advocating ARCs in this docket, met with IPL staff on September 27, 2010, at IPL's offices in Cedar Rapids, Iowa. IPL's objectives in that meeting were to gain an understanding of the products and services offered by EnerNOC and to identify if there were any opportunities for an ongoing business relationship. EnerNOC initiated the meeting by providing a thorough description of its business. IPL then provided background on its existing DR programs and customer demographics. After sharing this information with one another and having further discussions, including answering each other's questions, it was mutually agreed by both parties that at that time, EnerNOC did not have any opportunities to expand DR options for IPL. IPL and EnerNOC have continued to stay in communication since this meeting at industry trade shows (e.g. Electric Power Research Institute, Association of Energy Services Professionals, Rural Electricity Resource Council) and via telephone. IPL will continue to do so as EnerNOC's DR offerings evolve.

IPL is not aware at this time of any other third-party vendors who offer DR options.

B. The Commission's February 8, 2011, Order, at Ordering Point No. 2, required IPL to make an additional filing by September 1, 2011, on DR potential in its service territory in Minnesota and the specific efforts it will take to improve its DR utilization.

In responding to the Commission's February 8, 2011, Order at Ordering Point No. 2, IPL first evaluated the available DR programs included in the most recent DR report[2] published by the FERC. Attachment B, *Demand Response Programs,* summarizes IPL's evaluation of all the evaluated DR programs, as well as its plans to proceed in 2012 towards improving DR potential in its Minnesota service territory for each of these programs. The available DR programs were placed into two primary buckets: (1) those where near-term expansion of the program in IPL's territory would be cost effective and (2) those where programs were premature or not likely to be cost effective in the near term. In other words, IPL was looking to focus first on the programs most likely to produce tangible benefits.

The DR programs IPL intends to pursue in the near term are (see Table 1: IPL 2012 Demand Response Programs):

---

[2] *Assessment of Demand Response & Advanced Metering*, Staff Report, FERC, February 2011.

1. Continue plans (initiated in IPL's current rate case) to enhance its **interruptible load program**, including marketing, once the program is in place;
2. Continue plans (initiated in IPL's current rate case) to enhance its **time-of-use (TOU) pricing program**, including marketing, once the program is in place; and
3. Create and implement a **direct load control (DLC) program** for residential central air conditioners and water heaters.

Table 1: IPL 2012 Demand Response Programs

Program	Potential Impact (MW)		
	Current	Proposed	Total
Interruptible	0.9	1.0	1.9
Time-of-Use Pricing	<0.5	0.5	1.0
Direct Load Control	0	3.2	3.2
Total IPL 2012 Demand Response Potential Impact (MW)			**6.1**

By expanding its existing interruptible load program and adding a new DLC program IPL intends to work towards enhancing its summer-peaking DR. IPL is a summer-peaking utility and both of these are summer-peaking DR programs.

The interruptible load program is an incentive-based DR program IPL offers to commercial, industrial and institutional customers. Currently, the program is capable of providing approximately one megawatt (MW) of load reduction from its 13 participants.

The TOU pricing program is time-based, and is available to residential, commercial, industrial and institutional customers. This program is currently estimated to provide less than 500 kilowatts (kW) of load reduction from its 25 participants.

IPL has evaluated DR potential and opportunities for improvement of these two programs and one new program, DLC.

For each of the three programs, IPL's analysis was based on two criteria; DR experience in both its Minnesota and Iowa service territories as well as secondary research.

Interruptible Load Program

Based on the tariff requirement that a customer cannot reduce his or her firm load below the tariff minimum 50 kW billing demand, IPL calculated the actual average four-month (May through August) usage for 2010 of each commercial, industrial and institutional customer and identified 130 customers as potentially eligible for the program. Applying the same percentage of eligible customers who actually participate in Iowa's interruptible program to Minnesota's eligible customers, IPL approximates 51 participants could participate in Minnesota's interruptible program. However, after reviewing the types of businesses eligible to participate in Minnesota, IPL more practically estimates the potential number of program participants at 26, or twice the current number of customers participating.

Basing the load potential on the calculated average usage data for the summer months, IPL selected 26 customers from the median and assumed they would all reduce their load from their 2010 average summer demand to 50 kW. Totaling these customers' load reductions, IPL estimates the total interruptible load program potential to be 1.9 MW, and as noted with participation levels, the load reduction is almost a 100 percent increase in the program's potential.

To improve this program and its potential, in its current electric retail rate case (Docket No. E001/GR-10-276), and as also noted on page 7 of these comments, IPL filed a revised interruptible tariff for commercial, industrial and institutional customers. The proposed buy-through option has been added to encourage participation. After Commission approval, IPL intends to market this program to all eligible customers through direct contact from key account management, customer support services and/or mail, and alliantenergy.com.

Time-of-Use Pricing Program

Although IPL offers a TOU tariff to every customer class, only 25 customers currently participate. To enhance this program and its potential, in its current electric retail rate case (Docket No. E001/GR-10-276), IPL filed revised TOU tariffs for residential, commercial, industrial and institutional customers. The proposed energy charges and peak periods have been adjusted to encourage participation.

After Commission approval, IPL intends to market this program to all customers through direct contact from key account management, customer support services and/or mail, and alliantenergy.com, reaching approximately 42,000 electric customers.

Assuming a four percent market participation rate, IPL approximates 1,680 of the 42,000 electric customers may participate in IPL's enhanced TOU pricing program. This anticipated increase in program participation is 167 percent over the current program participation level.

Direct Load Control

Although new to IPL's customers in Minnesota, IPL has been offering a DLC program in Iowa since 1991 as part of Iowa's first energy efficiency plan. With this program, residential customers allow IPL to control their central air conditioners and/or water heaters. This program helps IPL balance load by remotely controlling the appliances during peak periods. Today, 50,982 of an estimated 304,288[3] Iowa IPL residential electric customers with central air conditioning volunteer to have their air conditioners cycled. And 8,253 of an estimated 111,734[3] Iowa IPL residential electric customers with electric water heaters volunteer to have their water heaters cycled. Respectively, these participation levels represent 17 percent and seven percent program participation rates.

Specific to central air conditioners, applying Iowa's program market penetration rate of 17 percent to the estimated 22,464[3] IPL residential electric customers with central air conditioning in Minnesota results in 3,764 customers participating. Specific to water heaters, applying Iowa's program market penetration rate of seven percent to the estimated 9,518[3] IPL residential electric customers with electric water heaters in Minnesota results in an estimated 703 customers participating. Based on these estimated customer participation levels in Minnesota, IPL estimates a total program peak load reduction of 3.2 MW annually (see Table 2: Minnesota Direct Load Control Program).

[3] Source: *E-Source 2011 Residential Energy Use Study.*

Table 2: Minnesota Direct Load Control Program

Equipment Type	% of DLC Program Participation	Estimated Program Participants	Impact Savings per Participant[4]	Estimated Impacts by Equipment Type (KW)
Central Air Conditioner	17%	3,764	0.8	3,011
Water Heater	7%	703	0.2	141
Total Estimated Impacts for Direct Load Control Program				**3,152**

The estimated demand savings and reasonable program startup costs are encouraging and IPL intends to file a DLC program in its 2013-2015 Conservation Improvement Program pending benefit/cost analysis.

In summary, IPL's current DR programs total 1.4 MW of potential peak load reduction. IPL is proposing enhancements to two existing DR programs and the addition of one new DR program that could potentially total an additional 4.7 MW of potential peak load reduction. Altogether, IPL plans to offer, in 2012 and beyond, DR programs that could potentially reduce IPL's system peak load by approximately 6.1 MW. Based on IPL's 2010 summer system peak of 151.8 MW, this represents a four percent demand savings of IPL's system peak.

IPL appreciates this opportunity to provide input to the Commission on this important topic.

[4] Source: *Residential Direct Load Control*, Program Evaluation Report, KEMA, 2006.

WHEREFORE, IPL respectfully requests the Commission give IPL's Comments due consideration.

DATED this 1st day of September 2011.

Respectfully submitted,

INTERSTATE POWER AND LIGHT COMPANY

By: */s/ Paula N. Johnson*

Paula N. Johnson
Senior Attorney - Regulatory
Alliant Energy Corporate Services, Inc.
200 First Street S.E.
P.O. Box 351
Cedar Rapids, IA 52406-0351
(319) 786-4742
paulajohnson@alliantenergy.com

Aggregators of Retail Customers: Impacts on RTO Markets

Xcel Energy, Minnesota Power, Otter Tail Power, Interstate Power & Light

The Mendota Group, LLC
Olivine, Inc.

August 30, 2011

Table of Contents

Executive Summary

The following report responds to the Minnesota Public Utilities Commission's request that Minnesota utilities provide a report on the effects of aggregators of retail customers (ARCs) on prices, reliability, nonparticipating customers, utility operations, and utility-administered demand response programs in the wholesale markets operated by the Midwest Independent Transmission System Operator (MISO) and other independent system operators. The report concludes that such a request cannot be readily answered with publicly available data and that, if such data were available, definitive conclusions would still be difficult to draw.

Therefore, the following report instead seeks to review existing studies, supplemented by discussions and interviews with RTO, utility and regulatory representatives, other experts, and ARCs in an effort to thoroughly examine the issues the PUC raises. This review also did not lead to definitive conclusions but does help to define the role ARCs play in Northeastern RTOs and the effects demand response generally has on prices, reliability and nonparticipants. The study contends that demand response does indeed reduce prices and increase reliability. Although the extent to which ARCs are responsible for these benefits is not possible to determine with available information, it is reasonable to conclude that they are partially responsible to the extent that they increase participation in demand response activities. Current experience indicates that ARCs' greatest contributions are to increased reliability given their more active participation in capacity markets.

This study determined that MISO has no existing ARC participation and so current comparisons between MISO and other RTOs are not possible. However, it can be inferred that ARC participation in MISO markets would alter the current demand response program structure and require meaningful changes to existing Midwest utility demand response programs, which are primarily interruptible programs serving residential, commercial and industrial customers.

Minnesota's very robust levels of utility demand response participation make the state an attractive target for ARCs because there exists a base of customers who are very familiar with demand response. This high level of demand response participation means that integration of ARCs into Minnesota's markets must be carefully considered because additional demand response benefits are uncertain but implementation costs are virtually guaranteed. In requesting that utilities submit reports on tariff changes required to accommodate ARC operations, the PUC is investigating one way to facilitate ARC participation. Should the PUC proceed with any changes in current policy related to ARCs, the findings of this study support establishing mechanisms to test the effects the PUC is interested in understanding in order to better understand the benefits that ARCs may bring to Minnesota customers and the costs associated with enabling their participation.

Section 1: Study Objectives

Respond to regulatory issues

Minnesota's investor-owned electric utilities (Xcel Energy, Minnesota Power, Otter Tail Power, and Interstate Power and Light) commissioned this report to answer questions posed by the Minnesota Public Utilities Commission ("Commission" or "PUC") in its May 18, 2010 Decision in Docket No. E-999/CI-09-1449.[1] Order Point 3 of that Decision states,

> 3. On or before September 1, 2011, Xcel Energy, Minnesota Power, Interstate Light and Power, and Otter Tail Power shall file two reports:
>   a. a report on ARC operations in the wholesale markets operated by MISO and in the wholesale markets operated by other independent system operators and regional transmission organizations, focusing specifically on the impact of ARC operations on prices, reliability, nonparticipating customers, utility operations, and utility-operated demand response programs; and
>   b. a report on the tariff and program changes that each utility believes would be necessary to accommodate ARC operations in Minnesota.[2]

This report focuses on 3.a. Utilities will provide responses to 3.b. in separate documents.

Determine impact of ARCs by addressing additional questions

Although the Commission asks straightforward questions, the answers to these questions are complicated. The complexities stem from the nature and diversity of the RTOs in which ARCs operate and the difficulty of distinguishing between ARCs and other demand response participants in wholesale markets and the interaction of retail demand response with the wholesale markets. As with many policy questions, these complexities make it difficult to provide definitive answers to the Commission's questions without direct access to detailed and likely confidential ISO/RTO data. Thus, in an attempt to provide a meaningful response to the Commission's direction, the authors have re-phrased and expanded upon the PUC's questions.

These questions follow:

- What impacts do ARC operations have on prices?
    - Does demand response generally have an impact on prices?
    - Can one draw distinctions between ARC and non-ARC participation in wholesale markets in order to explain potential differential impacts on prices?
- What impacts do ARC operations have on reliability?

[1] "In the Matter of an Investigation of Whether the Commission Should Take Action on Demand Response Bid Directly into MISO Markets by Aggregators of Retail Customers Under FERC Orders 719 and 719-A," Minnesota Public Utilities Commission (Docket No. E-999/CI-09-1449), May 10, 2010.

[2] "In the Matter of an Investigation of Whether the Commission Should Take Action on Demand Response Bid Directly into MISO Markets by Aggregators of Retail Customers Under FERC Orders 719 and 719-A," p. 7.

    - Does demand response generally have an impact on reliability?
    - Can one draw distinctions between ARC and non-ARC participation in wholesale markets in order to explain potential differential impacts on reliability?
- What impacts do ARC operations have on nonparticipating customers?
    - Would nonparticipating customers be impacted differently from ARC vs. non-ARC demand response programs?
    - Is it possible to determine whether the benefits of ARCs exceed their costs?
- What impacts do ARC operations have on utility operations?
    - What is the definition of utility operations?
    - Is this a relevant question if "utilities" in the RTOs in which ARCs operate are basically distribution companies [because the retail markets have been deregulated]?
    - Does a deregulated retail market facilitate ARC participation and reduce the potential impacts on utility operations?
- What impacts do ARC operations have on utility-administered demand response programs?
    - Do utilities in RTOs in which ARCs are active have significant utility-administered demand response programs?
    - Can utility and ARC-administered demand response programs complement one another?
    - Do utility and ARC-administered demand response programs compete?

Refining and re-phrasing the questions helps clarify the issues the PUC's questions raise. The following sections address these issues.

The report is organized as follows. The first section provides an overview of the study's objectives. The second section explains the approach the authors have taken to address the questions. The third section explains the study's finds and the fourth section provides recommended next steps. The final section concludes the report.

Section 2: Study Approach

Summary of secondary research, not primary

As a first step, this report must determine how to assess the impacts of ARC operations on prices, reliability, nonparticipating customers, utility operations, and utility-operated demand response programs. Ideally, the study would address the first three elements (prices, reliability and nonparticipating customers) using primary research to produce specific quantitative estimates. For example, "ARC operations in the PJM Interconnection have resulted in a reduction/an increase in prices of 5 percent over the 2009-2010 period."

Unfortunately, such a quantitative study would require significant amounts of time, resources, and access to detailed RTO/ISO data. Even with such access, specific quantitative results are unlikely since RTOs do not segregate ARCs from non-ARCs for reporting purposes. In addition, because of the nature of prices and reliability, demand response impacts, and the integrated nature of ARC participation in wholesale markets, such a study would likely not yield definitive results.

Given these constraints, the authors conducted a search for existing (primary data) reports but found little that would facilitate direct answers to the PUC's questions. This search included reviews of existing reports about the effects of demand response generally on prices, reliability and other relevant topics, inquiries to organizations familiar with these topics, discussions with representatives of the targeted Independent System Operators (ISOs) – the Midwest ISO (MISO), the PJM Interconnection (PJM), ISO New England (ISO-NE), and the New York ISO (NYISO), and conversations with ARCs and utilities. Although this search elicited some useful primary data about demand response, this data did not support complete answers to the PUC's questions.

This review led the authors to conclude that the best approach to answering the questions was to use primary data (conversations with knowledgeable sources) and some secondary data to address the effects of ARCs on utility operations and utility-administered demand response programs and to use secondary data (RTO reports, consultant and academic reports, regulatory decisions) to attempt to address the effects ARCs have on prices, reliability and non-participants.

Despite the aforementioned limitations, there is ample information about the impacts demand response is having on prices and reliability. The impacts on non-participants are less clear and not as readily available.

Generally limited to MISO, PJM, ISO-NE, and NYISO

The study focused on four Regional Transmission Operators (RTOs): the Midwest Independent Transmission System Operator, PJM Interconnection, ISO New England, and the New York Independent System Operator. It should be noted that information from MISO is very limited because, according to MISO representatives, ARCs are not yet participating in MISO markets.

Section 3: Study Findings

Background

Aggregators of retail customers (ARCs[3]) have been active participants in wholesale markets operated by PJM, ISO-NE, NYISO, and ERCOT for several years. In addition, ARCs have also signed numerous contracts with utilities and other load serving entities (LSEs).[4] ARCs are not currently participants in MISO markets.[5]

As of this writing, the Federal Energy Regulatory Commission (FERC) has not approved MISO's revisions to its Open Access Transmission, Energy and Operating Reserve Markets Tariff regarding the participation of ARCs in Midwest ISO's markets and, therefore, no ARCs are currently participating in MISO markets.[6] However, once FERC acts on the tariff change filing, ARCs will still be required to certify that the "law, regulations, order(s)" of the Relevant Electric Retail Regulatory Authority (RERRA) do not preclude such participation.[7]

FERC Order 719 includes an "opt out" provision for RERRAs. "An independent system operator or regional transmission organization must not accept bids from an aggregator of retail customers that aggregates the demand response of the customers of utilities that distributed more than 4 million megawatt-hours in the previous fiscal year, where the relevant electric retail regulatory authority prohibits such customers' demand response to be bid into organized markets by an aggregator of retail customers, or the customers of utilities that distributed 4 million megawatt-hours or less in the previous fiscal year, unless the relevant electric retail regulatory authority permits such customers' demand response to be bid into organized markets by an aggregator of retail customers." [8]

Nearly all of the states within MISO's footprint (Indiana, Iowa, Michigan, Minnesota, Missouri, North Dakota, South Dakota, Wisconsin) have issued regulatory decisions opting out of the FERC's requirement to allow ARC participation (see Appendix B for further information). The

[3] This report will use the Federal Energy Regulatory Commission term, ARCs, to describe aggregators of retail customers in its Order 719 - "Final Rule: Wholesale Competition in Regions with Organized Electric Markets," Federal Energy Regulatory Commission (Docket Nos. RM07-19-000 and AD07-7-000), October 17, 2008, p. 3.

[4] This report distinguishes between "utilities" which are defined as vertically-integrated utilities and "load serving entities" a term which includes utilities, but also includes retail electric providers in states that have implemented deregulation (restructuring).

[5] MISO formalized demand response participation in its markets with launch of the "Day 2" market in April 2005. "Demand Response in the Midwest ISO: An Evaluation of Wholesale Market Design," Sam Newell, Attila Hajos (The Brattle Group), Prepared fore the Midwest Independent System Operator, January 29, 2010, p. 8.

[6] "Midwest Independent Transmission System Operator, Inc. Filing re Aggregators of Retail Customers Docket No. ER09-1049-002," Midwest Independent Transmission System Operator, Federal Energy Regulatory Commission Docket No. ER09-1049-002, October 2, 2009.

[7] "Frequently Asked Questions: Aggregator of Retail Customers (ARC) Registration," Midwest Independent System Operator, p. 2.

[8] 18 Code of Federal Regulations §35.28(g)(1)(iii).

only MISO states that currently allow aggregators are Illinois, Ohio, and Indiana. All three of these states are served by both PJM and MISO, and Illinois and Ohio have deregulated their retail electricity markets. Indiana is the lone state within the MISO's footprint that allows ARC participation and has not deregulated its retail electricity markets.[9]

The distinction between states that have deregulated their retail electricity markets and those that have not is a very important one. For the most part, RTOs with very active ARC participation include states that have deregulated their retail electricity markets. This makes sense because the utilities in deregulated states are legally required to facilitate provision of retail electric service by competitive retail electric suppliers. As such, retail customers can also choose an ARC to provide curtailment services with fewer concerns about reliability, retail revenues/rates, and logistical issues because many of these issues have already been dealt with during the deregulation process. In addition, the RTOs have historically been actively involved in the deregulation process by ensuring that wholesale markets are designed to ensure efficient allocation of generation and curtailment resources and reliable service.

This study, therefore, focuses primarily on PJM, ISO-NE and NYISO. Although there is little opportunity to compare with MISO markets, it has become something of an accepted fact that increased levels of demand response within competitive wholesale markets have the potential to reduce overall prices and improve reliability.[10] This "fact" forms the foundation for the Federal Energy Regulatory Commission's recent Orders 719 and 745, which (among other objectives) aim to facilitate greater levels of demand response in organized wholesale electricity markets. To facilitate more demand response, Order 719 says that RTOs and ISOs have a duty to remove unreasonable barriers to treating demand response resources comparably with other resources.[11]

Prices

- Does demand response generally have an impact on prices?
- Can one draw distinctions between ARC and non-ARC participation in wholesale markets in order to explain potential differential impacts on prices?

What do we mean by prices?

This study focuses on wholesale electricity prices as opposed to retail prices. Wholesale prices refer to the price of electricity set by transactions in wholesale electricity markets that, for much of the United States, are organized by Regional Transmission Operators. "The balance of supply and demand and the cost to produce power essentially determine wholesale electricity prices."[12] There are three primary markets at the wholesale level: energy, capacity and ancillary services. Not all RTOs have formal markets for all three.

Most studies focus on the impact demand response has on energy prices. Wholesale energy markets include the day-ahead energy market in which resources and loads are bid and settled

---

[9] Note that Michigan has also deregulated its retail electricity market but prohibits ARCs (with the exception of certain PJM legacy contracts).

[10] These reports are listed in Appendix A.

[11] "Final Rule: Wholesale Competition in Regions with Organized Electric Markets," p. 150.

[12] "Wholesale Electricity Markets," ISO New England, http://www.iso-ne.com/img/wem.pdf, August 7, 2011

the day ahead of the real-time market. As compared to real-time energy, this market provides greater certainty for suppliers and consumers of electricity and ensures that fewer transactions occur in the more volatile real-time market. Real-time energy is the balancing settlement for the quantity deviations from each participant's day-ahead energy market obligations whereas the real-time energy market is a spot market in which current prices are calculated at intervals (usually five minute) based on actual grid operating conditions.

Demand response can also affect prices for capacity and ancillary services, but these do not get as much attention. As described in a report about PJM,

> The effects of demand response on energy prices are often discussed, but the potential effects on capacity prices are rarely mentioned. Demand response could reduce capacity prices by reducing peak loads and therefore reducing the demand for capacity, as determined by PJM's resource adequacy requirements. If the demand for capacity is reduced, then the capacity market could clear at a lower price, particularly if the demand reduction shifts the market balance from a capacity scarcity to a capacity surplus.[13]

In the past, demand response, particularly utility interruptible programs, has been frequently evaluated based on its ability to provide lower cost capacity. Utility integrated resources plans have long incorporated interruptible capacity because it tends to be lower cost than peaking generating units.[14] But the more recent focus has shifted to demand response's effects on energy prices because demand response is viewed as a potential proxy for dynamic pricing. Many economists and regulators consider full implementation of dynamic retail electricity pricing (also referred to as "price responsive demand" or PRD) to be the ultimate goal, with demand response programs as a bridge to this goal.[15]

Demand response's effects on the cost for ancillary services is not well known, largely because demand response has only recently begun to provide ancillary services. In addition, capacity and ancillary services are considered reliability products. They will be discussed further in the section on reliability.

What impacts do ARC operations have on prices?

As discussed, there is insufficient quantitative data to directly determine the impact of ARCs on prices. That said, we can answer the sub-question, "Does demand response generally have an

[13] "Quantifying Demand Response Benefits In PJM," Prepared by The Brattle Group for the PJM Interconnection and the Mid-Atlantic Distributed Resources Initiative (MADRI), January 29, 2007, p. 27.

[14] IRP presents price effects in terms of "avoided costs". A recent study for the Avoided-Energy-Supply-Component (AESC) Study Group examined such costs for New England and incorporated the latest information from ISO-NE's energy and capacity markets. "Avoided Energy Supply Costs in New England: 2011 Report," Prepared for the Avoided-Energy-Supply-Component Study Group by Synapse Energy Economics, July 21, 2011.

[15] *See* "Price Responsive Demand," *PJM Staff Whitepaper*, March 3, 2011; "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005," U.S. Department of Energy, February 2006; "Fostering Economic Demand Response in the Midwest ISO," Prepared for the Midwest Independent Transmission System Operator by The Brattle Group, December 30, 2008.

impact on prices?" There is general consensus that demand response successfully reduces wholesale energy prices, at least in the short run, and it also can help reduce prices for (or "the cost of," if not market provided) capacity and ancillary services. In these cases, demand side resources have proven to be obtainable at lower prices than marginal generation sources. As stated in a recent article by the current Chairman of the Federal Energy Regulatory Commission,

> FERC has recognized a number of benefits associated with participation by demand response in the organized markets. Addressing one important benefit, FERC has stated that demand response helps to reduce prices in competitive wholesale markets in at least three ways. First, when demand response is bid directly into a wholesale market, the lower demand means a lower wholesale price. Second, demand response tends to flatten an area's load profile, thereby reducing the need to use more costly resources during periods of high demand and lowering the overall average cost to produce energy. Third, demand response reduces generator market power. The more demand response that is available during peak periods, the more downward pressure it places on generator bidding strategies by increasing the risk to a power supplier that it will not be dispatched if it submits too high a bid (FERC 2008a, P 29-31).
>
> The benefits stemming from demand response, however, go beyond reductions in wholesale prices. For example, FERC has stated that demand response enhances reliability and supports the use of renewable energy resources (FERC 2008a, P 27).[16]

As evidenced by the rise of demand side management (DSM) and least cost resource planning (integrated resource planning or IRP) in the 1970s, this conclusion is not a new realization. The National Energy Conservation Policy Act of 1978 "was an acknowledgment that saving energy could be cheaper than producing it" and many states followed suit by requiring utilities to implement DSM programs and IRPs.[17]

What is new is the rise of a new class of market participants called aggregators of retail customers and integration of demand response into wholesale markets. In fact, ARCs have existed since the inception of RTO demand response programs in the late 1990s; however, their role in wholesale markets has increased markedly over the last several years, particularly as Northeastern RTOs have created opportunities for greater participation. FERC has adopted the view that:

> Aggregating small retail customers into larger pools of resources expands the amount of resources available to the market, increases competition, helps reduce prices to consumers and enhances reliability…We also agree with commenters

---

[16] "Creating Regulatory Structures for Robust Demand Response Participation in Organized Wholesale Electric Markets," Hon. Jon Wellinghoff, David L. Morenoff, James Pederson, Mary Elizabeth Tighe, Federal Energy Regulatory Commission, 2008 ACEEE Summer Study, p. 2.

[17] "The Past, Present, and Future of U.S. Utility Demand-Side Management Programs," Joseph Eto, Environmental Energy Technologies Division Ernest Orlando Lawrence Berkeley National Laboratory, December 1996, p. 5.

> that (aggregation) could encourage development of demand response programs and thereby provide retail customers more opportunities available through larger markets.[18]

Two RTOs, ISO-NE (since 2003) and NYISO (since 2001) with large amounts of ARC participation are required to submit reports to the Federal Energy Regulatory Commission documenting the effects demand response has had on prices. The two RTOs estimated demand response impacts on energy prices using their day-ahead demand response programs. ISO-NE ran simulations using participation in its Day-Ahead Load Response Program (DALRP) to estimate what real-time prices would have been had been with and without interruptions. NYISO analyzed actual schedules, loads and prices using participation in its Day-Ahead Demand Response Program (DADRP). See Appendix C for a detailed description of RTO demand response activities.

ISO-NE's DALRP is an optional program that allows a participant in the RTPR (Real-Time Price Response) program to offer interruptions concurrent with the Day-Ahead Energy Market. Participants in the DALRP are paid the Day-Ahead LMP for the cleared interruptions, and Real-Time deviations are charged or credited at the Real-Time LMP.[19]

From the December 2010 ISO-NE report,

> During the first two months of the Reporting Period, the Load Response Program reduced real-time LMPs by approximately $0.61/MWh across the entire wholesale market in New England. The largest average decrease, $0.87/MWh, was seen in Connecticut. During the latter four months of the Reporting Period, due in part to a tenfold increase in interrupted MWh per month, the program reduced real-time LMPs by approximately $1.72/MWh across the entire market, with the largest average decrease of approximately $2.15/MWh seen in Maine ... (These reductions in prices) decreased energy costs charged to load in the New England region by about $8.8 million during the Reporting Period.[20]

The most recent NYISO report provides a summary of the DADRP's estimated impacts since 2001,[21]

---

[18] "Order 719," pp. 83-84.

[19] "Semi-Annual Status Report on Load Response Programs of ISO New England Inc., Docket No. ER03-345-," ISO New England, December 30, 2010 p. 3.

[20] The reporting period was April-September 2010. "Semi-Annual Status Report on Load Response Programs of ISO New England Inc., Docket No. ER03-345-," p. 12. Although 2009 was not as active a year for demand response as 2008, the results from 2008 were not appreciably different.. Estimates in price reductions did not account for potential increases in load that occurred in non-event periods due to load shifts from event to non-event periods.

[21] "Annual Report in Docket Nos. ER01-3001-000," New York Independent System Operator, Submitted to the Federal Energy Regulatory Commission (Docket No. ER01-3001-000), January 18, 2011, p. 27.

Figure 1 – NYISO Day Ahead Demand Response Program Summer Price Reductions

Table 10: DADRP Average Price Reductions (Summer Season)

	Scheduled DADRP MWh	Program Payments		Average Price Reduction ($)		Average Hourly Schedule (MWh)
2001	2,694	$	217,487	$	0.58	5.07
2002	1,468	$	110,216	$	0.30	6.99
2003	1,752	$	121,144	$	0.12	2.79
2004	675	$	40,651	$	0.07	3.04
2005	829	$	77,885	$	0.10	4.02
2006	295	$	29,821	$	0.05	1.53
2007	765	$	64,737	$	0.04	1.67
2008	3,177	$	348,509	$	2.05	1.71
2009	28	$	2,605	$	-	1.00
2010	20	$	-	$	-	5.00

> The DADRP program provides demand resources with an opportunity to offer their load curtailment capability into the Day-Ahead energy market as energy supply resources. Resources submit offers by 5:00 a.m., specifying the hours and amount of load curtailment they are offering for the next day, and the price at which they are willing to curtail … the offer floor price for DADRP has been set at $75/MWh. Offers are structured like those of generation resources, so DADRP program resources may specify minimum and maximum run times and effectively submit a block of hours on an all-or-nothing basis … Load scheduled in the DAM is obligated to curtail the next day. Failure to curtail results in the imposition of a penalty equal to the product of the MW curtailment shortfall and the greater of the corresponding Day-Ahead and Real-Time market price.[22]

NYISO sets a floor price to "prevent a DADRP Resource from submitting low bids for periods of time when its load would already be off-line for maintenance or regularly scheduled shutdowns, thus discouraging free-ridership and bidding behavior that provides no real benefit."[23] In Figure 1, Scheduled DADRP MWh is the sum of all scheduled DADRP during the analysis period while payments are the sum of the scheduled MWh in a specific hour multiplied by the day-ahead locational market price. Average price reduction represents the estimated impact that the DADRP performance had on the day-ahead locational market price.[24]

ARCs are not significant players in NYISO's DADRP, instead focusing on the reliability programs. The following graph shows the percentage of total participation for the DADRP by provider type.

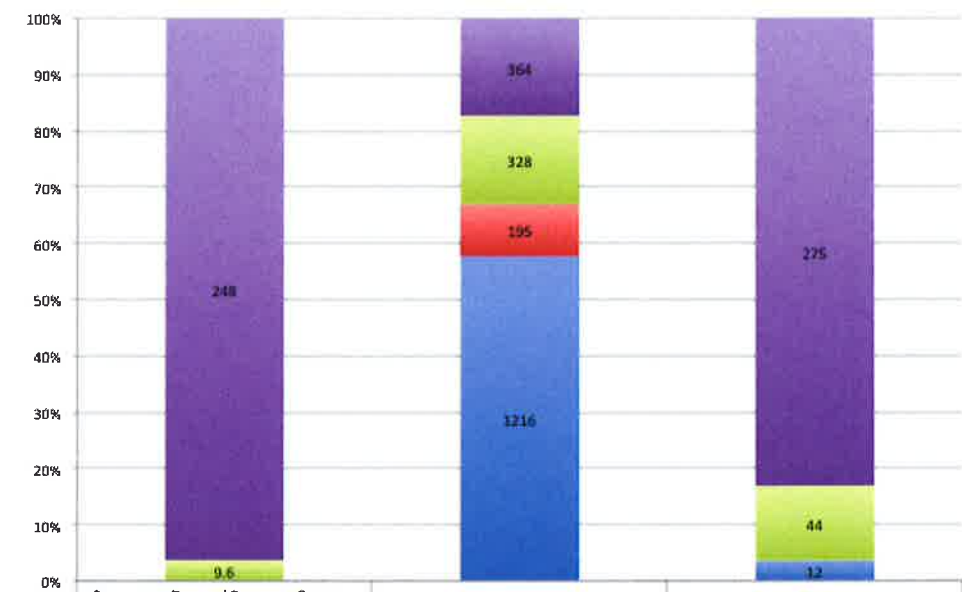
---

[22] "Annual Report in Docket Nos. ER01-3001-000," p. 18.

[23] "Letter Order to NYISO," Federal Energy Regulatory Commission (Docket No. ER04-1188-000), October 29, 2004, p. 1.

[24] "Compliance Filing in Docket Nos. ER01-3001-, ER03-647-," New York Independent System Operator, Submitted to the Federal Energy Regulatory Commission (Docket No. ER01-3001-000), January 15, 2009, p. 23.

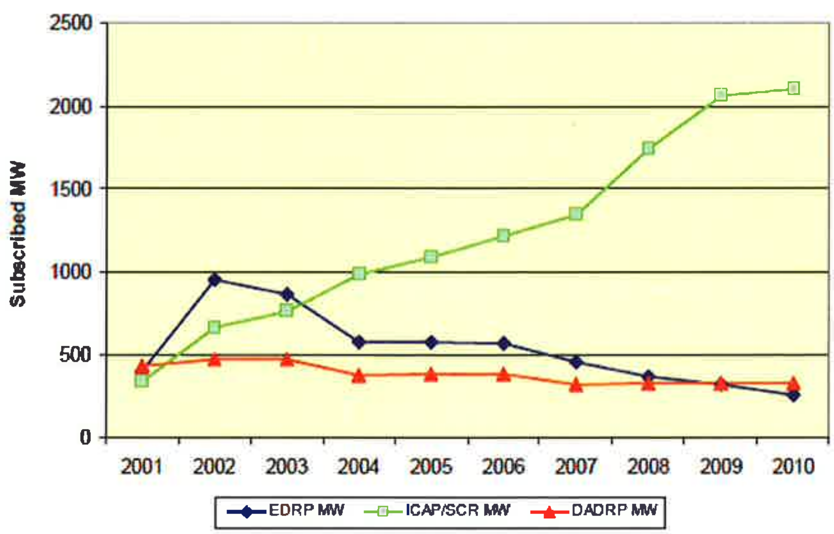
Figure 2 - NYISO 2010 DR Program Participation by Provider Type (megawatts and % of total)[25]



	Emergency Demand Response Program (EDRP)	Installed Capacity Market	Day-Ahead Demand Response Program
Transmission Owner	248	364	275
LSE	9.6	328	44
Direct Customer		195	
Aggregator		1216	12

Overall participation (MW) in NYISO's DADRP has remained fairly steady over the years while participation in its ICAP/SCR program has increased nearly every year (see Figure 3).

Figure 3 – NYISO Demand Response Program Enrollment 2001-2010 (MW)



[25] Annual Report in Docket Nos. ER01-3001-000," January 18, 2011, p. 9.

The scope of the instant report did not provide the opportunity to fully analyze the reasons for this shifts between programs, but according to the NYISO the shift from its Emergency Demand Response Program (EDRP) to the ICAP/SCR program is at least partly due to the monthly reservation payment associated with the ICAP/SCR program.[26]

PJM does not have any reporting requirements similar to those for ISO-NE and NYISO, but PJM commissioned a study in 2007 from the Brattle Group to quantify demand response benefits.[27] The study used "a simulation-based approach to quantify the market impact of curtailing 3% of load in the BGE, Delmarva, PECO, PEPCO, and PSEG zones during the top twenty 5-hour price blocks in 2005 and under a variety of alternative market condition."[28] The simulations determined that:

- Curtailing 3% of each selected zone's super-peak load, which reduces PJM's peak load by 0.9%, yields an energy market price reduction of \$8-\$25 per megawatt-hour, or 5-8% on average, during the 133-152 hours in which curtailment occurs in at least one zone. The range depends on market conditions.
- Assuming all loads (i.e., customers or their retail providers) are exposed to spot prices, the estimated price reductions could benefit non-curtailed loads in MADRI states by \$57- \$182 million per year. The potential benefits to the entire PJM system amount to \$65- \$203 million per year.[29]

The estimated values from the PJM study are much higher than those estimated by ISO-NE and NYISO, likely due to the megawatts of demand response used in the PJM study as compared to the actual amounts registered in ISO-NE and NYISO. The ability to curtail 3 percent of a region's super-peak load would have a demonstrably larger effect than the approximate 1 percent (author's estimate) of load actually available for day-ahead scheduling in NYISO, ISO-NE and PJM.

The study did not segregate ARCs from other market participants. PJM does not break out the different types of "curtailment service providers" that participate in its demand response programs.

In *Fostering Economic Demand Response in the Midwest ISO*, the Brattle Group reported that, "comments from FERC and the RTOs, publicly available data on CSPs, and our interviews with the three largest CSPs indicate that CSPs contribute a large fraction, if not the majority, of DR in PJM and ISO-NE, as well. This could, in fact, be due to the retail choice environments prevalent in the East, whereas, MISO has mostly a regulated rate environment."[30] This may be true but PJM representatives point out that a number of utilities (local distribution companies or LDCs)

---

[26] "Annual Report in Docket Nos. ER01-3001-000," p. 14.

[27] "Quantifying Demand Response Benefits In PJM."

[28] "Quantifying Demand Response Benefits In PJM," p. 2.

[29] "Quantifying Demand Response Benefits In PJM," p. 2.

[30] "Fostering Economic Demand Response in the Midwest ISO," Prepared for the Midwest Independent Transmission System Operator by The Brattle Group, December 30, 2008, 53.

are also active participants. These LDCs include Baltimore Gas & Electric (MD), Commonwealth Edison (IL), and Public Service Electric & Gas (NJ).

Thus, given the impact of demand response on prices and the participation of ARCs in demand response activities, it is likely that ARC operations have had an impact on prices but this value is difficult to quantify. The one RTO (ISO-NE) that provides information about participants in its day-ahead market indicates that ARCs are not very active in this market.

Claims by ARCs, utilities, and others about ARC participation

In conducting research, the authors sought information from a selection of aggregators. The aggregators were also not aware of existing studies that segregated ARC participation from other market participants but pointed to studies that demonstrated the effects demand response can have on wholesale market prices. In addition, aggregators highlighted the fact that much of the new demand response participation in wholesale markets, particularly in the Northeast, is from aggregators. Considering the increasing role aggregators are playing in wholesale markets, aggregators believe that a persuasive argument can be made that, to the extent that demand response impacts (lowers) prices, that aggregators are the primary causes of these impacts because of their role in the market.

This may be true, but it is a difficult claim to confirm without true quantitative studies that segregate ARCs from other participants. By the same token, it very well may be true that non-ARC participants in wholesale markets would have the same impacts on prices. In this sense, the issue isn't so much the impact ARCs have on prices (or reliability) but rather is the active participation of ARCs a necessary feature for wholesale markets to benefit from demand response?

In Order 719, FERC comes down strongly in support of RTOs facilitating greater amounts of ARC participation in wholesale markets, and one can assume that this support is heavily aimed at RTOs that do not currently have large amounts of ARC participation (MISO, Southwest Power Pool, California Independent System Operator). For its part, MISO has commissioned a number of recent studies to examine ways MISO can improve its markets for participation by demand response and energy efficiency resources (among other changes).[31]

These studies conclude that MISO markets would benefit from more active demand side participation while acknowledging that MISO currently has a fairly large demand side resource, mainly from legacy utility interruptible programs. The Brattle Group's *Fostering Economic Demand Response in the Midwest ISO* comes down strongly in favor of increasing price-responsive demand response in the Midwest and recommends that MISO enable "participation of curtailment service providers (CSPs) in its energy markets as at least a bridge to a future in

[31] *See* "Fostering Economic Demand Response in the Midwest ISO; "Midwest Retail Demand Response Program Survey Results," by Chuck Goldman, Ranjit Bharvirkar, Grayson Heffner, Lawrence Berkeley National Laboratory for the Midwest Demand Response Initiative (MWDRI), March 7, 2008; "Demand Response in the MISO: An Evaluation of Wholesale Market Design," Sam Newell, Attila Hajos, The Brattle Group for the MISO (MISO), January 29, 2010; "Assessment of Demand Response and Energy Efficiency Potential for MISO," Global Energy Partners, LLC, Report #1314, November 2010.

which the states enable the first-best approach to economic DR by implementing widely retail rates with dynamic pricing."[32]

The study goes on to say that, "CSPs can provide expertise, technology, and a willingness to take risk that many utilities lack. LSEs and CSPs are not necessarily in competition with each other. For example, CSPs may be able to approach more customers that LSEs find difficult to manage. Furthermore, working through LSEs may reduce the CSPs' marketing costs."[33]

The same study, though, acknowledges that Minnesota ranks highest among MISO states in terms of "likelihood of producing significant DR impacts" and does not point to Minnesota as one of the states where "CSPs can help to fill those gaps."[34] The study also suggests that increasing levels of price-based demand response in the Midwest can be accomplished in three different ways: 1) load serving entities should move retail customers to time-based pricing, 2) LSEs and possibly third parties (ARCs) should bid price responsive demand curves into wholesale markets and/or 3) demand response should be bid as a supply resource into the wholesale market.[35] In other words, ARCs can be part of the solution but so, too, can utilities.

But there is another important point that should not be lost in the discussion of demand response, prices and ARCs. *Fostering Economic Demand Response in the Midwest ISO* and similar studies emphasize the value of demand response as a proxy for dynamic pricing and consider key to this demand response programs that can directly impact day-ahead and real-time energy prices. However, demand response programs that affect day-ahead and real-time energy markets are <u>not</u> well subscribed (relative to capacity programs) and whether or not ARCs are active participants in these programs may not be as important as the fact that overall participation is not very robust.

Reliability

- Does demand response generally have an impact on reliability?
- Can one draw distinctions between ARC and non-ARC participation in wholesale markets in order to explain potential differential impacts on reliability?

What is reliability?

The North American Electric Reliability Corporation (NERC) defines the reliability of the interconnected bulk power system in terms of two basic and functional aspects:

- Adequacy — The ability of the bulk power system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

[32] "Fostering Economic Demand Response in the Midwest ISO," p. 3.

[33] "Fostering Economic Demand Response in the Midwest ISO," p. 55.

[34] "Fostering Economic Demand Response in the Midwest ISO," pp. 71-74.

[35] "Fostering Economic Demand Response in the Midwest ISO," pp. 2-3.

- Security — The ability of the bulk power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements from credible contingencies.[36]

NERC develops standards for reliability planning and the reliable operation of the bulk power systems. The Energy Policy Act of 2005 added Section 215 to the Federal Power Act to establish a framework for making reliability standards mandatory for all bulk power system owners, operators and users.

Demand response and reliability

Demand response can effectively help satisfy requirements for adequacy and security. According to NERC, in "addition to providing capacity for resource adequacy and planning purposes, capacity and ancillary services provided by Demand Response helps ensure resource adequacy while providing operators with additional flexibility in maintaining operating reliability. However, Demand Response is still a relatively new resource, and both NERC and stakeholders need to measure its performance in order to gauge its benefits and impacts on reliability. Better performance measures will also help develop industry confidence in Demand Response use."[37]

Although utilities have historically used demand response to help ensure the reliable operation of the grid, this responsibility has shifted to RTOs in many regions. RTOs are in the process of integrating demand response (and energy efficiency) into their activities to ensure both short-term and long-term reliability. RTOs are following the requirements of Section 1252(f) of the Energy Policy Act of 2005 which states that "deployment of such technology and devices that enable electricity customers to participate in such pricing and demand response systems shall be facilitated, and unnecessary barriers to demand response participation in energy, capacity and ancillary services markets shall be eliminated."[38]

Demand response can participate in two reliability related markets: ancillary services and capacity. Ancillary services act as an insurance policy against the unforeseen loss of a major power plant or transmission line and basically keep the electrical system in balance. Procurement of such services can be cost-base or market-based. Ancillary services include:

- **Forward and Real-Time Operating Reserves** - ensure that sufficient resources are held in "reserve" and are available to produce electricity on short notice when an outage or another problem occurs. These can be provided by demand response.

[36] http://www.nerc.com/page.php?cid=1|15|123. The Bulk Power System refers to the "part of the overall electricity system that includes the generation of electricity and the transmission of electricity over high-voltage transmission lines to distribution companies. This includes power generation facilities, transmission lines, interconnections between neighboring transmission systems, and associated equipment. It does not include the local distribution of the electricity to homes and businesses."

[37] http://www.nerc.com/page.php?cid=4%7C357. Accessed on August 8, 2011.

[38] "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005," U.S. Department of Energy, February 2006.

- **Regulation** - allows RTOs to instruct specific power plants to increase or decrease output moment-by-moment to balance system frequency, which must always be kept at a constant rate. Demand response can provide regulation services.
- **Voltage Support** - allows the system operators to maintain transmission voltages within acceptable limits. Demand response is not generally used for voltage support.
- **Black-Start Capability** - is provided by specific power plants at strategic locations and involves restoring generation to restart the transmission system following a system wide blackout. Demand response is not generally used for black-start capability.[39]

"Capacity markets compensate supply resources and demand resources either for the electricity they are capable of producing if needed—or in the case of demand resources, for the electricity they avoid using—to ensure that enough electricity capacity exists to meet regional reliability requirements."[40]

Ancillary services and capacity are not always procured through markets but rather may also be obtained through bi-lateral contracts between entities responsible for maintaining reliability (RTOs, utilities) and providers of such services. RTOs are still in the process of implementing markets for all types of ancillary services and some RTOs (such as the MISO) don't have capacity markets.[41] In RTOs that do not have capacity markets, RTOs rely upon load serving entities to ensure sufficient levels of capacity to meet demands.

Demand response and energy efficiency are playing increasingly important roles in providing ancillary services and capacity due to each resource's flexibility, cost, environmental attributes and speed of implementation. In Order 719, FERC required RTOs to accept bids from demand response providers for ancillary services on a comparable basis with other resources as long as the demand response resources could meet technical specifications.[42] RTOs with formal capacity markets, including ISO-NE, PJM and NYISO, now allow participation by demand response resources (and in ISO-NE and PJM's cases, energy efficiency). This is to say that demand response services play active roles in delivering both short-term and long-term reliability. The graphic below depicts these roles relative to other resources.

---

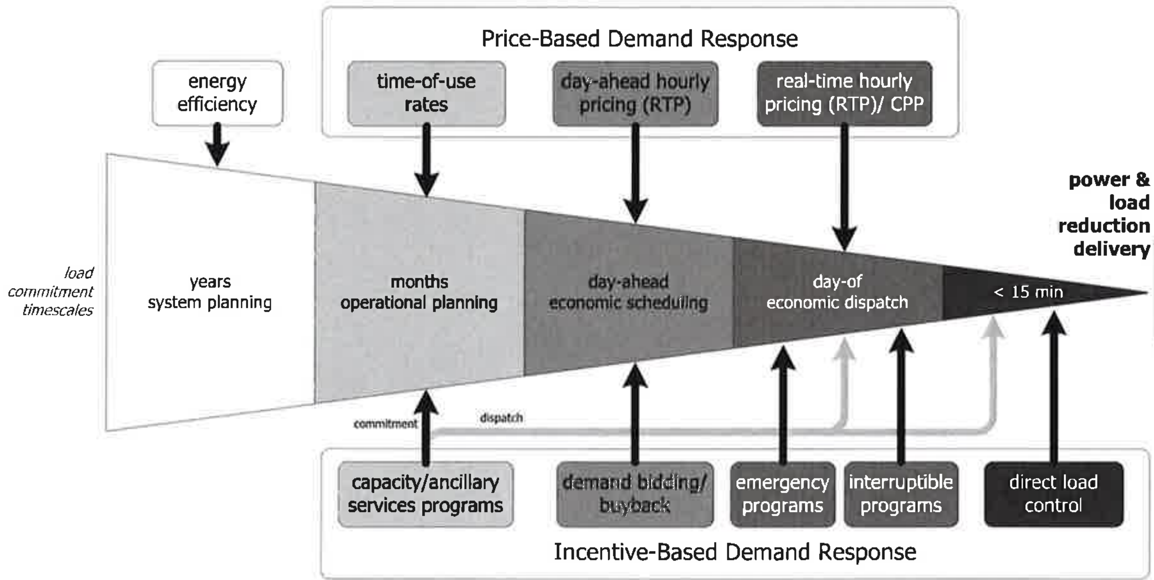
[39] "Wholesale Electricity Markets," ISO New England, http://www.iso-ne.com/img/wem.pdf, accessed on August 8, 2011.

[40] Ibid.

[41] MISO recently filed with FERC its "enhanced resource adequacy construct" (Midwest Independent Transmission System Operator, Inc. Filing to Enhance RAR By Incorporating Locational Capacity Market Mechanisms; FERC Docket Nos. ER08-394-004; ER08-394-005; ER08-394-021; ER08-394-022; ER08-394-028; ER08-394-029; and ER11-___ -000, July 20, 2011). The construct proposes to establish a short-term capacity market (1 year) but provides opportunities for LSEs in non-retail choice states to "opt out" of the auction.

[42] "Final Rule: Wholesale Competition in Regions with Organized Electric Markets, Docket Nos. RM07-19-000 and AD07-7-000," Federal Energy Regulatory Commission, p. 27.

Figure 4 - Role of Demand Response Electric System Planning and Operation[43]



What impact do ARCs have on reliability?

Demand response is increasingly relied upon by RTOs to provide ancillary services and capacity and, therefore, demand response is playing a very important role in ensuring the reliability of the electricity system. In an effort to systematically quantify the effects demand response has on reliability, NERC created the Demand Response Availability Data System (DADS). According to NERC,

> Demand response is one of many resources needed to satisfy the increasing demand for electricity in North America. In addition to providing capacity for resource adequacy and planning purposes, capacity and ancillary services provided by Demand Response helps ensure resource adequacy while providing operators with additional flexibility in maintaining operating reliability. However, Demand Response is still a relatively new resource, and both NERC and stakeholders need to measure its performance in order to gauge its benefits and impacts on reliability...The goal of the DADS is to collect Demand Response enrollment and event information to measure its actual performance including its contribution to improved reliability. Ultimately, this analysis can provide industry with a basis for projecting contributions of dispatchable and non-dispatchable (e.g., price-driven) Demand Response supporting forecast adequacy and operational reliability. [44]

[43] "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005," U.S. Department of Energy, p. 15.

[44] http://www.nerc.com/page.php?cid=4%7C357, accessed on August 25, 2011.

NERC is in the process of implementing the mandatory "Phase II" of DADS and expects to have semi-annual reports that will include statistics and metrics to assess demand response's impacts on reliability and resource adequacy. Submitted data will be treated as confidential information.

But, again, there is an issue with distinguishing ARC contribution to reliability relative to other players in the market. Although one can make a persuasive argument that ARCs, because of their very active participation in ISO-NE, PJM and NYISO ancillary services and capacity markets, contribute significantly to reliability, it is not easy to distinguish the contribution that ARCs make vis-à-vis other players.

Starting with the 2007/8 delivery year, demand side resources can participate in PJM's Reliability Pricing Model (RPM).[45] RPM is PJM's capacity-market model. Designed to create long-term price signals to attract needed investments in reliability, PJM requires that participants make capacity commitments three years ahead. For the 2012/13 planning year, demand response is expected to provide over 5% of the total cleared capacity resources, a value that increases to 9.4 percent for the 2014/2015 planning year.[46] Although PJM does not break out the portion of its demand response resources that are provided by ARCs vs. other entities, it appears that ARCs are very active participants in this market, too.

ARCs are the majority of participants in NYISO's reliability programs. According to its report to FERC, of the 56 Curtailment Service Providers (CSPs) and Responsible Interface Parties[47] participating in the ISO's Emergency Demand Response Program (EDRP) and ICAP/SCR (Installed Capacity/Special Case Resource) program, 7 were transmission owners, 6 were load-serving entities not affiliated with a Transmission Owners, 31 were aggregators that were not load serving entities or transmission owners and 12 were direct resources (typically large end-use customers).[48]

The demand response resources in NYISO reliability programs represent 7.0% of the 2010 Summer Capability Period peak demand of 33,452 MW, an increase of 0.7% from 2009. As shown in Figure 2, in 2010 aggregators constituted a majority (~57%) of MW registered in the ICAP but a much small percentage (~2%) in the Emergency Demand Response Program.

MISO currently meets its capacity requirements by obligating LSEs to have sufficient capacity to meet demands. Demand response resources can be used by LSEs to meet their Module E (reliability section of MISO tariff) requirements. These capacity resources are fairly substantial with approximately 10,000 MW registered as of April 2011.[49] Since there are no participating ARCs, these resources are provided entirely by utilities or end-use customers. ARC participation

[45] Demand side resource participation actually started with the 2005/6 delivery year but the RPM was implemented for the 2007/8 delivery year.

[46] "RPM Offers by Commitment and Fuel Type," http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx, PJM, May 25, 2011. Accessed on August 8, 2011.

[47] Responsible Interface Parties are a subset of NYISO participants within the Installed Capacity Market who can receive energy and capacity payments.

[48] "Annual Report in Docket Nos. ER01-3001-000," p. 6.

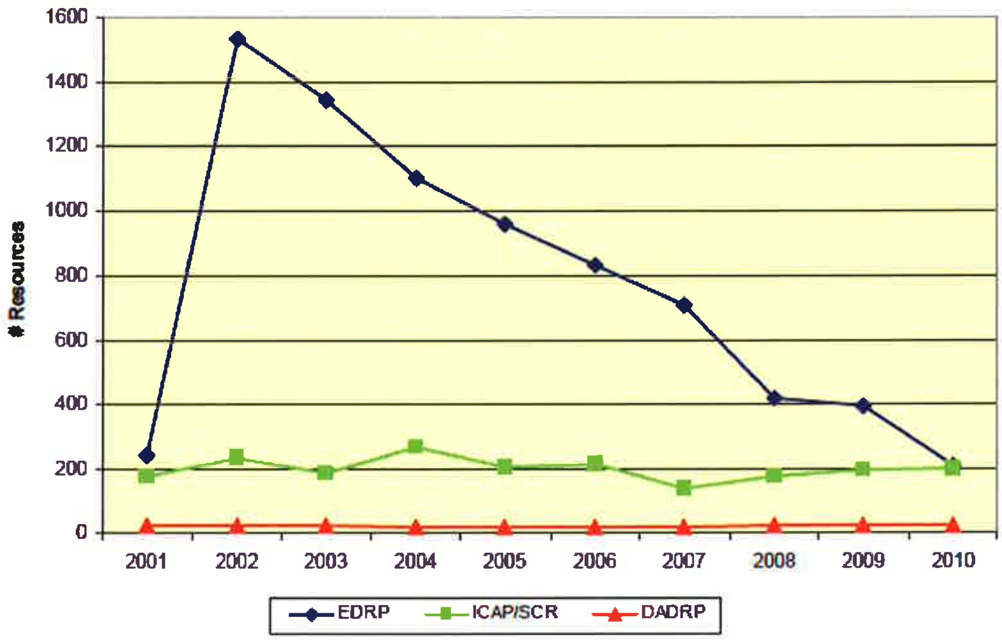
[49] "Demand Participation Update," Demand Response Working Group, Midwest ISO, April 4, 2011, p. 2.

may change these values, although it is not obvious whether the amount of participating load would increase or decrease. Due to differences with respect to retail regulation, the Northeastern RTOs are not necessarily analogous to the Midwest ISO.

Evolving ARC preferences as they relate to reliability

ARCs are clearly very active participants in capacity markets in the Northeastern RTOs. In fact, ARCs appear to be focusing heavily on capacity markets (as opposed to day-ahead and real-time energy markets). In the New York ISO, as of 2010, only three resources representing thirty locations submitted load reduction offers in the Day-Ahead Demand Response Program. In addition, "Offer activity decreased by 70% over the previous 12-month period and 87% fewer hours were scheduled (134) than in the previous period (1,067)."[50] At the end of August 2010, the NYISO's reliability programs had a total of 4,386 end-use locations enrolled, providing a total of 2,362.1 MW of demand response capability, a less than 1% decrease over the 2009 MW enrollment level.[51] (see table below)

Figure 5 - NYISO Demand Response Program Enrollment History 2001-2010[52]



This appears to have happened because ARCs find capacity market opportunities attractive due to guaranteed payments and likely limited numbers of interruptions. In addition, payments from capacity markets help compensate ARCs for investments they may have made in marketing,

[50] "Annual Report in Docket Nos. ER01-3001-000," p. 7.

[51] "Annual Report in Docket Nos. ER01-3001-000," p. 7.

[52] "Annual Report in Docket Nos. ER01-3001-000," p. 15.

systems, etc. to sign-up and activate customer demand response. In contrast, utilities that run demand response programs can usually recover acquisition and systems costs through rates.[53]

Nonparticipating customers

- Would nonparticipating customers be impacted differently from ARC vs. non-ARC demand response programs?
- Is it possible to determine whether the benefits of ARCs exceed their costs?

Why are nonparticipating customers important?

The term "nonparticipating customers" refers to the customers within a particular area (usually a utility service territory but could also pertain to an area served by an RTO running a demand response program) that do not participate in the relevant demand response program. These customers are of interest because a basic principle of the use of demand response is that its benefits to the grid or market as a whole are greater than the total cost of securing demand response load reduction. Thus, if demand response program costs (including payments to participating customers) associated with load reductions exceed the overall financial benefits to the particular area, the nonparticipating customers could end up subsidizing participating customers because these costs need to be recovered from all customers, including nonparticipating customers. In addition, if reduction in energy use limits the load serving entity's ability to recover its fixed costs (without lowering these costs), the utility must raise rates for all customers to recover the costs.

DR and nonparticipating customers

The authors found no available quantitative data regarding the effects of ARCs on nonparticipating customers; however, to the extent that ARCs receive the same compensation as any other demand response participant or ARC compensation is designed to not increase overall costs, this issue is best addressed by prudent demand response design and implementation. FERC's opinion on the matter is clear and RTOs and utilities are using FERC's direction as a basis for demand response design.

In its Order 745, FERC attempted to resolve this issue, at least as it pertains to wholesale transactions. As the Commission states,

> "[D]ispatching demand response resources may result in an ***increased cost per unit to load associated with the decreased amount of load paying the bill,*** depending on the change in LMP relative to the size of the energy market. ... [T]his is the billing unit effect of dispatching demand response resources. ...[***W]hen reductions in LMP from implementing demand response results in a reduction in the total amount consumers pay for resources that is greater than the money spent acquiring those demand response resources at LMP***, such a payment is a cost-effective purchase from the customers' standpoint. In comparison, when wholesale energy market customers pay a reduced price attributable to demand response that does not reduce total costs to customers more

[53] Between rate cases, however, a utility as well may incur costs that are not recoverable and so may have similar incentives as ARCs.

> than the costs of paying LMP to the demand response dispatched, customers suffer a net loss." [54] (***emphasis*** added)

This order resulted in the so-called "net benefits" test. Order 745 directs "each RTO and ISO to develop a mechanism as an approximation to determine a price level at which the dispatch of demand response resources will be cost-effective."[55] The net benefits test and payment of LMP for demand response is not without controversy, though.

The Organization of MISO States (OMS) in its Request for Rehearing of Order 745 contends that FERC's determination is "not just and reasonable because it will result in excessive compensation for certain demand response resources" and that the net benefits test "will preclude the deployment of demand response resources at certain times when it would otherwise be efficient to do so."[56] OMS also says that, by pushing the handling of the retail rate component of demand response compensation back to the states, FERC could be imposing "complex and costly changes to billing and metering systems" to facilitate "charging the retail rate to participating customers for load reductions."[57]

In the MISO states that are still under traditional ratemaking schemes and have vertically integrated utilities, only one has thus far opted to allow aggregator participation. In this state, Indiana, the Indiana Utility Regulatory Commission authorized aggregator participation in PJM and MISO wholesale demand response programs (the state includes utilities in both RTOs) through IURC-approved utility tariffs. The utilities have subsequently issued and the IURC has approved these tariffs.

The approved tariffs for Duke Energy Indiana, Inc. and Northern Indiana Public Service Company (NIPSCO) provide opportunities for ARCs to participate in PJM and MISO demand response opportunities. The tariffs compensate ARCs with whatever compensation the utility receives through the demand response activity and then reduce this amount by the Marginal Foregone Retail Rate (MFRR) along with a 5 percent administrative fee. The Marginal Foregone Retail Rate is defined as "the full marginal retail rate inclusive of trackers excluding any demand component effects."[58]

Presumably, this rate structure will help ensure that non-participating retail customers will be held harmless by customer participation in wholesale markets through ARCs. It remains to be seen whether ARCs will actively participate in these programs or what types of implications ARC participation may have for other Indiana utility demand response programs. It should be

---

[54] "Demand Response Compensation in Organized Wholesale Energy Markets," (Docket No. 17-000, Order No. 745), Federal Energy Regulatory Commission, p. 41.

[55] "Demand Response Compensation in Organized Wholesale Energy Markets," p. 4.

[56] "Request for Rehearing of the Organization of MISO States," by Organization of MISO States, Federal Energy Regulatory Commission (Docket No. RM10-17-000), April 14, 2011, p. 2.

[57] "Demand Response Compensation in Organized Wholesale Energy Markets," p. 5.

[58] "Standard Energy Contract Rider No. 22: Duke Energy Market Based Demand Response (MBDR) Rider Applicable to HLF and LLF Rate Groups," Indiana Utility Regulatory Commission (IURC) Cause No. 43566, Approved March 2, 2011.

noted that Indiana only recently revived efforts to implement utility energy efficiency and currently has modest levels of utility demand response activity.[59]

Conclusions about DR and nonparticipating customers

Demand response can have a positive effect on nonparticipating customers as well as participating customers if compensation parameters are correctly established. FERC Order 745 attempted to craft a compensation scheme so that nonparticipants would not be harmed, at least at the wholesale level, but as discussed herein, it is clear that this matter is not fully resolved. Therefore, this issue may still be left to retail regulators to sort out.

Inferences about ARCs based on DR data

It is difficult to make inferences about ARC impacts on non-participating customers based on general demand response data; however, ARC participation in wholesale markets highlights concerns about effects on nonparticipants because FERC's Order 745 requires that RTOs pay demand-response providers the locational marginal price (LMP), if the DR resource can (a) balance supply and demand and (b) satisfy FERC's cost-effectiveness test. ARCs (and large customer groups) were the primary groups advocating before FERC for payment of LMP. Others contended that payment of LMP without compensating LSEs for reduction in retail payments creates a subsidy to participants/ARCs that is economically inefficient.[60]

Regardless of Order 745, potential negative effects on nonparticipants should be remedied in a regulated retail environment as well as wholesale markets. In practice, such issues are openly discussed and debated either as part of a utility's rate case or upon proposal of new or revision to existing utility tariffs.

For markets without active wholesale demand response, protection of nonparticipants falls to retail rate design. Very few states have established arrangements whereby ARCs can participate alongside retail regulated utilities and their established retail rates to ensure that nonparticipating retail customers are not harmed (Indiana appears to provide an example of one state).

Utilities typically set retail rates based on the estimated value of the customer's reduced demand to the utility (all customers). Presumably this value is a "net benefit" to all customers, including nonparticipants. Thus, nonparticipants are protected if ARCs receive this retail rate or a rate that does not increase the overall cost of the demand response program.

Utility Operations / Utility-Operated Demand Response Programs

- What is the definition of utility operations?
- Is this a relevant question if "utilities" in the RTOs in which ARCs operate are basically distribution companies [because the retail markets have been deregulated]?

---

[59] As of 2010, Indiana had 1,891 MW of demand response potential peak reduction as compared to Minnesota's 4,410 MW. "Assessment of Demand Response & Advanced Metering: Staff Report," Federal Energy Regulatory Commission, February 2011, p. 38. Customer demand in Indiana is close to double Minnesota demand.

[60] *See* "Moeller, Commissioner, dissenting" in "Demand Response Compensation in Organized Wholesale Markets," Federal Energy Regulatory Commission (Docket No. RM10-17-000), March 15, 2011, p. 4.

- Does a deregulated retail market facilitate ARC participation and reduce the potential impacts on utility operations?
- Do utilities in RTOs in which ARCs are active have significant utility-administered demand response programs?
- Can utility and ARC-administered demand response programs complement one another?
- Do utility and ARC-administered demand response programs compete?

This section combines discussion of ARC effects on utility operations and utility-administered demand response programs because these are inter-related issues as applied to utilities in the Northeastern RTOs.

What do we mean by Utility Operations?

"Utility operations" refers to the activities required to operate the utility. It is a broad term that encompasses daily activities (running power plants, managing regulatory relationships, marketing energy efficiency programs, dispatching demand response programs, running computer systems, etc.) and longer-term activities (forecasting and planning processes, finance and accounting activities, etc.). For purposes of this analysis, it can be distinguished from maintenance activities, which mainly focus on maintaining as opposed to operating the utility. The distinction is not clear-cut, but it limits the scope of items on which one might focus.

Utility operations as they relate to demand response and ARCs is an even narrower term. To the extent ARCs interact with utility operations in a similar manner to a utility's other demand response activities (and, therefore, aren't really a change in the way the utility operates), then the effect is considered limited. If ARCs require changes in the utility's operations, then such an effect is noteworthy and applicable to this study.

It is useful to further define the term "utility". In regulated states like Minnesota, utility generally refers to the vertically integrated entity that provides generation, distribution and transmission services. In deregulated states, laws require that utilities "unbundle" some of these services and act as common carriers for electricity with competitive providers responsible for providing retail electric service. Utilities acting as local distribution companies may provide default retail electric services for customers who do not choose a competitive provider. Laws and regulations may also impose energy efficiency and demand response requirements on the LDC. Although the operations of a local distribution company differ from those of a vertically integrated utility, this report assumes that "utility" in deregulated states refers to the LDC.

What do we mean by utility-operated demand response programs?

For purposes of this analysis, the term "utility-operated demand response programs" refers to demand response programs run by vertically integrated utilities or local distribution companies (LDCs).

What impacts do ARC operations have on utility operations and utility-operated demand response programs?

In conducting the research the authors sought input from utilities and ISOs/RTOs to assess whether ARC operations have an impact on utility operations or utility-operated demand response programs. Unfortunately, information from RTOs regarding utility-related operations was limited and it was difficult to obtain useful information from utilities, particularly those that were described as "active" demand response participants in RTO markets. The difficulty in obtaining information from these utilities may be an indication that utilities are reluctant to discuss issues that are considered proprietary and that they are, in fact, in competition with ARCs. The following information came from RTO representatives and those utilities that were willing to discuss these issues.

PJM Interconnection (PJM)

According to PJM staff, some utilities in the PJM area are very active with demand response, with some even marketing outside their service territories. Maryland has a large load control program and several municipalities and cooperatives are also actively participating in wholesale demand response activities. However, as noted, PJM does not distinguish between the different types of CSPs so PJM staff was not aware of effects on utility operations.

The PJM utilities with which the authors spoke claimed that ARC participation has had impacts on utility operations. Utilities are responsible for providing customer data that ARCs or CSPs need in order to register sites in PJM's demand response programs. This information includes customer account numbers, peak load contribution, capacity and energy loss factors, and confirmation regarding whether a customer has an interval meter.

Utilities usually have to approve site registrations and are responsible for providing a year's worth of customer data to the ARC/CSP for use in the baseline calculations. After load response events, utilities provide event data, so that the ARC/CSP can calculate the settlement amounts. In addition utilities review and approve settlements after demand response events and take orders for the installation of interval meters if requested by the ARC/CSP.

The utilities' ongoing efforts to provide meter data has been reduced by implementing automated systems; however, the utilities had to incur costs related to the design and build of such systems and must continue to maintain these systems.

Additionally, the utilities often had to reprioritize the smart/interval meter installation in response to requests from ARCs. Such processes do result in additional administrative burden, but additional meter costs would only be incurred if the utility did not plan to install an advanced meter for a particular customer.

The utilities further believe that large C&I customers are experienced and familiar with the available programs in the PJM market and that they readily "shop around" to get the best possible contract and payment terms; however, in some cases, there can be customer confusion since there are multiple programs offered by both ARCs and utilities.

New York Independent System Operator (NYISO)

According to NYISO staff, utilities in the NYISO control area do not have the resources to recruit customers and since the advent of deregulation, have focused on being "wires companies". In NYISO, utilities and end-use customers (direct bidding) still provide a portion of the demand response services, but these services amount to less than a third of the total resources provided. CSPs entered the market in 2000, and there are now multiple CSPs in the market. The

Public Service Commission supported NYISO's programs from the beginning since utilities did not have their own demand response programs.

One of the major utilities stated that the vast majority of their demand response resources are secured via aggregators who work independently. The utility sees the aggregators as an important partner in the market. They are also an important voice in the regulatory process and have contributed substantially to NYISO DR program design. According to the utility, aggregators with a strong focus on controls and automation seem more aligned with a market that is evolving towards automated dispatch. One specific challenge identified by the utility relates to locational dispatch. Aggregators operating in a free market do not necessarily acquire load control in the network locations where the utility needs demand response. The utility is trying to change this situation via incentives or bi-lateral agreements.

The utility has also created its own distribution-level demand response program to address local reliability issues. This program is subordinate to NYISO's programs, but it also affords the utility greater flexibility in managing local loads. However, ARCs (who can recruit for the utility's programs) prefer to enroll customers in NYISO's programs, mainly because of preferable contract terms and payment conditions. Such preferences can create barriers to enrollment of resources in the utility's demand response programs.

ISO-New England (ISO-NE)

ISO-NE staff revealed that most of their demand response is also provided by non-utility ARCs/CSPs, due mainly to the fact that the bulk of ISO-NE is deregulated (~94 percent, only Vermont not). Utilities are mostly involved in energy efficiency programs but, in some states, are also encouraged to provide DR. Some utilities have their own energy programs, which are not reported to the ISO because the utilities use the resources for local reliability purposes.

The authors were able to interview one of the larger utilities in the ISO-NE area. The utility currently does not have any DR programs and has no relationships with aggregators but plans to file for a DR pilot program. Because this utility doesn't consider DR as part of its business model, the utility expects to allow ARCs to fully participate in future DR programs. The utility does have some concern that aggregator participation will cause problems on the distribution side. For example, the utility does not want its customers to have two meters installed and doesn't want to deal with customer complaints resulting from bill adjustments that the ARC/CSP may make for load reduction events.

Connecticut utilities are actively involved in ISO-NE demand response activities. According to ISO-NE, one of the state's utilities is one of the bigger demand response providers in the region. As with other deregulated utilities, though, United Illuminating has made the necessary investments and process changes to facilitate competitive provider provision of retail electric service to its customers. [61]

---

[61] UI's elaborate Supplier Management System dedicated to electric suppliers/aggregators attest to this statement. http://www.sms.uinet.com/wps/portal/

Changes required to accommodate ARCs

It is unclear what changes would be required for Minnesota utilities to accommodate ARC participation, although costs to enable ARCs to directly engage customers and interface with the utility could be non-trivial. The benefits, on the other hand, are less clear. The Brattle Group's *Fostering Economic Demand Response in the Midwest ISO* makes this very clear in qualifying its recommendation that MISO facilitate entry of CSPs,

> However, this recommendation is made subject to several caveats. First, the degree to which CSPs could disrupt LSE planning and trading needs to be considered. Second, the relative costs of accommodating CSPs compared with the benefits to the market must be further examined. The costs include charges to other customers, LSEs and market participants to fund payments for "negawatts" (including phony negawatts if the customer baseline load (CBL) does not accurately measure what an end-user would have consumed but for its response to price signals), increased operational costs of incorporating resources that are not fully controllable, predictable, or nodally dispatched, and administrative costs. Administrative costs include the costs of administering programs and modifying the Midwest ISO's tariff, business practices, market software, and settlement systems. (Minor modifications might be needed to allow CSPs to offer demand reductions at the same commercial pricing node as the host LSE; it will also be necessary to implement CBL and settlement mechanisms in the software. Third, payments to CSPs should avoid the issue of "double dipping," as discussed above. Determining the appropriate retail rate offset is not necessarily a straightforward matter for those end-use customers whose retail rates are not transparent to the Midwest ISO.[62]

Since the 2008 study was completed, MISO has indeed modified its tariffs to allow ARC participation (subject to FERC approval), has begun to implement required system changes, and has established mechanisms that it hopes will address the other issues Brattle raises. This study, though, focused on MISO rather than the changes that might be required at the state level and within utilities.

Difficult to assess impacts on utility operations and utility-administered demand response program in the Northeast

In conclusion it is difficult to draw conclusions about the effects of ARCs on utility operations and utility-administered demand response programs by examining Northeast RTOs because the circumstances with Northeast RTOs are very different from those in the Midwest ISO. In addition, information from utilities whose programs were likely most impacted was unavailable. Retail electricity deregulation, though, has created a different environment for aggregators (and competitive retail electric providers) and utilities have already made large-scale investments and process changes to accommodate competitive retail electric service. Further changes to accommodate ARCs are likely not substantial.

[62] "Fostering Economic Demand Response in the Midwest," p. 74.

Section 4: Recommended Next Steps

Primary data studies

This study has revealed the fact that limited information exists regarding the effects of ARCs on prices, reliability, nonparticipating customers, utility operations, and utility-administered demand response programs. It has also shown that conducting such analyses would also be quite difficult because performance data that segregate ARCs from non-ARCs is also not readily available. It may be possible to enter into confidential agreements with ARCs, RTOs and other relevant participants to be able to conduct such analyses, but such arrangements might be difficult to secure and would not necessarily yield sufficient data to draw definitive conclusions.[63]

Most importantly, the MISO's demand response activities remain in their infancy, particularly as they relate to ARCs. In the coming years, this situation will likely change because ARCs will likely begin to play more active roles in MISO markets. At that time, it might make sense to revisit the questions and determine what additional data may be available from MISO.

Another possible future study would be one that contrasts the impact of demand response between RTOs with large amounts of ARC participation and those with limited ARC participation. Unfortunately, RTOs with limited amounts of ARC participation are few because RTOs outside of the Northeast and Texas have only recently begun to actively develop and promote their demand response activities. These other RTOs include the MISO, the Southwestern Power Pool, and the California ISO. After ARCs have entered these markets, it might make sense to revisit the questions and determine what additional data may be available from other RTOs.

Pilots

The Minnesota Public Utilities Commission in its February 8, 2011 Order in Docket No. E-999/CI-09-1449 requested that utilities submit by September 1, 2011 comments "on the ability to expand demand response options through contracts with third parties in order to achieve demand response potential."[64] This approach could be one way to assess whether Minnesota ratepayers could benefit from participation by ARCs but it would help to put in place mechanisms to test the effects such tariff changes would have on the issues the PUC raises. Another way to test these issues was suggested in the PUC's May 18, 2010 Order in the same docket. In that order,

[63] The team lead for FERC's Assessment of Demand Response & Advanced Metering indicated in conversations that their data as it relates to ARCs is limited because ARCs consider much of their data proprietary and confidential. FERC's surveys for the Assessment are voluntary. Email exchange with Dean Wight, Team Lead, Federal Energy Regulatory Commission Team, August 5, 2011.

[64] "Order Requiring Further Filings by Utilities," Minnesota Public Utilities Commission (Docket No. E-999/CI-09-1449), February 8, 2011, p. 5.

the PUC also encouraged utilities to submit pilot projects designed to "explore the potential for ARCs and other third-party providers to increase levels of demand response in Minnesota".[65]

Establishing such a pilot could address the PUC's questions by setting-up an "experiment" to test the effects of ARC participation on prices, reliability, nonparticipating customers, utility operations, and utility-administered demand response programs while meeting the PUC's other requirements.[66]

The pilot could be designed to target a specific class of customers and allow participation by multiple ARCs, with program parameters consistent with one of the MISO's demand response opportunities: Emergency Demand Response, DRR-Type 1, DRR-Type 2, etc. It would be best to focus on only one of the programs to improve data collection and ensure the ability to conform to the PUC's order points.

One model for such a pilot is the California ISO's Proxy Demand Resource proposal, which FERC conditionally approved on July 15, 2010. [67] The program compensates market participants for responding to price signals by reducing retail customers' electricity use. Demand Response Providers are allowed to participate in in the CAISO's day-ahead and real-time energy markets and certain ancillary services markets.

California's Proxy Demand Resource (PDR) mechanism could provide a good analog for Minnesota's situation because most California utility customers receive bundled loads from their utility (not deregulated).[68] The California ISO has implemented the program but there has not yet been any non-utility participation as of this writing. Due to the regulatory construct in California, there have been delays in allowing bundled customers to participate directly in the market through an ARC or otherwise outside of a utility program.

All three California utilities conducted pilots (Participating Load Pilot) to test customer participation in a utility-initiated demand resource program directly bid into the CAISO wholesale market prior to the implementation of PDR. Only one utility, SDG&E, used aggregators. This pilot allowed ARCs to participate and then tested a variety of issues. [69] It has

---

[65] "Order Prohibiting Bidding of Demand Response into Organized Markets by Aggregators of Retail Customers and Requiring Further Filings by Utilities," Minnesota Public Utilities Commission (Docket No. E-999/CI-09-1449), May 18, 2010, p. 7.

[66] "Order Prohibiting Bidding of Demand Response into Organized Markets by Aggregators of Retail Customers and Requiring Further Filings by Utilities," Minnesota Public Utilities Commission, pp. 7-8.

[67] "Order Conditionally Accepting Tariff Changes and Directing Compliance Filing," Federal Energy Regulatory Commission (Docket No. ER10-765-001), July 15, 2010.

[68] As a legacy of California's deregulation experience, there remain a limited number of direct access and community choice aggregation customers.

[69] "San Diego Gas & Electric Participating Load Pilot: 2009 Evaluation," San Diego Gas & Electric Company, February 1, 2010.

since given rise to another pilot, the Demand Response Wholesale Market Pilot, which uses the Proxy Demand Resource mechanism now that it has been implemented by the CAISO.[70]

Wisconsin Public Service (WPS) also provides a good example of a utility that has sought to implement programs that take advantage of MISO markets. WPS modified its legacy interruptible program to allow bidding in price responsive demand in the Midwest ISO day-ahead market. The Company's CP-I2 rate targets commercial and industrial customers with interruptible demand of 200 kW or more with customers subject to emergency and economic interruptions for a maximum of 300 hours per year for legacy DR, and 600 hours per year for new interruptible DR. Emergency interruptions are declared during system reliability events, while economic interruptions are declared when the wholesale market prices significantly exceed an established Economic Interruption Trigger Price (EITP). Customers have a "buy-through" option to specify a quantity and price at which they are willing to buy energy day-ahead instead of paying the real-time prices.[71]

[70] "San Diego Gas & Electric Report on Demand Response Integration into CAISO Wholesale Markets," San Diego Gas & Electric Company, January 31, 2011.

[71] "Fostering Economic Demand Response in the Midwest ISO," p. 6.

Conclusion

Overall conclusion regarding ARC impacts

The analysis was not able to state definitively what impact ARCs have had on prices, reliability, nonparticipating customers, utility operations, or utility-operated demand response programs. To the extent demand response has had effects on capacity prices, reliability and nonparticipating customers, one can reasonably argue that aggregators of retail customers are a primary driver of those effects in the PJM Interconnection, ISO New England, and New York ISO. This is a reasonable argument because ARCs constitute the bulk of the demand response resources (particularly the new resources) in these three RTOs. It is not clear that ARCs are necessarily large participants in day-ahead energy markets and so, based on data from ISO-NE and NYISO, it is more difficult to connect ARCs with effects on energy prices.

Such statements and arguments do not apply to the Midwest Independent Transmission System Operator because ARCs are not active participants in MISO demand response activities. In contrast with the Northeastern RTOs, MISO already has a substantial amount of demand response participation through legacy and new utility demand response programs.

Because most of the regions within MISO are still served by regulated utilities, MISO is very different from the Northeast RTOs and ERCOT and, therefore, issues such as demand response may need to be treated differently. ARCs may very well have effects on the issues raised by the Minnesota Public Utilities Commission and, at least with respect to those that can be used to objectively determine whether ARC participation should be encouraged (prices, reliability, nonparticipants), such effects may be positive (lower prices, improved reliability, no or positive effects on nonparticipants). Given the role that utilities will play in Minnesota's regulatory scheme and the presence of substantial demand response resources, Minnesota may be best served by moving towards a market structure that continues to maximize cost effective demand response participation. ARCs may be an important part of such a market, but their impact on Minnesota utility ratepayers should be further evaluated and tested.

Bibliography

Association for Demand Response and Smart Grid (ADS). "Demand Response & Smart Grid—State Legislative and Regulatory Policy Action Review: May 2010 – June 2011." June 2011.

Cappers, P. Goldman, C. Kathan, D. "Demand response in U.S. electricity markets: Empirical Evidence." *Energy* 35 (2010). July 12, 2009.

Chaterjee, B. and Dorman, E. (California Public Utilities Energy Division Staff). "CPUC Comments: Demand Response Net Benefits Testing Issue Paper." June 20, 2011.

Demand Response Working Group, Midwest ISO. "Demand Participation Update," April 4, 2011.

EnerNOC. "Demand Response for Utilities in Restructured Markets: Getting More from Existing Assets." *White Paper*. 2009.

Eto, J. (Environmental Energy Technologies Division Ernest Orlando Lawrence Berkeley National Laboratory). "The Past, Present, and Future of U.S. Utility Demand-Side Management Programs." December 1996.

Federal Energy Regulatory Commission Staff. "Assessment of Demand Response & Advanced Metering: Staff Report." February 2011.

Federal Energy Regulatory Commission. "Order Conditionally Accepting Tariff Changes and Directing Compliance Filing." *Docket No. ER10-765-001,* July 15, 2010.

Federal Energy Regulatory Commission. "Demand Response Compensation in Organized Wholesale Energy Markets." *Docket No. RM10-17-000, Order No. 745*, March 15, 2011.

Federal Energy Regulatory Commission. "Final Rule. Wholesale Competition in Regions with Organized Electric Markets." *Docket Nos. RM07-19-000 and AD07-7-000.* October 17, 2008.

Global Energy Partners, LLC. "Assessment of Demand Response and Energy Efficiency Potential for MISO." *Report #1314,* November 2010.

Goldman, C. Reid, M. Levy, R., and Silverstein, A. "Coordination of Energy Efficiency and Demand Response." For National Action Plan for Energy Efficiency. January 2010. <*www.epa.gov/eeactionplan*>

Goldman, C., Bharvirkar, R., Heffner, G., and Berkeley, L. (Lawrence Berkeley National Laboratory). "Midwest Retail Demand Response Program Survey Results." Midwest Demand Response Initiative (MWDRI). March 7, 2008.

Hempling, S. "Demand Response and Aggregators of Retail Customers: Legal, Economic, and Jurisdictional Issues." Materials for National Regulatory Research Institute Teleseminar *Demand Response, Retail Aggregators, FERC, and the States: Conflict or Cooperation?* December 15, 2010.

Indiana Utility Regulatory Commission (IURC). "Standard Energy Contract Rider No. 22: Duke Energy Market Based Demand Response (MBDR) Rider Applicable to HLF and LLF Rate Groups (Cause No. 43566)." Approved March 2, 2011.

ISO New England. "Semi-Annual Status Report on Load Response Programs of ISO New England. Inc." *Docket No. ER03-345-*, June 30, 2011.

ISO New England. "Wholesale Electricity Markets." August 7, 2011. <http://www.iso-ne.com/img/wem.pdf>

McAnany, J. "Load Response Activity Report: July 2011." PJM Interconnection, LLC. July 11, 2011.

Midwest Independent Transmission System Operator. "Midwest Independent Transmission System Operator, Inc. Filing to Enhance RAR By Incorporating Locational Capacity Market Mechanisms", *FERC Docket Nos. ER08-394-004; ER08-394-005; ER08-394-021; ER08-394-022; ER08-394-028; ER08-394-029; and ER11- ___ -000.* July 20, 2011.

Minnesota Public Utilities Commission. "Order Requiring Further Filings by Utilities." *Docket No. E-999/CI-09-1449.* February 8, 2011.

Minnesota Public Utilities Commission. "In the Matter of an Investigation of Whether the Commission Should Take Action on Demand Response Bid Directly into MISO Markets by Aggregators of Retail Customers Under FERC Orders 719 and 719-A." *Docket No. E-999/CI-09-1449.* May 10, 2010.

Minnesota Public Utilities Commission. "Order Prohibiting Bidding of Demand Response into Organized Markets by Aggregators of Retail Customers and Requiring Further Filings by Utilities." *Docket No. E-999/CI-09-1449.* May 18, 2010.

Morenoff, D. Wellinghoff, Hon. J. "Recognizing the Importance of Demand Response: The Second Half of the Wholesale Electric Market Equation." *Energy Law Journal* (Volume 28, No. 2). 2007.

New York Independent System Operator. "Annual Report." *Federal Energy Regulatory Commission Docket No. ER01-3001-000.* January 18, 2011.

New York Independent System Operator. "Compliance Filing in Docket Nos. ER01-3001-, ER03-647-." *Federal Energy Regulatory Commission Docket No. ER01-3001-000.* January 15, 2009.

Newell, S. and Hajos, A. (The Brattle Group). "Demand Response in the MISO: An Evaluation of Wholesale Market Design." January 29, 2010.

Newell, S. Bhattacharyya, A. Madjarov, K. (The Brattle Group). "Cost-Benefit Analysis of Replacing the NYISO's Existing ICAP Market with a Forward Capacity Market." Prepared for the New York Independent System Operator. June 15, 2009.

Organization of MISO States. "Demand Response Compensation in Organized Wholesale Energy Markets." Federal Energy Regulatory Commission, *Docket No. RM10-17-000,* April 14, 2011.

PJM Interconnection, LLC. "RPM Offers by Commitment and Fuel Type." May 25, 2011. Accessed on August 8, 2011. *<http://www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx>*

Reeder, M. Bresler, F. Feit, J. Newell, S. Schisler, K. (presenters) "Demand Response Gets Market Prices: Now What?" *National Regulatory Research Institute (NRRI) Teleseminar.* June 9, 2011.

San Diego Gas & Electric Company. "San Diego Gas & Electric Participating Load Pilot: 2009 Evaluation." February 1, 2010.

San Diego Gas & Electric Company. "San Diego Gas & Electric Report on Demand Response Integration into CAISO Wholesale Market." January 31, 2011.

Synapse Energy Economics. "Avoided Energy Supply Costs in New England: 2011 Report." Prepared for the Avoided-Energy-Supply-Component Study Group. July 21, 2011.

The Brattle Group. "Fostering Economic Demand Response in the Midwest ISO." Prepared for the Midwest Independent Transmission System Operator. December 30, 2008.

The Brattle Group. "Quantifying Demand Response Benefits In PJM." Prepared for PJM Interconnection, LLC and the Mid-Atlantic Distributed Resources Initiative (MADRI). January 29, 2007.

U.S. Department of Energy. "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them." *A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005.* February 2006.

Wellinghoff, Hon. J., Morenoff, D. L., Pederson, J., Tighe, M. E. (Federal Energy Regulatory Commission). "Creating Regulatory Structures for Robust Demand Response Participation in Organized Wholesale Electric Markets." In *2008 ACEEE Summer Study Proceedings.* August 17, 2008.

Appendix A - Reports on the Benefits of Demand Response to Electricity Markets

"Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the United States Congress Pursuant to Section 1252 of the Energy Policy Act of 2005," United States Department of Energy, Feb. 2006;

"Consumers Could Benefit from Demand Response Programs, but Challenges Remain," United Government Accountability Office, GAO-04-844 Electricity Markets, Aug. 13, 2004;

"Demand Response for Power System Reliability: FAQ," Prepared by Brendan Kirby for Office of Electricity Delivery and Energy Reliability Transmission Reliability Program, U.S. Department of Energy, December 2006.

"Demand Response in the Midwest ISO: An Evaluation of Wholesale Market Design," Prepared for the Midwest Independent System Operator by The Brattle Group, January 2010;

"Demand response in U.S. electricity markets: Empirical evidence," Peter Cappers, Charles Goldman, David Kathan, Ernest Orlando Lawrence Berkeley National Laboratory, June 2009.

"Fostering Economic Demand Response in the Midwest ISO," Prepared for the Midwest Independent Transmission System Operator by The Brattle Group, December 30, 2008;

"Loads Providing Ancillary Services: Review of International Experience: Review of International Experience," Grayson Heffner, Charles Goldman, Brendan Kirby, and Michael Kintner-Meyer, Ernest Orlando Lawrence Berkeley National Laboratory, May 2007.

"Quantifying Demand Response Benefits In PJM", Prepared for the Mid-Atlantic Distributed Resources Initiative (MADRI) by The Brattle Group, Jan. 29, 2007;

"Social Welfare Implications of Demand Response Programs in Competitive Markets," Prepared by Neenan Associates for Ernest Orlando Lawrence Berkeley National Laboratory, August 2003;

"Wholesale Competition in Regions with Organized Electric Markets," Final Rule (Docket Nos. Docket Nos. RM07-19-000 and AD07-7-000), Federal Energy Regulatory Commission, October 17, 2008.

Appendix B – ARC Status in States

Updated August 1, 2011

STATE	DOCKET #	STATUS AT COMMISSION
Illinois		No opt out – allows aggregators
Indiana	43566	7/28/10 - Order prohibits end-use customers from directly participating in RTO DR programs w/o prior PSC approval – allows participation through LSE approved tariffs.[72]
Iowa	NOI-2008-0003	3/29/10 – Order prohibiting ARCs
Michigan	U-16020	12/10/10 - Temporary ban with clarification on 2/22/11 stating that ban doesn't apply to 2 existing PJM customers for term of current contracts.
Minnesota	CI-09-1449	5/18/10 - Order prohibits ARC participation but requires filings from utilities. Latest filings are due 9/1/11.
Missouri	2010-187	3/31/10 - Order temporarily prohibiting; have held multiple workshops and have begun to develop draft rules to, among other things, potentially allow ARCs to participate in MO.
North Dakota	PU-10-59	8/24/10 – Order prohibits ARCs unless rate schedule under which customer receives service allows sales for resale.
Ohio		No opt out – allows aggregators
South Dakota	EL10-0003	5/25/10 – Prohibit ARC participation in market until further notice.
Wisconsin	5-UI-116	10/15/09 – Order temporarily prohibiting ARCs

Table based on information provided by Midwest Independent System Operator.

[72] "The Commission instead ordered NIPSCO and the other Indiana jurisdictional electric utilities (collectively the "Respondent Utilities") to file with the Commission for approval tariffs or riders authorizing the participation of their respective retail customers in RTO demand response programs through the Respondent Utilities. The Commission initiated two subdockets, one for MISO utilities and one for PJM utilities, to consider development of these tariffs." Case No. 43566, March 2, 2011, p. 2.

Appendix C – 2010 RTO Demand Response Programs[73]

ISO/RTO Product / Service						*Product / Service Features*							
Region	Acronym	Name	Service Type	Begin Date	End Date	Minimum Eligible Resource Size	Minimum Reduction Amount	Aggregation Allowed	Participa-tion	Response Required	Primary Driver	Deployment "Overuse" Restriction	"Peak" Hours Only
ISO-NE													
ISO-NE	**RTDRP**	Real Time Demand Response Program [Capacity Component]	Capacity	Active	5/31/10	100 kW	100 kW	Yes	Voluntary	Mandatory	Reliability	None	No
ISO-NE	**RTDRP**	Real Time Demand Response Program [Energy Component]	Energy	Active	5/31/10	100 kW	100 kW	Yes	Voluntary	Mandatory	Economic	None	No
ISO-NE	**DALRP / RTDR**	Day-Ahead Load Response Program for RTDRP	Energy	Active	None	100 kW	100 kW	Yes	Voluntary	Mandatory	Economic	None	Yes
ISO-NE	**DALRP / RTPR**	Day-Ahead Load Response Program for RTPR	Energy	Active	None	100 kW	100 kW	Yes	Voluntary	Mandatory	Economic	None	Yes
ISO-NE	**DRR**	Demand Response Reserves Pilot	Reserve	Active	5/31/10	100 kW	100 kW	Yes	Voluntary	Mandatory	Reliability	None	No
ISO-NE	**RTPR**	Real Time Price Response Program	Energy	Active	None	100 kW	100 kW	Yes	Voluntary	Voluntary	Economic	None	Yes
ISO-NE	**RTDR**	Real Time Demand Response Resource	Capacity	Quals Active, Delivery starting 2010-06-01	None	100 kW	1 kW	Yes	Voluntary	Mandatory	Reliability	None	No
ISO-NE	**OP**	FCM: On-Peak Demand Resources	Capacity	Quals Active, Delivery starting 2010-06-01	None	100 kW	1 kW	Yes	Voluntary	Mandatory	Reliability	None	Yes
ISO-NE	**SP**	FCM: Seasonal Peak Demand Resources	Capacity	Quals Active, Delivery starting 2010-06-01	None	100 kW	1 kW	Yes	Voluntary	Mandatory	Reliability	None	Yes
ISO-NE	**RTEG**	Real Time Emergency Generation Resource	Capacity	Quals Active, Delivery starting 2010-06-01	None	100 kW	1 kW	Yes	Voluntary	Mandatory	Reliability	None	No
ISO-NE	**DARD**	Dispatchable Asset Related Demand	Reserve	Active	None	1 MW	1 kW	Yes	Voluntary	Mandatory	Economic	None	No

[73] Midwest ISO doesn't have "programs" per se. MISO facilitates demand response participation in existing markets but does not sponsor programs.

ISO/RTO Product / Service						*Product / Service Features*							
Region	Acronym	Name	Service Type	Begin Date	End Date	Minimum Eligible Resource Size	Minimum Reduction Amount	Aggregation Allowed	Participa-tion	Response Required	Primary Driver	Deployment "Overuse" Restriction	"Peak" Hours Only
MISO													
MISO	DRR-I	Demand Response Resource Type I (Energy)	Energy	Active	2010-05-31 (Pending FERC Approval)	1 MW		Yes	Voluntary	Voluntary	Economic	Biddable Daily Participation	No
MISO	DRR-I	Demand Response Resource Type I (Energy)	Energy	2010-06-01 (pending FERC approval)	None	1 MW		Yes	Voluntary	Voluntary	Economic	Biddable Daily Participation	No
MISO	DRR-I	Demand Response Resource Type-I (Reserve)	Reserve	Active	2010-05-31 (Pending FERC Approval)	1 MW		Yes	Voluntary	Mandatory	Economic	Biddable Daily Participation	No
MISO	DRR-I	Demand Response Resource Type-I (Reserve)	Reserve	2010-06-01 (pending FERC approval)	None	1 MW		Yes	Voluntary	Mandatory	Economic	Biddable Daily Participation	No
MISO	DRR-II	Demand Response Resource Type II (Energy)	Energy	Active	2010-05-31 (Pending FERC Approval)	1 MW		No	Voluntary	Voluntary	Economic	Biddable Daily Participation	No
MISO	DRR-II	Demand Response Resource Type II (Energy)	Energy	2010-06-01 (pending FERC approval)	None	1 MW		No	Voluntary	Voluntary	Economic	Biddable Daily Participation	No
MISO	DRR-II	Demand Response Resource Type-II (Reserve)	Reserve	Active	2010-05-31 (Pending FERC Approval)	1 MW		No	Voluntary	Mandatory	Economic	Biddable Daily Participation	No
MISO	DRR-II	Demand Response Resource Type-II (Reserve)	Reserve	2010-06-01 (pending FERC approval)	None	1 MW		No	Voluntary	Mandatory	Economic	Biddable Daily Participation	No
MISO	DRR-II	Demand Response Resource Type-II (Regulation)	Regulation	Active	None	1 MW		No	Voluntary	Mandatory	Economic	Biddable Daily Participation	No
MISO	EDR	Emergency Demand Response	Energy	Active	None	100 kW		Yes	Voluntary	Voluntary	Reliability	Biddable Daily Participation	No
MISO	LMR	Load Modifying Resource	Capacity	Active	None	100 kW		Yes	Voluntary	Mandatory	Reliability	Minimum use 5x	No

ISO/RTO Product / Service						Product / Service Features							
Region	Acronym	Name	Service Type	Begin Date	End Date	Minimum Eligible Resource Size	Minimum Reduction Amount	Aggregation Allowed	Participa-tion	Response Required	Primary Driver	Deployment "Overuse" Restriction	"Peak" Hours Only
NYISO													
NYISO	DADRP	Day-Ahead Demand Response Program	Energy	Active	None	1 MW	1 MW	Yes	Voluntary	Mandatory	Economic	None	No
NYISO	DSASP	Demand Side Ancillary Services Program	Reserve	Active	None	1 MW	1 MW	No	Voluntary	Mandatory	Economic	None	No
NYISO	DSASP	Demand Side Ancillary Services Program	Reserve	Active	None	1 MW	1 MW	No	Voluntary	Mandatory	Economic	None	No
NYISO	DSASP	Demand Side Ancillary Services Program	Regulation	Active	None	1 MW	1 MW	No	Voluntary	Mandatory	Economic	None	No
NYISO	EDRP	Emergency Demand Response Program	Energy	Active	None	100 kW (per Zone)	100 kW (per Zone)	Yes	Voluntary	Voluntary	Reliability	None	No
NYISO	SCR	Installed Capacity Special Case Resources (Energy Component)	Energy	Active	None	100 kW (per Zone)	100 kW (per Zone)	Yes	Voluntary	Mandatory	Reliability	None	No
NYISO	SCR	Installed Capacity Special Case Resources (Capacity Component)	Capacity	Active	None	100 kW (per Zone)	100 kW (per Zone)	Yes	Voluntary	Mandatory	Reliability	None	No

ISO/RTO Product / Service						Product / Service Features							
Region	Acronym	Name	Service Type	Begin Date	End Date	Minimum Eligible Resource Size	Minimum Reduction Amount	Aggregation Allowed	Participa-tion	Response Required	Primary Driver	Deployment "Overuse" Restriction	"Peak" Hours Only
PJM													
PJM	-	Economic Load Response (Energy)	Energy	Active	None	100 kW	100 kW	Yes	Voluntary	Voluntary	Economic	Biddable Daily Participation	No
PJM	-	Economic Load Response (Synchronized reserves)	Reserve	Active	None	500 kW	500 kW	Yes	Voluntary	Mandatory	Reliability	Biddable Hourly Participation	No
PJM	-	Economic Load Response (Day ahead scheduling reserve)	Reserve	Active	None	500 kW	500 kW	Yes	Voluntary	Mandatory	Reliability	Biddable Hourly Participation	No
PJM	-	Economic Load Response (Regulation)	Regulation	Active	None	500 kW	500 kW	Yes	Voluntary	Mandatory	Reliability	Biddable Hourly Participation	No
PJM	-	Emergency Load Response - Energy Only	Energy	Active	None	100 kW	100 kW	Yes	Voluntary	Voluntary	Economic	None	No
PJM	-	Full Emergency Load Response (Capacity Component)	Capacity	Active	None	100 kW	100 kW	Yes	Voluntary	Mandatory	Reliability	10 days up to 6 hours per day	Yes
PJM	-	Full Emergency Load Response (Energy Component)	Energy	Active	None	100 kW	100 kW	Yes	Voluntary	Mandatory	Reliability	10 days up to 6 hours per day	Yes

Source: "North American Wholesale Electricity Demand Response 2010 Comparison," ISO/RTO Council, May 17, 2010.

Demand Response Programs

Classification	Definition[1]	IPL Offer Today	IPL Potential Peak Load Reduction (MW) current	proposed	total	IPL Plans to Offer in 2012 and Beyond
INCENTIVE-BASED						
Demand Bidding and Buyback	A program which allows a demand resource in retail and wholesale markets to offer load reductions at a price, or to identify how much load it is willing to curtail at a specific price.	No	Included in Interruptible Load			Monitor—not an available option at this time. IPL has proposed an alternative buy-through option as part of its proposed interruptible load tariff.
Direct Load Control (DLC)	A demand response activity by which the program sponsor remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers. Also known as direct control load management.	No	0	3.2	3.2	Addition—IPL will request Commission approval to offer a DLC program in its 2013-2015 Conservation Improvement Program (CIP).
Emergency Demand Response	A demand response program that provides incentive payments to customers for load reductions achieved during an Emergency Demand Response Event.	Yes	Included in Interruptible Load			Existing and Proposed—under IPL's existing interruptible/curtailable tariff, IPL may request an event when required for reliability.
Interruptible Load	Electric consumption subject to curtailment or interruption under tariffs or contracts that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. In some instance, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.	Yes	0.9	1.0	1.9	Proposed—under IPL's proposed interruptible/curtailable tariff, IPL may request an event when IPL anticipates peak load conditions.
Load as a Capacity Resource	Demand-side resources that commit to make pre-specified load reductions (peak load) when system contingencies arise.	Yes	Included in Interruptible Load			Proposed—under IPL's proposed interruptible/curtailable tariff, IPL may request an event when IPL anticipates peak load conditions.
Non-Spinning Reserves	Demand-side resource that may not be immediately available, but may provide solutions for energy supply and demand imbalance after a delay of ten minutes or more.	No	0	0	0	Monitor— lower value (prices) than energy DR and unique or specialized resource makes this a low priority.

[1] *2010 Assessment of Demand Response and Advanced Metering*, Appendix C: Survey Glossary, Federal Energy Regulatory Commission, pages 56-62, February 2011.

Demand Response Programs

Classification	Definition[1]	IPL Offer Today	IPL Potential Peak Load Reduction (MW)			IPL Plans to Offer in 2012 and Beyond
			current	proposed	total	
INCENTIVE-BASED						
Spinning Reserves	Demand-side resource that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an Emergency Event.	No	0	0	0	Monitor—lower value (prices) than energy demand response and unique or specialized resource makes this a low priority.
Regulation Service	A type of Demand Response service in which a Demand Response increase and decreases load in response to real-time signals from the system operator. Demand Resources providing Regulation Service are subject to dispatch continuously during a commitment period. This service is usually responsive to Automatic Generation Control (AGC) to provide normal regulating margin. Also known as regulation or regulating services, up-regulation and down-regulation.	No	0	0	0	Monitor— lower value (prices) than energy demand response and unique or specialized resource makes this a low priority.
TIME-BASED						
Critical Peak Pricing	Rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate or price for a limited number of days or hours.	No	0	0	0	Monitor—requires advanced metering technology.
Critical Peak Pricing with Load Control	Demand-side management that combines direct load control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.	No	0	0	0	Monitor—requires advanced technology to control customers' appliances.
Peak Time Rebate	Peak time rebates allow customers to earn a rebate by reducing energy use from a baseline during a specified number of hours on critical peak days. Like Critical Peak Pricing, the number of critical peak days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices.	No	0	0	0	Monitor—requires advanced metering technology

[1] *2010 Assessment of Demand Response and Advanced Metering*, Appendix C: Survey Glossary, Federal Energy Regulatory Commission, pages 56-62, February 2011.

Demand Response Programs

Classification	Definition[1]	IPL Offer Today	IPL Potential Peak Load Reduction (MW)			IPL Plans to Offer in 2012 and Beyond
			current	proposed	total	
INCENTIVE-BASED						
Real-Time Pricing	Rate and price structure in which the retail price for electricity typically fluctuates hourly or more often, to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.	No	0	0	0	Monitor Iowa Day-Ahead Hourly Pricing Program.
System Peak Response Transmission Tariff	The terms, conditions, and rates and/or prices for customers with interval meters who reduce load during peaks as a way of reducing transmission charges.	No	0	0	0	Not applicable—IPL does not own transmission assets.
Time-of-Use Pricing	A rate where usage unit prices vary by time period, and where the time periods are typically longer than one hour within a 24-hour day. Time-of-use rates reflect the average cost of generating and delivering power during those time periods.	Yes	<0.5	0.5	1	Enhance—In IPL Electric Rate Case (docket no. E001-GR-10-276), IPL filed revised time-of-use tariffs for residential, commercial, industrial and institutional customers. The proposed energy charges and peak periods have been adjusted to encourage participation.
Total IPL 2012 Demand Response Potential Peak Load Reduction (MW)			1.4	4.7	**6.1**	

Table Summary: IPL's current demand response programs total 1.4 MW of potential peak load reduction. IPL is proposing enhancements to two existing demand response programs and the addition of one new demand response program that will total an additional 4.7 MW of potential peak load reduction. Altogether, IPL plans to offer in 2012 and beyond demand response programs that will potentially reduce IPL's system peak load by approximately 6.1 MW. Based on IPL's 2010 summer system peak of 151.8 MW, this represents a four percent demand savings of IPL's system peak.

[1] *2010 Assessment of Demand Response and Advanced Metering*, Appendix C: Survey Glossary, Federal Energy Regulatory Commission, pages 56-62, February 2011.

Demand Response Programs

Classification	Definition[1]	IPL Offer Today	IPL Potential Peak Load Reduction (MW)			IPL Plans to Offer in 2012 and Beyond
			current	proposed	total	
INCENTIVE-BASED						
Demand Bidding and Buyback	A program which allows a demand resource in retail and wholesale markets to offer load reductions at a price, or to identify how much load it is willing to curtail at a specific price.	No	Included in Interruptible Load			Monitor—not an available option at this time. IPL has proposed an alternative buy-through option as part of its proposed interruptible load tariff.
Direct Load Control (DLC)	A demand response activity by which the program sponsor remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, water heater) on short notice. Direct load control programs are primarily offered to residential or small commercial customers. Also known as direct control load management.	No	0	3.2	3.2	Addition—IPL will request Commission approval to offer a DLC program in its 2013-2015 Conservation Improvement Program (CIP).
Emergency Demand Response	A demand response program that provides incentive payments to customers for load reductions achieved during an Emergency Demand Response Event.	Yes	Included in Interruptible Load			Existing and Proposed—under IPL's existing interruptible/curtailable tariff, IPL may request an event when required for reliability.
Interruptible Load	Electric consumption subject to curtailment or interruption under tariffs or contracts that provide a rate discount or bill credit for agreeing to reduce load during system contingencies. In some instance, the demand reduction may be effected by action of the System Operator (remote tripping) after notice to the customer in accordance with contractual provisions.	Yes	0.9	1.0	1.9	Proposed—under IPL's proposed interruptible/curtailable tariff, IPL may request an event when IPL anticipates peak load conditions.
Load as a Capacity Resource	Demand-side resources that commit to make pre-specified load reductions (peak load) when system contingencies arise.	Yes	Included in Interruptible Load			Proposed—under IPL's proposed interruptible/curtailable tariff, IPL may request an event when IPL anticipates peak load conditions.
Non-Spinning Reserves	Demand-side resource that may not be immediately available, but may provide solutions for energy supply and demand imbalance after a delay of ten minutes or more.	No	0	0	0	Monitor— lower value (prices) than energy DR and unique or specialized resource makes this a low priority.

[1] *2010 Assessment of Demand Response and Advanced Metering*, Appendix C: Survey Glossary, Federal Energy Regulatory Commission, pages 56-62, February 2011.

Demand Response Programs

Classification	Definition[1]	IPL Offer Today	IPL Potential Peak Load Reduction (MW)			IPL Plans to Offer in 2012 and Beyond
			current	proposed	total	
INCENTIVE-BASED						
Spinning Reserves	Demand-side resource that is synchronized and ready to provide solutions for energy supply and demand imbalance within the first few minutes of an Emergency Event.	No	0	0	0	Monitor—lower value (prices) than energy demand response and unique or specialized resource makes this a low priority.
Regulation Service	A type of Demand Response service in which a Demand Response increase and decreases load in response to real-time signals from the system operator. Demand Resources providing Regulation Service are subject to dispatch continuously during a commitment period. This service is usually responsive to Automatic Generation Control (AGC) to provide normal regulating margin. Also known as regulation or regulating services, up-regulation and down-regulation.	No	0	0	0	Monitor— lower value (prices) than energy demand response and unique or specialized resource makes this a low priority.
TIME-BASED						
Critical Peak Pricing	Rate and/or price structure designed to encourage reduced consumption during periods of high wholesale market prices or system contingencies by imposing a pre-specified high rate or price for a limited number of days or hours.	No	0	0	0	Monitor—requires advanced metering technology.
Critical Peak Pricing with Load Control	Demand-side management that combines direct load control with a pre-specified high price for use during designated critical peak periods, triggered by system contingencies or high wholesale market prices.	No	0	0	0	Monitor—requires advanced technology to control customers' appliances.
Peak Time Rebate	Peak time rebates allow customers to earn a rebate by reducing energy use from a baseline during a specified number of hours on critical peak days. Like Critical Peak Pricing, the number of critical peak days is usually capped for a calendar year and is linked to conditions such as system reliability concerns or very high supply prices.	No	0	0	0	Monitor—requires advanced metering technology

[1] *2010 Assessment of Demand Response and Advanced Metering*, Appendix C: Survey Glossary, Federal Energy Regulatory Commission, pages 56-62, February 2011.

Demand Response Programs						
Classification	Definition[1]	IPL Offer Today	IPL Potential Peak Load Reduction (MW)			IPL Plans to Offer in 2012 and Beyond
			current	proposed	total	
INCENTIVE-BASED						
Real-Time Pricing	Rate and price structure in which the retail price for electricity typically fluctuates hourly or more often, to reflect changes in the wholesale price of electricity on either a day-ahead or hour-ahead basis.	No	0	0	0	Monitor Iowa Day-Ahead Hourly Pricing Program.
System Peak Response Transmission Tariff	The terms, conditions, and rates and/or prices for customers with interval meters who reduce load during peaks as a way of reducing transmission charges.	No	0	0	0	Not applicable—IPL does not own transmission assets.
Time-of-Use Pricing	A rate where usage unit prices vary by time period, and where the time periods are typically longer than one hour within a 24-hour day. Time-of-use rates reflect the average cost of generating and delivering power during those time periods.	Yes	<0.5	0.5	1	Enhance—In IPL Electric Rate Case (docket no. E001-GR-10-276), IPL filed revised time-of-use tariffs for residential, commercial, industrial and institutional customers. The proposed energy charges and peak periods have been adjusted to encourage participation.
Total IPL 2012 Demand Response Potential Peak Load Reduction (MW)			1.4	4.7	**6.1**	

Table Summary: IPL's current demand response programs total 1.4 MW of potential peak load reduction. IPL is proposing enhancements to two existing demand response programs and the addition of one new demand response program that will total an additional 4.7 MW of potential peak load reduction. Altogether, IPL plans to offer in 2012 and beyond demand response programs that will potentially reduce IPL's system peak load by approximately 6.1 MW. Based on IPL's 2010 summer system peak of 151.8 MW, this represents a four percent demand savings of IPL's system peak.

[1] *2010 Assessment of Demand Response and Advanced Metering*, Appendix C: Survey Glossary, Federal Energy Regulatory Commission, pages 56-62, February 2011.

March 2011

Residential Energy-Use Study: Appliance and Equipment Saturation

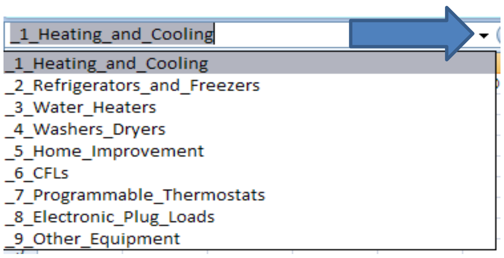
Methodology / How to Read This Report

The crosstabs in this file are drawn from the Nielsen Claritas Energy Audits for 2009 and 2010, yearly surveys of about 32,000 residential customers in the U.S. on a variety of energy-related topics. All analysis was done on weighted data in MarketSight, an online statistical software package.

This file has sections for:

1. Heating and Cooling
2. Refrigerators and Freezers
3. Water Heaters
4. Clothes Washers and Dryers
5. Home Improvement
6. Compact Fluorescent Lamps
7. Programmable Thermostats
8. Electronic Plug Loads
9. Other Equipment

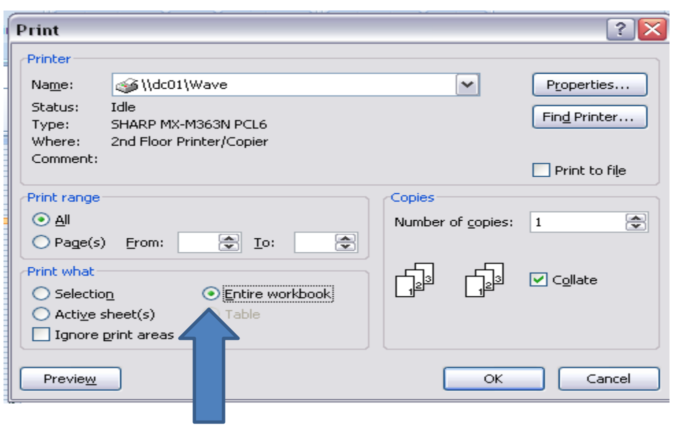
You can jump immediately to any of these sections by using Excel's bookmark feature: Go to the upper left-hand part of your screen, below the menu bar, where you usually see the name of the cell you are currently in. Then, click the downward-facing triangle—a drop-down menu will appear, and you can select which section you would like to jump to. You can also access this menu at any time by pressing **F5** on your keyboard.



To quickly navigate from tab to tab, press **Ctrl + Page Down** on your keyboard to move forward one tab and **Ctrl + Page Up** to move backward one tab. You can also simply click on the tab you want.

Printing This Report

To print a single tab, go to the tab you want to print and use the normal print command for your version of Excel. (You can always press **Ctrl + p** to print in any version of Excel.) To print the entire file, again use the normal print command for your version of Excel, but on the Print dialogue box, under "Print what," select "Entire workbook."



For More Information

Aleana Reeves
Product Manager, Residential Energy Service
E Source
aleana_reeves@esource.com
303-345-9172

Appliance Saturation:

1. Heating and Cooling

Type of Cooling Equipment by Comparison Region

	Census region				
	National total	Northeast (C)	Midwest (D)	South (E)	West (F)
Q: Please indicate the primary type of cooling equipment used in your home or apartment.					
Type of cooling equipment					
Sample size	32,142	5,888	7,109	11,891	7,254
Window or wall-mounted unit (%)	19	**40 DEF**	**20 EF**	**11**	**15 E**
Ceiling/room fans (%)	7	**13 DE**	**7 E**	**2**	**12 DE**
Central air conditioner (%)	64	**36**	**67 CF**	**84 CDF**	**50 C**
Other (%)	2	**1**	**1**	**1**	**6 CDE**
Don't know (%)	1	1	**1**	**1**	**1 DE**
Don't have cooling system (%)	7	**9 DE**	**5 E**	**1**	**17 CDE**

		AC Install	WH Install	AC Cumm	WH Cumm	AC kW	WH kW	kw + WH	AC only kWh	6% Line loss AC & Wh kW	6% Line Loss AC only kWh	Credits $8/AC	Credits $2/WH
2013	June	200	25	200	25	160	5	165	266	176	283	$ 1,600.00	$ 50.00
	July	200	25	400	50	320	10	330	532	351	566	$ 3,200.00	$ 100.00
	August	200	25	600	75	480	15	495	798	527	849	$ 4,800.00	$ 150.00
	September	200	25	800	100	640	20	660	1064	702	1132	$ 6,400.00	$ 200.00
											2830	$ 16,000.00	$ 500.00
2014	June	300	63	1100	163	880	33	913	1463	971	1556	$ 8,800.00	$ 326.00
	July	300	62	1400	225	1120	45	1165	1862	1239	1981	$ 11,200.00	$ 450.00
	August	300	62	1700	287	1360	57	1417	2261	1508	2405	$ 13,600.00	$ 574.00
	September	300	62	2000	349	1600	70	1670	2660	1776	2830	$ 16,000.00	$ 698.00
											8772	$ 49,600.00	$ 2,048.00
2015	June	441	90	2441	439	1953	88	2041	3247	2171	3454	$ 19,528.00	$ 878.00
	July	441	90	2882	529	2306	106	2411	3833	2565	4078	$ 23,056.00	$ 1,058.00
	August	441	90	3323	619	2658	124	2782	4420	2960	4702	$ 26,584.00	$ 1,238.00
	September	441	83	3764	702	3011	140	3152	5006	3353	5326	$ 30,112.00	$ 1,404.00
											17559	$ 99,280.00	$ 4,578.00

Assumptions

One AC unit = 0.8 kW demand savings
One AC unit = 1.33 kWh energy savings per cycling event
One WH unit = 0.2 kW demand savings
One WH unit = 0 kWh energy savings

One AC unit = $8 per month (June, July, August & September)
One WH unit = $2 per month (June, July, August & September)

This is the August peak number using AC & WH combined
2,828 kW (AC) + 132 kW (WH) = 2,960 kW

Customer participation

Customer impacts

March 2011

Residential Energy-Use Study: Appliance and Equipment Saturation

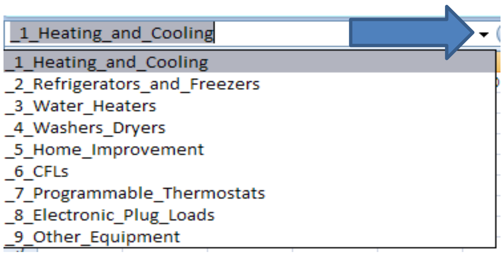
Methodology / How to Read This Report

The crosstabs in this file are drawn from the Nielsen Claritas Energy Audits for 2009 and 2010, yearly surveys of about 32,000 residential customers in the U.S. on a variety of energy-related topics. All analysis was done on weighted data in MarketSight, an online statistical software package.

This file has sections for:

1. Heating and Cooling
2. Refrigerators and Freezers
3. Water Heaters
4. Clothes Washers and Dryers
5. Home Improvement
6. Compact Fluorescent Lamps
7. Programmable Thermostats
8. Electronic Plug Loads
9. Other Equipment

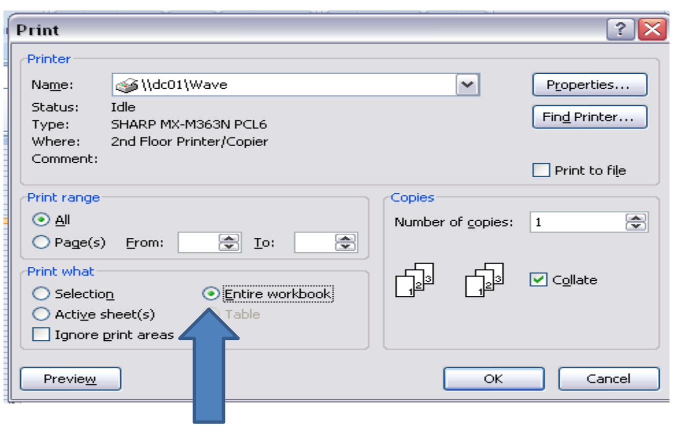
You can jump immediately to any of these sections by using Excel's bookmark feature: Go to the upper left-hand part of your screen, below the menu bar, where you usually see the name of the cell you are currently in. Then, click the downward-facing triangle—a drop-down menu will appear, and you can select which section you would like to jump to. You can also access this menu at any time by pressing **F5** on your keyboard.



To quickly navigate from tab to tab, press **Ctrl + Page Down** on your keyboard to move forward one tab and **Ctrl + Page Up** to move backward one tab. You can also simply click on the tab you want.

Printing This Report

To print a single tab, go to the tab you want to print and use the normal print command for your version of Excel. (You can always press **Ctrl + p** to print in any version of Excel.) To print the entire file, again use the normal print command for your version of Excel, but on the Print dialogue box, under "Print what," select "Entire workbook."



For More Information

Aleana Reeves
Product Manager, Residential Energy Service
E Source
aleana_reeves@esource.com
303-345-9172

Appliance Saturation:

3. Water Heaters

Water Heaters by Comparison Region

	Census region				
	National total	Northeast (C)	Midwest (D)	South (E)	West (F)
Q: Please indicate which of the following items you have in or around your home. K. Water heater					
Have water heater					
Sample size	32,142	5,888	7,109	11,891	7,254
No (%)	23	**34 DEF**	**19**	**19**	**22 DE**
Yes (%)	77	**66**	**81 CF**	**81 CF**	**78 C**
Q: Please indicate the primary type of water heater used in your home.					
Water heater type					
Sample size	24,904	3,859	5,777	9,632	5,636
Natural gas or propane water heater (%)	49	**54 E**	**64 CEF**	**31**	**61 CE**
Electric water heater (%)	48	**41 DF**	**34**	**66 CDF**	**35**
Tankless natural gas or propane water heater (%)	2	**3 DE**	**1**	**1**	**2 DE**
Tankless electric water heater (%)	1	**2 DEF**	**0**	**1 D**	**1 D**
Solar water heater (%)	0	**0**	**0**	**1 D**	**1 CD**

ACTION PLAN

7.0 General

The resources needed to meet IPL's system capacity and energy requirements come primarily from two types of resources; demand-side and supply-side (conventional and renewable) resources. The action plan is focused on the next five year time period. IPL plans to:

- Continue to pursue DSM activities;
- Investigate and pursue renewable energy alternatives, including solar to meet the future MN requirement;
- Purchase capacity in the short term to satisfy MISO Resource Adequacy obligations;
- Complete construction of the approximate 650 MW MGS combined cycle facility;
- Pursue capacity and efficiency upgrades at Tier 1 coal-fired units;
- Pursue reasonable emission controls and/or natural gas conversions on its remaining coal-fired units;
- Retire older peaking units;
- Retire older intermediate steam units;
- Fuel switch the Sutherland CTs from oil to natural gas operations; and
- Consider all supply-side options and only commit to resources that are in IPL's and IPL's customers' best interest.

In addition, IPL is engaged in transmission and environmental related activities which are discussed below. The analysis of all options is ongoing.

7.1 Demand-Side Management Activities

IPL's current DSM programs have been aggressively pursued and are continuing to save kW and kWh. DSM activity is reported annually in all regulatory jurisdictions in which IPL serves retail customers. These filings on DSM programs to various agencies are expected to continue.

For this filing, the impacts of adding new DSM programs and measures were analyzed. IPL will continue to analyze potential demand and energy savings from future DSM activities.

7.2 Supply-Side Activities

IPL is committed to meeting the demands of its customers. In Section 5, the types of resources required to meet IPL's customer needs were identified. Without resource additions other than MGS, IPL projections show a short-term capacity shortfall in 2015 and 2016, and then no shortfall until 2023, with a significant capacity shortfall in 2025. IPL plans to meet its resource needs consistent with the regulations of the governing jurisdictions. Considering the next five years, the immediate incremental capacity and energy needs through

2019 will most likely be met with existing resources, MISO market energy, capacity purchases in 2015 and 2016 (as necessary), and the installation of MGS in 2017.

In this Resource Plan, IPL considered the ongoing viability of its older peaking and intermediate steam units. As discussed in Section 6, IPL plans to [TRADE SECRET DATA BEGINS Retirements TRADE SECRET DATA ENDS] are subject to approval from the MISO through the Attachment Y process.

[TRADE SECRET DATA BEGINS At its TRADE SECRET DATA ENDS] Tier 2 unit Kapp 2 will fuel switch from coal to natural gas operation in the spring of 2015. At its Tier 1 coal-fired units Neal 3 and 4, Louisa, Ottumwa, and Lansing 4, IPL will install emission controls for MATS compliance, and IPL will pursue capacity and efficiency upgrades.

IPL will switch fuel from oil to natural gas at the Sutherland CTs in 2017.

The Resource Plan includes the committed construction and installation of the approximate 650 MW MGS combined cycle facility in 2017.

IPL customers' demands will be met, system reliability within the region will be maintained, and customers' rates will be kept as low as reasonably possible. This action plan will continually be reviewed and revised, as new information with respect to IPL's resource needs becomes available. IPL's resource planning process is continuously iterative and Electric Integrated Resource Plans are regularly filed in Minnesota and Iowa. In the interim, all resource options will continue to be considered and evaluated.

7.3 Renewable Activities

IPL continues to consider certain renewable energy technologies, especially wind energy, viable options for future resource needs. Currently, IPL purchases capacity and energy from approximately 250 MW nameplate of wind turbines. Also, IPL's 200 MW Whispering Willow Windfarm – East came online at the end of 2009. These existing resources are expected to allow IPL to reach a renewable energy portfolio of over 8 percent in the next five years. As renewable purchase agreements expire, IPL's renewable portfolio will decline (before considering future resource additions). For renewable reporting purposes, IPL allocates this renewable energy between its Iowa and Minnesota jurisdictions.

To satisfy Iowa renewable requirements[1], IPL must secure 49.8 MW of nameplate renewable capacity. IPL has satisfied this requirement and assigned this capacity to a 65.1% share of the Storm Lake Power Partners Windfarm.

[1] Iowa Administrative Code 199-15.11(1).

Based on typical capacity factors from Storm Lake Power Partners, this 49.8 MW share equates to approximately 118,000 MWH per year, or 0.8% of Iowa annual retail energy sales. As shown in Appendix 7A, IPL is projecting a surplus of over 1,000,000 MWH per year relative to Iowa's current renewable energy requirements for the next ten years. This surplus declines as renewable agreements expire (before resource additions), but is still more than adequate to meet Iowa requirements.

The Minnesota Renewable Energy Standard[2] sets minimum requirements for renewable energy generation as a percentage of retail energy sales:

- 12% by 2012
- 17% by 2016
- 20% by 2020
- 25% by 2025

As shown in Appendix 7A, IPL has a current "bank" of approximately 37,700 renewable energy credits ("REC" / "RECs"). Even with this REC bank, without further action IPL will fall short of Minnesota's renewable requirements in 2014. The Minnesota shortfall is roughly:

- 23,000 RECs per year in 2013 to 2015 for the 12% requirement,
- 67,000 RECs per year in 2016 to 2019 for the 17% requirement,
- 103,000 RECs per year in 2020 to 2024 for the 20% requirement,
- Over 150,000 RECs per year in 2025 to 2029 for the 25% requirement.

Note that these values represent IPL's position before the accumulation of any future resource additions identified in this Resource Plan.

When considering IPL's Minnesota and Iowa service territories collectively, IPL's surplus in Iowa could be used to meet a deficit in Minnesota. Further, expansion plans for the 2014 IRP include significant wind additions, such that new and existing wind constitutes approximately 25% of the energy portfolio. Therefore, IPL in total is well positioned to meet both its Minnesota and Iowa renewable energy requirements through the study period (2029) absent any purchases of Midwest Renewable Energy Tracking System (M-RETS) Certificates.

IPL's Renewable Energy Production is shown in Appendix 7B and IPL's Annual Community-Based Energy Development (C-BED) Report is included in Appendix 7C. Since IPL's C-BED tariff was approved, IPL has not received any proposals pursuant to its C-BED tariff.

In summary, IPL is well positioned to comply with both Iowa's and Minnesota's renewable energy requirements. Beyond compliance, IPL will continue to consider renewable energy in its future resource decisions.

---

[2] Minnesota Statutes 216B.1691.

7.4 Solar Requirements

The recently passed Minnesota Solar Energy Standard (SES) requires IPL to generate or procure sufficient solar energy to serve 1.5 percent of its Minnesota retail load, with at least 10 percent of the 1.5 percent to be served from PV with a nameplate of 20 kilowatts or less. This requirement is separate from the Minnesota 25 percent renewable standard previously discussed.

In an August 14, 2013, data request response in Docket E999/CI-13-542, IPL estimated SES requirements of roughly 14,670 MWH. Based on the generic 20.5% solar capacity used for new units in this Resource Plan, IPL estimates solar installations of roughly 8 MW for compliance. In the 2014 Resource Plan IPL set EGEAS modeling constraints such that a minimum of 10 MW of solar was selected by 2020 to capture the impact of the SES on the expansion plan. The optimization modeling could select more, if economic. The EGEAS output results did not select any more than the minimum amount required.

7.5 Transmission Activities

On December 20, 2007, IPL sold its transmission assets to ITC-M. ITC-M is a subsidiary of ITC Holdings. ITC-M is an independent transmission company which provides non-discriminatory access to those entities who depend upon the transmission grid. The transaction involved the sale of approximately 6,800 miles of 34.5 kV and higher voltage transmission lines in Iowa, Minnesota, Illinois and Missouri. The transaction, examined by the Commission in Docket No. E-001/PA-07-540, was approved in a written order dated February 7, 2008, with an effective date of December 18, 2007. As a result of the transaction, IPL's status has changed from one of a Transmission Owner (TO) to a Transmission Dependent Utility (TDU).

As a TDU, IPL participates in the planning and stakeholder processes of both MISO and ITC-M. In addition, IPL participates in various ad hoc transmission activities. IPL plans to remain active in transmission planning activities as a TDU.

7.6 Environmental Activities

Environmental activities impact many aspects of IPL's business, including its generation planning and energy supply decision-making. IPL must develop plans to make major equipment retrofits and/or add new generation sources many years in advance to allow adequate time to arrange financing, obtain necessary approvals and permits, accomplish engineering design, and complete the actual construction. IPL's primary goal in evaluating regulatory developments is to ensure compliance with applicable environmental requirements for air emissions, water and waste management. Furthermore, IPL considers regulatory developments with an objective to select appropriate emissions control technologies or implement operational measures that will be highly efficient and cost-effective while reducing overall environmental impacts. This approach balances achieving environmental compliance objectives with minimizing impacts on customers' energy costs while also preserving natural resources and protecting wildlife.

7.6.1 Planning for Environmental Regulations

Environmental planning requires evaluating regulations and understanding associated impacts to IPL's utility operations. The environmental regulatory framework governing air quality requirements is a critical component to developing a flexible emissions strategy that can be changed in response to revisions to existing regulations or issuance of new rules. The framework for implementing rules issued under the authority of the Clean Air Act (CAA) is discussed in Section 7.6.2. Section 7.6.3 provides an overview of the critical air quality rules that IPL is currently considering in its emissions planning efforts. In addition, Section 7.6.4 provides a summary of how proposed water quality regulations are anticipated to impact IPL's power plant operations. Section 7.6.5 summarizes potential new or revised waste management regulations that could affect coal combustion byproduct re-use, ash handling or landfill practices at IPL.

IPL monitors the status of environmental rules and regulations that may be subject to change. Additional ambiguity and uncertainty enters the rulemaking process due to litigation of environmental requirements. There is currently significant regulatory uncertainty with respect to the various environmental rules and regulations discussed below. Until litigation on various environmental rules is resolved in the courts or with further action by the EPA, IPL plans to continue to implement its current multi-emissions compliance plan.

Details of the potential impacts of various environmental regulations and IPL’s plan to address the anticipated compliance requirements are provided in IPL's Emissions Plan and Budget (EPB) filing, IUB Docket No. EPB-2014-0150, as discussed in section 7.7.1. IPL will closely monitor the future developments of emerging environmental rules as well as associated legal challenges to these requirements and continue to review its multi-emissions compliance plans with regulators to determine if changes are necessary.

7.6.2 Framework Governing Issuance of Air Quality Rules

The federal CAA along with its various amendments provides the framework governing air quality regulations, including emissions compliance requirements for the electric utility industry. The CAA defines the role of federal government and state agencies. Under the CAA, the EPA sets limits on how much of an air pollutant can be in the atmosphere anywhere in the United States. This ensures that all Americans have the same basic health and environmental protections. For IPL, the Minnesota Pollution Control Agency (MPCA) and the Iowa Department of Natural Resources (IDNR) are the state agencies that implement federal environmental rules in Minnesota and Iowa, respectively.

Preservation of air quality is maintained through existing regulations and periodic reviews to ensure adequacy of these provisions based on scientific data. As part of the basic framework under the CAA, the EPA is required to establish National Ambient Air Quality Standards (NAAQS), which serve to protect public health and welfare. These standards address six "criteria" pollutants that are common and found all over the United States. The EPA uses criteria pollutants as indicators of air quality. Areas that comply with NAAQS are considered to be in attainment, whereas routinely monitored locations that do not comply with these standards may be classified by the EPA as non-attainment and require further actions to reduce emissions.

Four of these criteria pollutants are particularly relevant to IPL's electric utility operations: nitrogen oxide (NO_x), sulfur dioxide (SO_2), particulate matter (PM), and ozone. Ozone is not directly emitted from IPL's generating facilities; however, NO_x emissions may contribute to ozone formation in the atmosphere. Fine particulate matter ($PM_{2.5}$) may also be formed in the atmosphere from SO_2 and NO_x emissions that react to form sulfate and nitrate aerosols. The CAA also regulates 187 toxic air pollutants, also known as hazardous air pollutants (HAPs), including mercury. In 2009, the EPA commenced regulation of six greenhouse gases (GHGs) including carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs), and perfluorocarbons (PFCs).

State implementation plans (SIPs) document the collection of regulations that individual state agencies will apply to maintain NAAQS and other CAA emissions requirements. The EPA must approve each SIP, and if a SIP is not acceptable to the EPA or if a state chooses not to issue separate state rules, then the EPA can assume enforcement of the CAA in that state (in whole or part) by issuing a federal implementation plan (FIP).

Additional emissions requirements may also be applied under the CAA regulatory framework and are generally implemented using one of two policy approaches, either command-and-control or market-based cap-and-trade. In a command-and-control approach, the EPA issues regulations that mandate specific standards of performance, such as achieving a percent of control or a minimum level of emission. These limits are generally applied to each emitting unit individually, although in some instances, averaging of emissions is allowed at the facility-level in order to provide additional compliance flexibility. In a market-based cap-and-trade approach, an overall limit, or "cap," is set for the allowed emissions level. Regulated facilities receive authorizations to emit in the form of emissions allowances, with the total amount of allowances limited by the cap. Each regulated facility can determine its own compliance strategy to meet the overall reduction requirement, including sale or purchase of allowances, installation of pollution controls, or other operational changes that will reduce emissions. Individual control requirements are not specified under a cap-and-trade program, but each regulated facility must surrender allowances equal to its actual emissions in order to comply.

The CAA also addresses new or modified emissions sources through the New Source Review (NSR) permitting program. NSR permitting ensures that air quality is not significantly degraded in areas that currently achieve the NAAQS, known as Prevention of Significant Deterioration (PSD) permits. It also requires more stringent controls in areas that exceed the NAAQS, known as non-attainment NSR permits. The NSR program also requires PSD permitting in order to regulate GHG emissions increases from certain new or modified sources. The NSR process requires industry to undergo a pre-construction review for environmental controls when building new facilities or making modifications to existing facilities that would result in a significant increase of a regulated air pollutant.

7.6.3 IPL Planning Considerations for Air Emissions Regulations

The following briefly discusses the primary CAA programs and associated air quality regulatory requirements that IPL is currently considering for its multi-emissions control strategy. Specifically, the federal and state air emission regulations currently applicable to IPL's operations include the Clean Air Interstate Rule (CAIR) and Utility Maximum Achievable Control Technology (MACT) standards. IPL operations will also comply with the environmental requirements from other CAA rules as they are issued, such as changes to the NAAQS or a future emissions transport regulation to replace the CAIR program. However, these currently are not significant drivers of the emissions reductions and air pollution controls that are needed from the IPL generation fleet. The impact of these other regulations will be assessed upon their final issuance and IPL compliance plans adjusted if necessary.

CAIR

In May 2005, the EPA issued the CAIR to address CAA requirements that air pollution created in an upwind state does not add to unhealthy pollution levels in downwind states. This is commonly referred to as the CAA “good neighbor” provision. The purpose of the CAIR was to limit the transport of NO_x and SO_2 emissions from certain states in the eastern United States, because these emissions were found to contribute to the downwind formation of fine $PM_{2.5}$ and ozone at levels above the EPA's NAAQS. The EPA issued allowed budgets for NO_x and SO_2 in order to limit emissions coming from each CAIR-regulated state. Furthermore, the CAIR provided a regulatory framework that allowed states to achieve required NO_x and SO_2 emission reductions from fossil-fueled power plants through participation in an EPA-administered market-based cap-and-trade system.

In July 2008, the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit Court) vacated the CAIR in its entirety (State of North Carolina v. Environmental Protection Agency, No. 05-1244). In response, the EPA and other affected parties filed petitions requesting the D.C. Circuit Court review the decision, including a request that the CAIR be remanded to the EPA for reconsideration and not vacated in its entirety, as originally decided. In December 2008, the D.C. Circuit Court issued an order that denied rehearing of the original court decision, but decided to remand rather than vacate the CAIR. This decision effectively left the CAIR in-place while EPA worked to address the rule’s flaws identified in the court’s July 2008 opinion. Therefore, in the interim, the CAIR emission reduction obligations became effective for NO_x on January 1, 2009, and for SO_2 on January 1, 2010. These specific reduction obligations will remain in place until a final CAIR replacement rule is issued by the EPA. In December 2009, the EPA also issued a final rulemaking that stayed the effectiveness of the CAIR emissions reductions for sources located in Minnesota. Therefore, the CAIR requirements currently apply only to IPL's fossil-fueled electric generating units (EGUs) greater than 25 megawatts (MW) located in Iowa.

The CAIR provided for a large regional cap-and-trade system and did not restrict the amount of emission allowances that could be traded between different states. In addition, the CAIR sought to harmonize this regulation with the existing Acid Rain Program (ARP), which is a market-based cap-and-trade rule that requires SO_2 reductions from electric utilities. In particular, EGUs are allowed to apply ARP SO_2 allowances for compliance with both rules. However, to gain additional emissions reductions under the CAIR, the EPA required these SO_2 allowances to be surrendered at a higher rate. Each allowance under the CAIR Phase I program is equivalent to 50% of an ARP allowance (i.e., a 50% reduction). Similarly, each allowance under the CAIR Phase II program beginning in 2015 would be equivalent to 35% of an ARP allowance (i.e., a 65% reduction). The CAIR also created new annual and ozone season NO_x allowances that are traded at one ton per allowance. Furthermore, existing EGUs continue to receive ARP and CAIR allowances in perpetuity, even if a unit is retired.

In August 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR) to replace the CAIR program. Similar to the CAIR, the CSAPR established NO_x and SO_2 emission budgets for fossil-fueled EGUs located in the eastern half of the United States. The first phase of the CSAPR was intended to commence on January 1, 2012. In addition, a second phase of the CSAPR, with lower NO_x and SO_2 emission budgets, was intended to commence on January 1, 2014. CSAPR would have applied to IPL's EGUs located in both Minnesota and Iowa.

The requirements of the CSAPR never took effect because it was stayed by the D.C. Circuit Court in December 2011 and subsequently vacated by the same court in August 2012 in response to several legal challenges (EME Homer City Generation, L.P. v. Environmental Protection Agency, et. al., No. 11-1302). In October 2012, the EPA asked for a rehearing of the CSAPR case from the full D.C. Circuit Court ("en banc rehearing"), but this request was denied in January 2013. In response, the EPA successfully petitioned the U.S. Supreme Court to review the D.C. Circuit Court CSAPR decision. The U.S. Supreme Court heard oral arguments on the CSAPR decision in December 2013. A decision from the U.S. Supreme Court on the CSAPR is expected in the first half of 2014.

At this time, IPL anticipates one of the following three outcomes, or some combination thereof, regarding interstate transport during 2015 and 2016:

1. The CAIR continues to be implemented (Phase II reductions for both SO_2 and NO_x begin in 2015);

2. The CSAPR is reinstated, assuming a U.S. Supreme Court decision in the EPA's favor. This scenario would likely require the EPA to re-evaluate and update the CSAPR budgets and adjust the compliance timeframes; or
3. The EPA issues a new rule to address interstate transport of air pollutants. In fact, the EPA announced in January 2014 that a new rule will be proposed to replace the CSAPR in October 2014. Unlike the CSAPR, the EPA stated that this new rule would only address the ozone NAAQS and not the fine particulate matter NAAQS. This means emission reductions would likely only be established for NO_x. The EPA has stated that the purpose of this rule would be to help states meet the 2008 ozone NAAQS of 75 parts per billion (ppb) by reducing emissions transported across state boundaries. If the EPA moves forward with this plan, a final rule would be anticipated sometime in late 2015 with compliance beginning sometime thereafter.

IPL's plans currently comply with the emissions requirements under CAIR including the Phase II reductions that will commence starting in January 2015. In the event that either CSAPR is reinstated or a new rule is issued for interstate transport, IPL expects that there will be opportunity to provide input through public comment and expects sufficient time will be available to adjust plans, if needed, in order to support implementation of these future regulatory requirements.

Utility MACT Rule

In 2009, the EPA announced its intention to develop MACT rules for EGUs, pursuant to Section 112 of the CAA, to reduce emissions of mercury and other federal HAPs. The CAA Section 112 requires a command-and-control technology driven approach to develop MACT standards. The MACT standards are designed to reduce HAPs emissions to a maximum achievable degree, taking into consideration the cost of reductions, non-air quality health effects, environmental impacts and energy requirements.

In March 2011, the EPA issued the proposed Utility MACT rule for fossil-fueled EGUs, also referred to as the "Mercury and Air Toxics Standards" ("Utility MATS"). In February 2012, the EPA published the final Utility MATS in the Federal Register making this rule effective for coal and oil-fired EGUs. The MATS applies to IPL's coal-fired EGUs in Iowa, but does not apply to any EGUs in Minnesota because these are natural gas-fired only.

The final rule requires coal-fired EGUs to comply with emission limits for mercury, filterable PM as a substitute for non-mercury metal HAPs and hydrogen chloride (HCl) as a substitute for acid gas HAPs. The EPA also proposed alternative standards for total or individual non-mercury metals emissions (instead of filterable PM) and SO_2 emissions (instead of HCl for acid gases if a scrubber is installed). In addition, work practice standards were proposed for organic HAP emissions to ensure proper combustion.

The structure of the MATS rule is fundamentally different than that of CAIR's cap-and-trade approach. The final standards establish applicable emission limitations, measured either in terms of heat input (lb/MMBtu) or gross output (lb/MWh). EGUs must achieve these emission rate limitations on a 30 operating day rolling basis. Although emissions rate averaging at a facility with multiple EGUs is allowed, IPL fleet-wide emissions averaging is not permissible. In addition, no emissions allowances or emissions trading options exist.

The compliance deadline for the Utility MATS is April 16, 2015. However, an entity can request an additional fourth year for compliance, which may be granted on a case-by-case basis by state permitting authorities for units that are needed to assure power reliability, units repowering to gas, or units that need additional time to install air pollution control technology.

The Utility MATS rule remains subject to legal challenges and oral arguments for this case (White Stallion Energy Center, LLC v. EPA) took place in the D.C. Circuit court in December 2013. A decision in this case is anticipated in 2014. In addition, in June 2013, the EPA re-opened the public comment for the provisions related to EGU startup and shutdown practices of the MATS rule. EPA's final rule reconsideration for the startup and shutdown provisions is expected in 2014. At this time, IPL does not anticipate significant changes to the MATS emissions limitations or compliance deadlines as a result of the litigation or rule reconsideration. IPL's current emissions plans for its Iowa coal-fired EGUs support compliance with the EPA's issued MATS requirements.

7.6.4 IPL Planning Considerations for Water Quality Regulations

IPL considers compliance with current and future revisions to water quality regulations in its environmental planning efforts. These Federal Clean Water Act (CWA) requirements are considered by IPL in conjunction with future revisions anticipated to regulations affecting ash management practices at IPL's coal-fired EGUs. Together the approach implemented for compliance with these regulatory requirements at IPL's existing EGUs is expected to reduce water consumption, as well as, assure no adverse potential effects on aquatic life from water intake and discharge as part of its resource plan.

Thermal Discharge Rule – 316(a)

Section 316(a) of the CWA requires the EPA to regulate thermal impacts from wastewater discharges of industrial facilities, including those from EGUs. States have authority to establish standards for these thermal discharges in order to minimize adverse environmental impacts to aquatic life. Therefore, the IDNR is required to regulate thermal impacts from wastewater discharges of industrial facilities, including IPL facilities that discharge water into nearby rivers and streams. Compliance with the thermal rules will be evaluated on a case-by-case basis when wastewater discharge permits for IPL's generating facilities are renewed. Exceptions to the thermal limitation requirements are allowed under the temperature variance provisions of Section 316(a). Under this provision of the CWA, permittees must demonstrate that the variance for the thermal component of the discharge assures the protection and propagation of a balanced, indigenous population of shellfish, fish and wildlife in the receiving water.

IPL is currently addressing the need for thermal discharge requirements on a case-by-case basis with the IDNR as each power plant National Pollutant Discharge Elimination System (NPDES) permit becomes subject to renewal. Compliance planning activities required under Section 316(a) include performing thermal studies, possible variance application preparation, compliance monitoring, and, if required, the installation of control equipment to minimize the impacts of the plant's thermal discharge on the receiving stream. To determine the appropriate site limitations, thermal modeling studies are conducted as deemed necessary and submitted to the IDNR for review and determination that the resulting thermal discharge limitation established based on these studies for the permittee complies with Section 316(a) of the CWA.

IPL is currently obtaining 316(a) variances at two sites with active NPDES permits, M.L. Kapp and Prairie Creek Generating Stations. However, IPL also expects that 316(a) modeling and variances will be necessary for the discharges at other electric generating facilities including Burlington, Dubuque, and Lansing. IPL currently has based its 316(a) compliance plan on the assumption that thermal variances can be obtained for each of these affected facility as necessary based on study outcomes, because of the cost compared to the benefits of installing and operating cooling towers. The Fox Lake generating facility has previously received a thermal variance from MPCA in its NPDES permit. In addition, the Ottumwa Generation Station currently operates a cooling tower that helps to minimize thermal impacts and further actions currently are not planned for this site.

Cooling Water Intake Structure Rule – 316(b)

Section 316(b) of the CWA requires that NPDES permits for facilities with cooling water intake structures ensure that the location, design, construction, and capacity of the structures reflect the "best technology available" or "BTA" to minimize harmful impacts to fish and other aquatic life. More specifically, this rule will require existing power plants to demonstrate how they currently meet or will meet national performance standards to reduce the mortality of fish and shellfish caused by entrainment (taking in of organisms with the cooling water) and impingement (blocking of larger entrained organisms that enter the cooling water intake by some type of physical barrier – sometimes referred to as entrapment).

This EPA regulation became effective in 2004 and applies to existing cooling water intake structures at large steam EGUs. In 2007, a court opinion invalidated aspects of the Section 316(b) regulation, which allowed for consideration of cost-effectiveness when determining the appropriate compliance measures. As a result, the EPA formally suspended the Section 316(b) regulation in 2007. In 2009, the U.S. Supreme Court granted the EPA authority to use a cost-benefit analysis when setting technology-based requirements under Section 316(b). In April 2011, the EPA issued a revised proposed Section 316(b) Rule, which applies to existing and new cooling water intake structures at large steam EGUs. The proposed rule would require that both impingement and entrainment mortality standards be met for power plants that withdraw greater than two million gallons of cooling water per day. Facilities can install technology to meet the impingement standard or reduce the cooling water intake velocity to below a set standard (0.5 feet/second). State agencies will be tasked with determining the best approach to comply with the entrainment standard. Part of this determination will include consideration of a series of factors such as cost and social benefits.

IPL has identified seven electric generating facilities that may be impacted by the revised Section 316(b) Rule: Burlington Unit 1; Dubuque Units 3 and 4; Fox Lake Units 1 and 3; Lansing Unit 4; M.L. Kapp Unit 2; Ottumwa Unit 1; and Prairie Creek Units 3 and 4. IPL's Emery Generating Station is not affected because this power plant uses treated sanitary water, also called "grey water", from the local Publicly Owned Treatment Works (POTW) as the primary supply and return. In addition, the Sutherland Generating Station uses groundwater as the main water supply and returns it to the adjacent Iowa River. A final 316(b) rule is expected to be issued by the EPA in April 2014. The schedule for compliance with this rule has not yet been finalized; however, final compliance is expected to be required within eight years of the effective date of the final rule. Despite this, studies and interim compliance requirements must be initiated within six months after the final rule is promulgated. Therefore, IPL anticipates commencing field studies to prepare for 316(b) starting in 2014.

Cooling water intake can adversely impact aquatic organisms in two basic ways. The first is entrainment, which is the taking in of organisms with the cooling water. As these entrained organisms pass through the plant, they are subjected to numerous sources of damage. The second way is through impingement. This is the trapping of organisms that enter the cooling water intake within a physical part of the intake structure. Most electric generating plants have screening equipment installed at the cooling water intake to protect downstream equipment, such as pumps and condensers, from damage or clogging caused by debris. Larger organisms, such as fish, which enter the system and cannot pass through the screening equipment, are trapped at the intake structure. Eventually, if a fish cannot escape or is not removed, it will tire and become impinged on the screening equipment. If impingement continues for a long time period, the fish may suffocate because the water current prevents gill covers from opening. If the fish is impinged for a short time period and removed, it may survive; however, it may still suffer from delayed mortality due to the resulting stress.

IPL evaluated potential impingement and entrainment control technologies to prepare for compliance with a previous version of the Section 316(b) regulations. Installing wedge-wire screens will reduce velocity of cooling intake water withdrawals at a power plant resulting in less entrainment and impingement of fish and other aquatic life. Wedge-wire screens are bullet-shaped devices placed on the bottom of a river that allows water to be withdrawn from a river, lake or stream through small diameter holes (or slots) in the screen. Other control options include retrofitting existing travelling screen equipment at the plant water intake structure with fine mesh screens equipped with wash and fish return systems. Barrier nets (which are basically large mesh nets located up and downstream of the plant's water intake structure) provide reduced velocity across the net, thereby limiting impingement and entrainment. Due to debris present in nearly all water sources, barrier nets are prone to high maintenance.

IPL anticipates that the final Section 316(b) rule will require initial actions for data collection studies, report preparation, and plan development for plants affected by the rule. IPL expects the final rule will allow for pre-approved impingement control technologies to be installed to meet compliance requirements, while entrainment control technology needs will be based on determinations made by IDNR based on information submitted by IPL. It is possible that the IDNR could require cooling towers as the BTA to comply with Section 316(b) entrainment requirements, although, according to the proposed rule, the IDNR is not obligated to do so. IPL currently has not included cooling towers in its Section 316(b) compliance plan.

Effluent Limitation Guideline (ELG)

The EPA is required under the CWA to periodically update the national technology-based regulations to reduce industry discharges of pollutants from effluent wastewater into the waters of the United States. For the electric power sector, the EPA last updated the relevant guidelines for wastewater effluent discharges in 1982. In 2010, the EPA completed an Information Collection Request (ICR) to gather information from utilities to support a future Effluent Limitation Guideline (ELG) rulemaking. The purpose of the ICR to consider various wastewater sources and levels of pollutants in these discharges, such as metals, total dissolved solids (TDS) and total suspended solids (TSS). The proposed rule changes were issued in June 2013 and EPA's final rule is expected in May 2014. It is anticipated that the final rule will result in new discharge limits and compliance schedules that will be incorporated into existing NPDES permits when they come due for renewal, which typically occurs on a five-year cycle. Therefore, compliance with these proposed guidelines would likely be required after July 1, 2017, but before July 1, 2022, depending on each facility's wastewater permit cycle for existing steam EGUs.

The implications of this rulemaking remain uncertain. However, the EPA indicates the revisions will likely result in more stringent effluent limits for wastewater discharges associated with plant process wastewaters, particularly those that involve ash management. In the proposal, the EPA detailed eight compliance options, of which they identified four as preferred options. Based on evaluation of the four preferred options, new limits are likely for seven wastewater discharges. Of the seven wastewater discharges identified, four would impact IPL, including wet fly ash transport water, bottom ash transport water, landfill and surface impoundment leachate, and chemical and non-chemical metal cleaning wastewater. Best Available Technology (BAT) will likely be required to treat wastewater discharges. Information from the EPA suggests that “no discharge” from ash ponds may be BAT, which suggests that closing ash ponds and converting to “dry” or circulating ash management systems may be necessary or desirable to comply with the effluent limitation guideline requirements. In addition, it appears that limits would have to be met before wastewaters are co-mingled, therefore some low-volume wastewater streams will likely be affected, with the possibility of total elimination of discharges that come in contact with ash. The latter appears consistent with the EPA’s proposed Coal Combustion Residuals (CCR) rule changes discussed in Section 7.6.5 below.

The final ELG rules will have varying impacts at all IPL generating facilities. IPL operates nine existing sites that are expected to be impacted by these guidelines, including:

Emery Units 1-3;
Ottumwa Unit 1;
Prairie Creek Units 3-4;
Fox Lake Units 1 and 3;
Lansing Unit 4;
Dubuque Units 3-4;
M.L. Kapp Unit 2;
Burlington Unit 1; and
Sutherland Units 1 and 3.

Currently, IPL’s focus is on managing water discharges from facilities with ash ponds, and investigating options to treat waters that are co-managed in the ash ponds. These waters can include boiler wash down, chemical and non-chemical cleaning wash waters, water treatment system discharges, floor sumps, and coal pile runoff. Control technology options include water reuse, primary and secondary treatment, conversion to alternate ash handling systems, and closing ash ponds. IPL continues to evaluate options for off-site management of chemical and non-chemical cleaning wastewaters.

7.6.5 IPL Planning Considerations for Solid Waste Management Regulations

Coal combustion residuals (CCR) are what remain after the direct combustion of coal in power plants to generate electricity. There are different types of CCR:

- Fly ash is a very fine powder-like particle, ranging in color from tan to black. It is collected by air pollution controls, such as electrostatic precipitators (ESP) and baghouses, which prevent it from being released through the stacks of the plant.
- Bottom ash is a brown sand-like material collected in the bottom of the boilers.
- Boiler slag is black, shiny and angular. It is coarser than bottom ash and also collected in the bottom of boilers.

Passage of the Resource Conservation and Recovery Act (RCRA) in 1976 delegated the regulation of "non-hazardous" waste to each respective state. CCR's met the definition of a non-hazardous waste; hence, each state developed specific regulations for CCR management for their respective jurisdictions. RCRA was amended in 1980 to include what is referred to as the "Bevill Amendment", which specifically exempted CCR from hazardous waste regulation until further study could be completed by EPA. Following extensive studies, the EPA concluded in Regulatory Determinations issued in 1993 and 2000 that CCR wastes did not warrant regulation as hazardous waste under Subtitle C of RCRA. However, in the 2000 Regulatory Determination, the EPA noted that national regulations for CCRs under the "non-hazardous waste" section of RCRA were appropriate when disposed in landfills or surface impoundments. Under the non-hazardous waste designation, CCR is currently regulated by each respective state.

In December 2008, national attention was turned to CCR management when a breach in a coal ash impoundment pond at the Tennessee Valley Authority's plant near Kingston, Tennessee, released 1.1 billion gallons of coal ash slurry to the immediate surrounding area. Following this accidental release, the EPA declared its intent to move forward with coal ash regulations to address the management of CCRs. In June 2010, the EPA issued a proposed rule seeking public comment regarding two potential regulatory options for management of CCRs:

- Option 1: regulate as a special waste under the federal hazardous waste regulations (Subtitle C) when the CCR is destined for disposal, but continue to allow beneficial use applications of CCRs as a non-hazardous material; or
- Option 2: continue to regulate as a non-hazardous waste (Subtitle D) for all applications, but subject to newly developed national standards for CCR management.

Both options include additional requirements with significant impact for CCR management, beneficial use applications and disposal, with the "special waste" designation being the most stringent. As currently proposed, both options would result in all current CCR surface impoundments requiring significant upgrades or being closed with "wet ash collection" systems being converted to "dry ash collection" systems. If it is determined appropriate to manage coal ash as a special hazardous waste, additional costs would be incurred to:

(1) develop and implement new on-site large quantity generator hazardous waste management handling programs; and

(2) site and construct a number of new hazardous waste landfills.

Currently, Iowa does not have any hazardous waste landfills.

While there is some uncertainty regarding what requirements will be contained in a final CCR rule, if a final rule is issued that is similar to the proposed rule, IPL may be required to close active ash ponds and bring all CCR landfills up to minimum engineering design and operating criteria. IPL's plan includes closing all ash ponds, converting ash handling systems to dry or recirculating ash systems, and re-designing the balance of plant wastewater discharge streams. These plans are based on preliminary information provided by the EPA and industry groups, and therefore are subject to change upon issuance of the final CCR rule.

In Iowa, IPL has eight current or former coal generating facilities with one or more existing ash surface impoundments, one facility with a concrete ash collection basin, and two active CCR landfills. In Minnesota, since Fox Lake Generating Station no longer burns coal, there are no planned projects for ash handling conversion although further requirements for the former ash surface impoundments remain under assessment. IPL expects that several of these sites will be subject to the final CCR rule, which is anticipated to be issued in December 2014.

At this time, CCR remain classified as exempt non-hazardous wastes under RCRA. IPL currently manages CCR to prevent harmful emissions or releases into the environment in accordance with state programs. IPL continues to use sound engineering practices for all CCRs that are beneficially used.

7.7 Environmental Regulatory and Related Initiatives

The following section describes IPL's significant on-going and emerging environmental regulatory initiatives. Section 7.7.1 discusses IPL's recent EPB filing for its coal-fired EGUs. At this time, IPL is not subject to any mandatory regulations to reduce GHG emissions, including CO_2, from existing EGUs. Therefore, IPL's ongoing consideration of potential GHG regulation risk is further discussed in Section 7.7.2 below. Section 7.7.3 discusses other related initiatives that also provide environmental benefits for IPL.

7.7.1 Emissions Plan and Budget (EPB)

IPL is responsible for developing and managing an EPB filing within the State of Iowa, consistent with the requirements of Iowa Code § 476.6(21). In accordance with this statute, each rate-regulated public utility that owns one or more electric generating facilities fueled by coal and located in the State of Iowa is required to file an EPB at least every two years. An EPB provides a utility's compliance plan and related budget to meet applicable federal and state environmental requirements. IUB approval demonstrates that IPL's EPB is expected to reasonably achieve cost-effective compliance with applicable environmental requirements.

On April 1, 2014, in IUB Docket No. EPB-2014-0150, IPL will file an updated EPB that addresses the 2015-2016 period, and provides IPL's understanding of current and emerging air, water and waste environmental compliance requirements that will impact IPL in the near future, as well as a discussion of how IPL will meet these requirements. IPL currently expects the IUB to issue a decision on IPL's EPB by the end of 2014. The complete filing will be available through the Electronic Filing System section of the IUB's website (http://www.iowa.gov/iub/).

Section I of IPL's EPB filing describes the specific emission compliance requirements for recently issued regulation and also emerging environmental rules considered in IPL's emission planning efforts. Section II of the EPB provides details of the ongoing compliance work and additional investments anticipated for future compliance given IPL's current understanding of potential environmental rule outcomes. More specifically, IPL's Budget Update in Section II provides the particular actions to be taken at IPL coal-fired generation facilities, related costs and timing for each action.

The EPB includes specific details of IPL's multi-emissions plan to be implemented during the 2015 to 2019 timeframe, including:

1) IPL's evaluation of emission control technologies and alternatives to achieve compliance with anticipated environmental requirements; and
2) IPL's specific activities and budgets for emissions reductions and other environmental compliance plans.

IPL's recent EPB includes environmental activities at regulated electric generating stations to reduce emissions of SO_2, NO_x, mercury and particulate matter. This includes completing the installation of air pollution controls to reduce SO_2 emissions at Lansing Unit 4 and toto reduce SO_2, Hg and PM emissions at Ottumwa Unit 1. In addition, a steam turbine and generator upgrade project will be completed at Ottumwa Unit 1 while efficiency upgrades at Lansing Unit 4 continue to be evaluated. IPL's [TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS] while M.L. Kapp Unit 2 will fuel switch to natural gas. The EPB also includes preliminary cost estimates for compliance with water and CCR regulations including studies, engineering evaluations and implementation of control measures.

IPL plans to continue to execute a long-term, staged environmental compliance strategy that incorporates current regulation and emerging environmental rules. IPL proactively manages the timing, cost and customer rate impact of the actions it undertakes in the implementation of this strategy. IPL will continue to monitor pending rules, as well as legal challenges that may result in final rules being vacated or stayed and remanded for further reconsideration. In addition to these uncertainties, IPL may not have control over the timing of its planned installation dates, due to the need to coordinate system-wide outages in order to maintain reliability. As necessary, IPL will maintain sufficient flexibility to ensure that environmental compliance requirements are met with sensitivity to minimize the resulting impact on customer rates.

Future updates to the IPL EPB will be performed at least every two years. IPL financial investments for environmental compliance activities discussed in the EPB filing are further updated based on known commitments for engineering, procurement and construction in disclosures to the Securities and Exchange Commission (SEC), Forms 10K and 10Q.

7.7.2 Potential Greenhouse Gas Regulation Risk

In April 2007, the U.S. Supreme Court concluded in *Massachusetts v. EPA* that GHGs meet the CAA definition of an air pollutant. In 2009, the EPA issued a finding that GHG emissions contribute to climate change, and therefore, threaten public health and welfare, also called the "Endangerment and Cause or Contribute Findings for GHGs". Taking effect in January 2010, this finding enabled the EPA to issue rules to report and regulate GHG emissions under the CAA. In response, the EPA has subsequently issued proposed and final regulations for GHGs under the CAA that are described in greater detail below.

Greenhouse Gas Reporting and Permitting

In October 2009, the final EPA Mandatory GHG Reporting rule was issued. The final rule does not require control of GHG emissions; rather, it requires that sources above certain threshold levels monitor and report emissions. The EPA anticipates that the data collected by this rule will improve the United States government's ability to formulate a set of climate change policy options. Emissions of GHGs are reported at the facility level in CO_2-equivalent (CO_2e) and include those facilities that emit 25,000 metric tons or more of CO_2e annually. The CO_2e is an aggregate measure used to compare total GHG impacts by taking into account the relative global warming potential (GWP) for each individual GHG and adding these contributions into a single value. The final rule applies to electric utility operations at IPL for GHG emissions of CO_2, CH_4, and N_2O from combustion of fossil fuels. Beginning with calendar year 2010, IPL has submitted annual emissions reports for ongoing compliance in accordance with the emissions monitoring methodologies and data collection procedures of the EPA's mandatory GHG reporting rule.

In June 2010, the EPA issued the GHG Tailoring Rule with these new permitting requirements commencing as of January 2, 2011. This rule established a GHG emissions threshold for major sources under the PSD permitting program of 100,000 tons per year (tpy) of CO_2e. The rule also established a threshold for what will be considered a significant increase in GHG emissions of 75,000 tpy for CO_2e. New major sources and significantly modified existing sources of GHGs are required to obtain PSD construction permits that demonstrate Best Available Control Technology (BACT) emissions measures to minimize GHGs. IPL is evaluating changes to GHGs resulting from various plant modifications and submitting PSD air permit applications on a project-specific basis. In February 2014, the U.S. Supreme Court heard oral arguments in Utility Air Regulatory Group v. EPA. This case represents an appeal of CRR v. EPA, in which the D.C. Circuit upheld EPA's suite of greenhouse gas regulations. The Supreme Court has granted review on the limited question of "[w]hether EPA permissibly determined that its regulation of greenhouse gas emissions from new motor vehicles triggered permitting requirements under the Clean Air Act for stationary sources that emit greenhouse gases." The Supreme Court ruling in this case is expected in 2014 and could have implications to the GHG Tailoring Rule.

EPA NSPS for GHG Emissions from Electric Utilities

In December 2010, under authority from the GHG Endangerment and Cause or Contribute Findings, the EPA announced the future issuance of GHG standards for electric utilities under the CAA. The GHG emission limits are to be established as New Source Performance Standards (NSPS) for new and existing fossil-fueled EGUs using authorities under CAA Section 111(b) and 111(d), respectively. Section 111 provides that NSPS are to "reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." This level of control is commonly referred to as best system of emission reduction (BSER).

Under Section 111(b), the new source requirements are generally established as numerical emissions limit, expressed as a performance level (i.e., a rate-based standard), based on emissions reductions achievable by current technologies applied on a unit or facility-specific basis. Whereas, states will have a more significant role in development and implementation of the existing source standards under Section 111(d), because the EPA's role is to issue the "emissions guidelines" that are used to develop state-specific plans to achieve the required reductions.

In June 2013, President Obama announced a Climate Action Plan that more broadly, reinforced the Administration's previously stated goal of reducing GHG emissions "in the range of 17% below 2005 levels by 2020." This plan includes various executive actions related to climate change initiatives, including:

- Cutting GHG emissions in the U.S. from various industrial sources, including power plants;
- Preparing the U.S. for the impacts of climate change through natural resource planning and infrastructure improvements; and,
- Leading international efforts to combat global climate change and prepare for its impacts.

As part of this announcement, a Presidential Memorandum was issued that directs the EPA to work expeditiously to complete the GHG reduction standards for CO_2 emissions from EGUs at power plants. More specifically, the Presidential Memorandum provided a revised schedule for these rulemakings as follows:

- New EGUs – Due to extensive public comments received on EPA's original proposal that was issued in March 2012, the EPA should repropose this standard by September 20, 2013 and finalize the reconsidered rule "in a timely fashion".
- Existing EGUs – EPA is to propose a rule by no later than June 1, 2014 and issue a final rule by no later than June 1, 2015 that will provide the guidelines that states must follow to achieve required GHG reductions for CO_2 emissions. State implementation plans

(SIPs) that provide details of how these guidelines are to be met will be required from state agencies by no later than June 30, 2016.

In September 2013, the EPA formally reproposed the NSPS for CO_2 emissions from new fossil-fueled power. The proposed rule would apply only to new fossil fuel-fired EGUs greater than 25 MW, which EPA would define to include utility boilers, integrated gasification combined cycle (IGCC) units and certain natural gas-fired stationary combustion turbines that generate electricity for sale. The proposed rule would not affect units that sell less than one-third of their potential electric output to the grid. EGUs at which ten percent or less of the heat input over a three-year period is derived from a fossil fuel would not be subject to any of the proposed NSPS.

The EPA is proposing to set separate standards for natural gas-fired stationary combustion turbines and for fossil fuel-fired utility boilers and IGCC units. The proposed emissions limits for natural gas turbines are based on the performance of modern natural gas combined cycle (NGCC) units. The EPA proposes a standard of 1,000 lb CO_2/MWh gross for large facilities greater than 850 MMBtu/hr heat input rating (this is approximately 100 MWe) and a standard of 1,100 lb CO_2/MWh gross for small facilities less than or equal to 850 MMBtu/hr heat input rating. The proposed standards would apply on a rolling 12-month average. The proposed limits for fossil fuel-fired utility boilers and IGCC units, including any new coal-fired EGUs, are based on the performance of a new efficient unit implementing partial carbon capture and storage (CCS). The EPA proposes a standard of 1,100 lb CO_2/MWh gross over a 12-operating month period. The EPA also is proposing an alternative seven-year compliance option (an 84-month rolling standard) with a standard between 1,000 and 1,050 lb CO_2/MWh.

The reproposed rule was published in the Federal Register on January 8, 2014 for public comment and there is no established date for the EPA to issue the final rulemaking. IPL's proposed plans for the Marshalltown Generating Station (MGS), an approximate 650 MW natural gas-fired combined cycle electric generating facility, includes the latest combustion turbine technology and will be designed to comply with the EPA's NSPS CO_2 emissions limit for new EGUs. Pending all regulatory approvals, the IPL expects to begin construction for MGS in 2014 and begin operations in 2017.

At this time, IPL does not have plans to build any new coal-fired EGUs that would be subject to this NSPS rule. In addition, the EPA has chosen not to propose standards as part of this rulemaking under CAA Section 111(b) to regulate CO_2 emissions from modified[3] or reconstructed[4] fossil-fueled EGUs at

[3] For purposes of NSPS, "modified" means a physical or operational change that increases the source's maximum achievable hourly rate of emissions, excluding pollution control projects.

[4] The regulations define "reconstructed" as existing sources that replace components to such an extent that the capital costs of the new components exceed 50% of the capital costs of an entirely new facility, and for which compliance with the NSPS is technologically and economically feasible.

this time. The EPA has stated that retrofit air pollution control system projects for regulations such as the Utility MATS are exempted under the proposed NSPS rule. The EPA has not provided any specific details on potential NSPS regulations for CO_2 from modified and reconstructed EGUs, but could issue a proposed rule in 2014, possibly coordinating this GHG action with the forthcoming NSPS for existing EGUs.

For existing EGUs, the NSPS proposed rule that is to be issued by the EPA in June 2014 under CAA Section 111(d) is expected to include emission guidelines that states must use to develop plans for EGU GHG reductions specifically including CO_2 emissions. Essentially, this emission guideline will reflect what is determined to be BSER for existing power plants and establishes the floor for states to develop their plans. The state plans explaining how the emission guidelines will be achieved are then submitted to the EPA for approval or disapproval.

The level of discretion allowed in providing for flexible standards and ability to broadly interpret application of the CAA under Section 111(d) for existing EGUs by both EPA and state agencies remains to be determined for this rulemaking. Consequently, this will have important implications in establishing the stringency of the standard, as well as, options and timeframe for achieving compliance. In particular, the rulemaking will impact:

- Whether the EPA's determination of BSER must be strictly applied to the regulated emission unit (in this case, an existing EGU) and if so, what level of sub-categorization would be considered in assessing the level of emissions reduction required for the standard (for example - differentiation by fuel types, boiler or turbine types, potential heat rate improvements or other factors);
- Whether BSER can be extended beyond the regulated EGU (i.e., beyond the power plant fenceline) by allowing for alternative compliance mechanisms, such as fleetwide emissions averaging or through a market-based emissions cap-and-trade program;
- Whether offsite emissions reductions can be considered, such as renewable energy resources or demand-side management programs for customer energy efficiency and conservation; and
- What baseline will be used from which to measure CO2 and possibly other GHG emissions reductions, as well as, the related monitoring, recordkeeping and reporting methodologies to verify these reductions.

The extent to which these factors could be applied for existing EGUs in the NSPS regulations remains unknown until the EPA's rule proposal is issued for public comment in 2014.

Lastly, under the CAA, both the EPA and state agencies have the ability to set less stringent standards or longer compliance schedules for existing sources when warranted, considering cost of control, remaining useful life of the facilities, location or process design at a particular facility, physical impossibility of installing necessary control equipment, or other factors making less stringent limits or longer compliance schedules appropriate.

The implications of the EPA's NSPS rule for GHG emissions from existing EGUs are highly uncertain, including the nature of required emissions controls and compliance timeline for mandating reductions of GHGs including CO_2 emissions. Furthermore, it is anticipated that legal challenges and litigation of the EPA's GHG rules will add to this uncertainty.

7.7.3 Environmentally Beneficial Related Initiatives

IPL recognizes the importance of providing reliable information and guidance regarding the costs, benefits and feasibility of installing an effective renewable system at a customer's premise. For that reason, to set realistic expectations, IPL will continue to offer environmentally-beneficial activities beyond those required for compliance with federal and state regulations, including:

- A dedicated Distributed Resources and Renewable Energy Hotline team (1-800-972-5325 or sellmypower@alliantenergy.com) to answer renewable energy and interconnection questions;
- Second Nature™, Alliant Energy's green-pricing program;
- General renewable information, including a custom renewable electric systems checklist, step-by-step interconnection guide and IPL technical guidelines for interconnection, at alliantenergy.com/sellmypower; and
- Links to more renewable information at the Database of State Incentives for Renewables & Efficiency (DSIRE) and Rural Energy for America Program (REAP) websites.

In addition, IPL will continue to maintain a number of environmentally-beneficial programs by maintaining the following compliance activities:

- Offer renewable tariffs such as IPL's Cogeneration and Small Power Producers (CSPP) and Community Based Energy Development (C-BED) tariffs that ensure the safety and the protection of customers;
- Provide standardized state-level interconnection application and agreement, at alliantenergy.com/sellmypower; and
- Encourage energy conservation through a variety of customer programs as part of IPL's 2013-2015 Electric and Natural Gas Conservation Improvement Program.

7.8 Other Actions

As in the past, IPL will continue to evaluate the service needs of its customers, the costs of various resources, the applicability of new technologies, and other factors related to resource planning. IPL expects its plan to be adequately flexible so as to accommodate future uncertainties.

IPL Renewable Status

	Retail and Wholesale Energy by State (Note 1)				Retail and Wholesale Demand by State (Note 1)			
Year	MN MWH Retail Sales	IA MWH Retail Sales	MN MWH Wholesale Sales	IA/IL MWH Wholesale Sales	MN MW Retail Demand	IA MW Retail Demand	MN MW Wholesale Demand	IA/IL MW Wholesale Demand
2012								
2013	(final numbers for 2013 not in yet)				(final numbers for 2013 not in yet)			
2014	843,247	14,586,528	843	489,462	175.7	2,562.8	0.1	80.8
2015	841,904	14,774,484	842	492,888	177.4	2,588.1	0.2	81.6
2016	841,126	14,921,185	843	496,338	179.0	2,610.6	0.2	82.4
2017	839,968	15,063,747	842	499,812	180.5	2,632.4	0.2	83.0
2018	839,152	15,208,606	843	503,311	182.0	2,654.6	0.2	83.7
2019	845,987	15,332,504	850	507,411	183.4	2,674.7	0.2	84.4
2020	853,453	15,467,692	851	511,885	184.9	2,696.8	0.2	85.1
2021	860,983	15,604,025	851	516,397	186.4	2,719.1	0.2	85.8
2022	868,589	15,741,729	851	520,954	188.0	2,741.6	0.2	86.5
2023	876,275	15,880,904	851	525,560	189.6	2,765.9	0.2	87.3
2024	884,030	16,021,309	851	530,207	191.3	2,790.4	0.2	88.0
2025	891,854	16,162,956	851	534,894	193.0	2,815.1	0.2	88.8
2026	899,746	16,305,855	851	539,623	194.7	2,840.0	0.2	89.6
2027	907,708	16,450,018	851	544,394	196.4	2,865.2	0.2	90.4
2028	915,741	16,595,455	851	549,207	198.2	2,890.6	0.2	91.2
2029	923,845	16,742,178	851	554,063	199.9	2,916.1	0.2	92.0

(Note 1) forecast as of October 2013

IPL Renewable Status

	REC Share Percentages For Sources Other Than Whispering Willow					
Year	MN MWH Retail Sales with 3.15% Distribution Energy Losses (Note 2)	IA/IL MWH Retail Sales with 3.15% Distribution Energy Losses (Note 2)	MWH Wholesale Sales	MN Retail REC Share Ratio (other than Whispering Willow)	IA Retail REC Share Ratio (other than Whispering Willow)	Wholesale REC Share Ratio (other than Whispering Willow)
2012				(assume 2013 ratios similar to 2014)		
2013	(final numbers for 2013 not in yet)			5.3%	91.7%	3.0%
2014	870,673	15,060,948	490,305	5.3%	91.7%	3.0%
2015	869,287	15,255,017	493,730	5.2%	91.8%	3.0%
2016	868,483	15,406,490	497,181	5.2%	91.9%	3.0%
2017	867,288	15,553,689	500,655	5.1%	91.9%	3.0%
2018	866,445	15,703,259	504,154	5.1%	92.0%	3.0%
2019	873,502	15,831,186	508,262	5.1%	92.0%	3.0%
2020	881,211	15,970,771	512,736	5.1%	92.0%	3.0%
2021	888,986	16,111,538	517,248	5.1%	92.0%	3.0%
2022	896,839	16,253,721	521,805	5.1%	92.0%	3.0%
2023	904,776	16,397,422	526,411	5.1%	92.0%	3.0%
2024	912,783	16,542,394	531,057	5.1%	92.0%	3.0%
2025	920,861	16,688,648	535,745	5.1%	92.0%	3.0%
2026	929,010	16,836,195	540,474	5.1%	92.0%	3.0%
2027	937,231	16,985,047	545,245	5.1%	92.0%	3.0%
2028	945,525	17,135,214	550,058	5.1%	92.0%	3.0%
2029	953,892	17,286,709	554,914	5.1%	92.0%	3.0%

(Note 2) REC Share Ratios adjust for 3.15% reasonable distribution energy losses to put Retail and Wholesale load at equivalent electric system level. Without adjustment, Retail Sales are generally at secondary and distribution level, Wholesale Sales generally at distribution and transmission level.

IPL Renewable Status

	REC Share Percentages For Whispering Willow (Note 3)					
Year	MN MW Retail Demand with 4.01% Distribution Demand Losses (Note 4)	IA MW Retail Demand with 4.01% Distribution Demand Losses (Note 4)	MW Wholesale Demand	MN Retail REC Share Ratio (Whispering Willow)	IA Retail REC Share Ratio (Whispering Willow)	Wholesale REC Share Ratio (Whispering Willow)
2012				(assume 2013 ratios similar to 2014)		
2013	(final numbers for 2013 not in yet)			6.2%	91.0%	2.8%
2014	183	2,670	81	6.2%	91.0%	2.8%
2015	185	2,696	82	6.2%	91.0%	2.8%
2016	186	2,720	83	6.2%	91.0%	2.8%
2017	188	2,742	83	6.2%	91.0%	2.8%
2018	190	2,765	84	6.2%	91.0%	2.8%
2019	191	2,786	85	6.2%	91.0%	2.8%
2020	193	2,809	85	6.2%	91.0%	2.8%
2021	194	2,833	86	6.2%	91.0%	2.8%
2022	196	2,856	87	6.2%	91.0%	2.8%
2023	198	2,881	87	6.2%	91.0%	2.8%
2024	199	2,907	88	6.2%	91.0%	2.8%
2025	201	2,933	89	6.2%	91.0%	2.8%
2026	203	2,959	90	6.2%	91.0%	2.8%
2027	205	2,985	91	6.2%	91.0%	2.8%
2028	206	3,011	91	6.2%	91.0%	2.8%
2029	208	3,038	92	6.2%	91.0%	2.8%

(Note 3) Whispering Willow costs, and RECs, are proposed to be allocated by coincident peak.

(Note 4) REC Share Ratios adjust for 4.01% reasonable distribution demand losses to put Retail and Wholesale load at equivalent electric system level. Without adjustment, Retail Sales are generally at secondary and distribution level, Wholesale Sales generally at distribution and transmission level.

IPL Renewable Status

	REC Shares Other than Whispering Willow				REC Shares for Whispering Willow				Total REC Shares			
Year	IPL Renewable MWH (RECs)	MN Retail REC Share	IA Retail REC Share	Wholesale REC Share	IPL Renewable MWH (RECs)	MN Retail REC Share	IA Retail REC Share	Wholesale REC Share	IPL Renewable MWH (RECs)	MN Retail REC Share	IA Retail REC Share	Wholesale REC Share
2012	(assume ratios similar to 2014)				(assume ratios similar to 2014)				(assume ratios similar to 2014)			
2013	740,106	39,240	678,769	22,097	639,069	39,868	581,558	17,643	1,379,175	79,108	1,260,327	39,740
2014	702,342	37,237	644,135	20,970	662,000	41,299	602,425	18,276	1,364,342	78,536	1,246,561	39,245
2015	702,073	36,725	644,489	20,859	662,000	41,299	602,425	18,276	1,364,073	78,024	1,246,914	39,135
2016	697,801	36,133	640,983	20,685	662,000	41,299	602,425	18,276	1,359,801	77,432	1,243,409	38,961
2017	683,027	35,007	627,811	20,208	662,000	41,299	602,425	18,276	1,345,027	76,306	1,230,236	38,484
2018	674,849	34,246	620,676	19,927	662,000	41,299	602,425	18,276	1,336,849	75,545	1,223,101	38,202
2019	658,919	33,438	606,025	19,456	662,000	41,299	602,425	18,276	1,320,919	74,737	1,208,450	37,732
2020	611,286	31,021	562,216	18,050	662,000	41,299	602,425	18,276	1,273,286	72,320	1,164,641	36,325
2021	608,101	30,860	559,285	17,955	662,000	41,299	602,425	18,276	1,270,101	72,159	1,161,711	36,231
2022	573,212	29,089	527,198	16,925	662,000	41,299	602,425	18,276	1,235,212	70,388	1,129,623	35,201
2023	572,921	29,075	526,929	16,916	662,000	41,299	602,425	18,276	1,234,921	70,374	1,129,355	35,192
2024	526,593	26,724	484,321	15,548	662,000	41,299	602,425	18,276	1,188,593	68,023	1,086,746	33,824
2025	481,929	24,458	443,242	14,229	662,000	41,299	602,425	18,276	1,143,929	65,756	1,045,667	32,505
2026	481,628	24,443	442,966	14,220	662,000	41,299	602,425	18,276	1,143,628	65,741	1,045,391	32,496
2027	453,325	23,006	416,935	13,384	662,000	41,299	602,425	18,276	1,115,325	64,305	1,019,360	31,660
2028	272,296	13,819	250,438	8,039	662,000	41,299	602,425	18,276	934,296	55,118	852,863	26,315
2029	(45,713)	(2,320)	(42,044)	(1,350)	662,000	41,299	602,425	18,276	616,287	38,979	560,382	16,926
	2013 supply estimated, final numbers not yet in. 2013 demand and energy values by state/customer class not yet in. Assume 2013 allocation rates similar to 2014.				2013 supply estimated, final numbers not yet in. 2013 demand and energy values by state/customer class not yet in. Assume 2013 allocation rates similar to 2014.				2013 supply estimated, final numbers not yet in. 2013 demand and energy values by state/customer class not yet in. Assume 2013 allocation rates similar to 2014.			

IPL Renewable Status

	Minnesota Status					Minnesota 4 Year Shelf Life Calculations			
Year	MN % Requirement of retail sales	MN REC Requirement for retail sales	MN Retail REC Share	MN RECs as % of Retail Sales	MN REC Status before 4 Year Shelf Life	4 Year Shelf Life REC balance BOY	4 Year Shelf Life REC balance EOY	REC **req'ts unmet**	4 Year Shelf Life REC's **"Lost"**
2012		(this represents 2012 banked RECs)			37,711	0	37,711	0	0
2013	12%	101,190	79,108	9.5%	(22,082)	37,711	15,629	0	0
2014	12%	101,190	78,536	9.3%	(22,653)	15,629	0	-7,024	0
2015	12%	101,029	78,024	9.3%	(23,004)	0	0	-23,004	0
2016	17%	142,991	77,432	9.2%	(65,560)	0	0	-65,560	0
2017	17%	142,795	76,306	9.1%	(66,488)	0	0	-66,488	0
2018	17%	142,656	75,545	9.0%	(67,110)	0	0	-67,110	0
2019	17%	143,818	74,737	8.8%	(69,081)	0	0	-69,081	0
2020	20%	170,691	72,320	8.5%	(98,371)	0	0	-98,371	0
2021	20%	172,197	72,159	8.4%	(100,038)	0	0	-100,038	0
2022	20%	173,718	70,388	8.1%	(103,329)	0	0	-103,329	0
2023	20%	175,255	70,374	8.0%	(104,881)	0	0	-104,881	0
2024	20%	176,806	68,023	7.7%	(108,783)	0	0	-108,783	0
2025	25%	222,963	65,756	7.4%	(157,207)	0	0	-157,207	0
2026	25%	224,937	65,741	7.3%	(159,195)	0	0	-159,195	0
2027	25%	226,927	64,305	7.1%	(162,622)	0	0	-162,622	0
2028	25%	228,935	55,118	6.0%	(173,817)	0	0	-173,817	0
2029	25%	230,961	38,979	4.2%	(191,982)	0	0	-191,982	0

2013 supply estimated, final numbers not yet in.
2013 demand and energy values by state/customer class not yet in.
Assume 2013 allocation rates similar to 2014.
Assume 2013 requirements similar to 2014. (Also similar to 2012)

IPL Renewable Status

	Iowa Status				
Year	IA % Requirement of retail sales (Note 5)	IA REC Requirement for retail sales	IA Retail REC Share	IA RECs as % of Retail Sales	IA REC Status before 4 Year Shelf Life
2012					
2013	0.8%	117,833	1,260,327	8.7%	1,142,494
2014	0.8%	117,833	1,246,561	8.5%	1,128,728
2015	0.8%	117,833	1,246,914	8.4%	1,129,081
2016	0.8%	117,833	1,243,409	8.3%	1,125,576
2017	0.8%	117,833	1,230,236	8.2%	1,112,403
2018	0.8%	117,833	1,223,101	8.0%	1,105,268
2019	0.8%	117,833	1,208,450	7.9%	1,090,617
2020	0.8%	117,833	1,164,641	7.5%	1,046,808
2021	0.8%	117,833	1,161,711	7.4%	1,043,878
2022	0.7%	117,833	1,129,623	7.2%	1,011,790
2023	0.7%	117,833	1,129,355	7.1%	1,011,522
2024	0.7%	117,833	1,086,746	6.8%	968,913
2025	0.7%	117,833	1,045,667	6.5%	927,834
2026	0.7%	117,833	1,045,391	6.4%	927,558
2027	0.7%	117,833	1,019,360	6.2%	901,527
2028	0.7%	117,833	852,863	5.1%	735,030
2029	0.7%	117,833	560,382	3.3%	442,549

(Note 5) IPL forecasted requirements based on 199 IAC 15.11(1) = 49.8 MW of capacity. IPL has identified this capacity as 65.1% of the 76.5 MW Buena Vista/Storm Lake Power Partners Wind Farm.

2013 supply estimated, final numbers not yet in.
2013 demand and energy values by state/customer class not yet in.
Assume 2013 allocation rates similar to 2014.

IPL Renewable Production in MWH/year

	Buena Vista Wind Farm [4]	Cerro Gordo Wind Farm [5]	Flying Cloud Wind Farm	Hancock Wind Farm	Hancock Second Nature Use	Hancock Sale to CIPCO	Neppel Wind Farm	Hardin Hilltop / Wind[2]	America's Hydro[8]	Sibley Hills
in M-RETS	Yes	Yes	Yes	Yes	-	-	Yes	Yes	No	No
state of location	IA	IA	IA	IA	IA	IA	IA	IA	IA	IA
nameplate MW	76.5	41.3	43.5	56.8	n/a	-2 (3.52%)	1.5	14.7	2.69	1.2
PPA vs owned	PPA	PPA	PPA	PPA	-	-	PPA	PPA	PPA	PPA
renewable type	wind	wind	wind	wind	wind	wind	wind	wind	hydro	wind
2013	194,040	89,818	143,173	146,252	-31,218	-5,148	4,802	49,183	8,000	1,954
2014	177,300	88,400	140,400	141,400	-35,350	-4,977	4,500	44,300	8,000	2,000
2015	177,300	88,400	140,400	141,400	-35,350	-4,977	4,500	44,300	8,000	2,000
2016	177,300	88,400	140,400	141,400	-35,350	-4,977	4,500	44,300	4,000	2,000
2017	177,300	88,400	140,400	141,400	-35,350	-4,977	4,500	44,300		2,000
2018	177,300	88,400	140,400	141,400	-35,350	-4,977	4,500	44,300		2,000
2019	177,300	88,400	140,400	141,400	-35,350	-4,977	2,250	44,300		2,000
2020	177,300	88,400	140,400	141,400	-35,350	-4,977		44,300		2,000
2021	177,300	88,400	140,400	141,400	-35,350	-4,977		44,300		2,000
2022	177,300	88,400	140,400	141,400	-35,350	-4,977		44,300		2,000
2023	177,300	88,400	140,400	141,400	-35,350	-4,977		44,300		2,000
2024	177,300	44,200	140,400	141,400	-35,350	-4,977		44,300		167
2025	177,300		140,400	141,400	-35,350	-4,977		44,300		
2026	177,300		140,400	141,400	-35,350	-4,977		44,300		
2027	177,300		140,400	141,400	-35,350	-4,977		44,300		
2028	177,300		140,400		-35,350					
2029					-35,350					

Notes:

1) Not yet built
2) Hardin Hilltop/Wind collection of CyHawk, Greene, Hardin, Poverty Ridge, Sutton, Wind Family, and Zontos
3) Allendorf (Sibley) aka NAE Allendorf LLC aka Navitas Energy Inc
4) Buena Vista aka Storm Lake Power Partners
5) Cerro Gordo aka Hawkeye Power Partners
6) Adams Wind Farm collection of G McNeilus, NcNeilus Windfarm LLC, and GARMAR Wind
7) Windom Wind Farm aka Bingham
8) America's Hydro collection of Maquoketa, Anamosa, and Iowa Falls Hydro

IPL Renewable Production in MWH/year

	Whispering Willow Wind Farm	Minn Wind I (Beaver Creek)	Minn Wind II (Beaver Creek)	Sieve Wind Farm	Ag Land Energy 1 and 3	Ag Land Energy 2	Ag Land Energy 5 & 6	Junction Hilltop Wind	Kirkwood Commnty College Wind Turbine	Arnold Wind	Wilmont Hills
in M-RETS	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
state of location	IA	MN	MN	MN	IA	IA	IA	IA	IA	MN	MN
nameplate MW	200	3.8		1	3.2	1.6	3.2	8	2.5	1.65	1.5
PPA vs owned	owned	PPA	PPA	PPA	PPA	PPA	PPA	PPA	PPA	PPA	PPA
renewable type	wind	wind	wind	wind	wind	wind	wind	wind	wind	wind	wind
2013	639,069	4,897	4,897	2,842	12,311	5,787	11,775	30,505	5,001	6,114	4,196
2014	662,000	5,100	4,900	2,900	11,200	5,600	11,200	28,000	6,600	5,800	5,500
2015	662,000	5,100	4,900	2,900	11,200	5,600	11,200	28,000	6,600	5,800	5,500
2016	662,000	5,100	4,900	2,900	11,200	5,600	11,200	28,000	6,600	5,800	5,500
2017	662,000	2,550	2,450	2,900	11,200	5,600	11,200	28,000	6,600	5,800	
2018	662,000				11,200	5,600	11,200	28,000	6,600	5,800	
2019	662,000				11,200	5,600	11,200	28,000	6,600	5,800	
2020	662,000				11,200	5,600	11,200	28,000	6,600	2,900	
2021	662,000				11,200	5,600	11,200	28,000	6,600		
2022	662,000							28,000			
2023	662,000							28,000			
2024	662,000							28,000			
2025	662,000							28,000			
2026	662,000							28,000			
2027	662,000										
2028	662,000										
2029	662,000										

Notes:
1) Not yet built
2) Hardin Hilltop/Wind collection of CyHawk, Greene, Hardin, Poverty Ridge, Sutton, Wind Family, and Zontos
3) Allendorf (Sibley) aka NAE Allendorf LLC aka Navitas Energy Inc
4) Buena Vista aka Storm Lake Power Partners
5) Cerro Gordo aka Hawkeye Power Partners
6) Adams Wind Farm collection of G McNeilus, NcNeilus Windfarm LLC, and GARMAR Wind
7) Windom Wind Farm aka Bingham
8) America's Hydro collection of Maquoketa, Anamosa, and Iowa Falls Hydro

IPL Renewable Production in MWH/year

	Wilmont Hills Second Nature Use	Adams Wind Farm[6]	Windom Wind Farm[7]	Additional Second Nature Use	Total MWH Other than Whispering Willow	Whispering Willow MWH	Total MWH With Whispering Willow
in M-RETS	-	Yes	Yes				
state of location	MN	MN	MN				
nameplate MW	n/a	6	15				
PPA vs owned	-	PPA	PPA	PPA			
renewable type	wind	wind	wind				
2013	-4,196	12,485	42,901	-264	740,106	639,069	1,379,175
2014	-5,500	13,400	42,200	-530	702,342	662,000	1,364,342
2015	-5,500	13,400	42,200	-800	702,073	662,000	1,364,073
2016	-5,500	13,400	42,200	-1,071	697,801	662,000	1,359,801
2017	-5,500	13,400	42,200	-1,346	683,027	662,000	1,345,027
2018	-5,500	13,400	42,200	-1,623	674,849	662,000	1,336,849
2019	-5,500		42,200	-1,903	658,919	662,000	1,320,919
2020	-5,500			-2,186	611,286	662,000	1,273,286
2021	-5,500			-2,472	608,101	662,000	1,270,101
2022	-5,500			-2,761	573,212	662,000	1,235,212
2023	-5,500			-3,052	572,921	662,000	1,234,921
2024	-5,500			-3,347	526,593	662,000	1,188,593
2025	-5,500			-3,644	481,929	662,000	1,143,929
2026	-5,500			-3,944	481,628	662,000	1,143,628
2027	-5,500			-4,248	453,325	662,000	1,115,325
2028	-5,500			-4,554	272,296	662,000	934,296
2029	-5,500			-4,863	-45,713	662,000	616,287

Notes:
1) Not yet built
2) Hardin Hilltop/Wind collection of CyHawk, Greene, Hardin, Poverty Ridge, Sutton, Wind Family, and Zontos
3) Allendorf (Sibley) aka NAE Allendorf LLC aka Navitas Energy Inc
4) Buena Vista aka Storm Lake Power Partners
5) Cerro Gordo aka Hawkeye Power Partners
6) Adams Wind Farm collection of G McNeilus, NcNeilus Windfarm LLC, and GARMAR Wind
7) Windom Wind Farm aka Bingham
8) America's Hydro collection of Maquoketa, Anamosa, and Iowa Falls Hydro

Interstate Power and Light Company
An Alliant Energy Company

Alliant Tower
200 First Street SE
P.O. Box 351
Cedar Rapids, IA 52406-0351

Office: 1.800.822.4348
www.alliantenergy.com

Alliant Energy Corporate Service
Legal Department
319.786.4505 – Phone
3193786.4533 – Fax

Paula N. Johnson
Senior Attorney - Regulatory

December 17, 2013

Dr. Burl W. Haar, Executive Secretary
Minnesota Public Utilities Commission
121 Seventh Place East, Suite 350
St. Paul, MN 55101-2147

RE: Interstate Power and Light Company
Docket No. E001/M-05-1883
Community-Based Energy Development (C-BED) Annual Report

Dear Dr. Haar:

Enclosed for e-Filing with the Minnesota Public Utilities Commission, please find Interstate Power and Light Company's (IPL) Community-Based Energy Development (C-BED) Annual Report pursuant to the Commission's July 28, 2006 Order in Docket No. E001/M-05-1883.

Copies of this filing have been served on the Minnesota Department of Commerce, Division of Energy Resources, the Minnesota Office of Attorney General – Residential and Small Business Utilities Division and the attached service list.

Respectfully submitted,

/s/ Paula N. Johnson
Paula N. Johnson
Senior Attorney - Regulatory

PNJ/tao
Enclosures

cc: Service List

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	**Chair**
David C. Boyd	**Commissioner**
Nancy Lange	**Commissioner**
J. Dennis O'Brien	**Commissioner**
Betsy Wergin	**Commissioner**

IN THE MATTER OF INTERSTATE POWER AND LIGHT COMPANY'S PETITION FOR APPROVAL OF A COMMUNITY-BASED ENERGY DEVELOPMENT (C-BED) TARIFF	**DOCKET NO. E001/M-05-1883**

AFFIDAVIT OF SERVICE

STATE OF IOWA)
) ss.
COUNTY OF LINN)

Tonya A. O'Rourke, being first duly sworn on oath, deposes and states:

That on the 17th day of December, 2013, copies of the foregoing Affidavit of Service, together with Interstate Power and Light Company's Community-Based Energy Development (C-BED) Annual Report, were served upon the parties on the attached service list, by e-filing, overnight delivery, electronic mail, and/or first-class mail, proper postage prepaid from Cedar Rapids, Iowa.

__*/s/ Tonya A. O'Rourke*______
Tonya A. O'Rourke

Subscribed and Sworn to Before Me
this 17th day of December, 2013.

___*/s/ Kathleen J. Faine*______________
Kathleen J. Faine
Notary Public
My Commission Expires on February 20, 2015

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Julia	Anderson	Julia.Anderson@ag.state.mn.us	Office of the Attorney General-DOC	1800 BRM Tower 445 Minnesota St St. Paul, MN 551012134	Electronic Service	No	OFF_SL_5-1883_1
Lisa	Daniels	lisadaniels@windustry.org	Windustry	201 Ridgewood Avenue Minneapolis, MN 55403	Paper Service	No	OFF_SL_5-1883_1
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 500 Saint Paul, MN 551012198	Electronic Service	Yes	OFF_SL_5-1883_1
Burl W.	Haar	burl.haar@state.mn.us	Public Utilities Commission	Suite 350 121 7th Place East St. Paul, MN 551012147	Electronic Service	Yes	OFF_SL_5-1883_1
John	Lindell	agorud.ecf@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012130	Electronic Service	No	OFF_SL_5-1883_1
Mark	Lindquist	N/A	The Minnesota Project	57107 422nd St New Ulm, MN 56073-4321	Paper Service	No	OFF_SL_5-1883_1
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_5-1883_1
Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD	Suite 325 7301 Ohms Lane Edina, MN 55439	Electronic Service	No	OFF_SL_5-1883_1
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	OFF_SL_5-1883_1

STATE OF MINNESOTA

BEFORE THE MINNESOTA PUBLIC UTILITIES COMMISSION

Beverly Jones Heydinger	**Chair**
David C. Boyd	**Commissioner**
Nancy Lange	**Commissioner**
J. Dennis O'Brien	**Commissioner**
Betsy Wergin	**Commissioner**

IN THE MATTER OF INTERSTATE POWER AND LIGHT COMPANY'S PETITION FOR APPROVAL OF A COMMUNITY-BASED ENERGY DEVELOPMENT (C-BED) TARIFF	**DOCKET NO. E001/M-05-1883**

INTERSTATE POWER AND LIGHT COMPANY'S C-BED ANNUAL REPORT

COMES NOW, Interstate Power and Light Company (IPL or the Company), and pursuant to the Minnesota Public Utilities Commission's (Commission) Order dated July 28, 2006, files its Community-Based Energy Development Tariff (C-BED Tariff) Annual Report. In support of its annual report, IPL states the following:

1. On December 1, 2005, IPL petitioned the Commission for approval of its proposed C-BED tariff. The Minnesota Department of Commerce (Department), Windustry, the Minnesota Project, Institute for Self-Reliance, and Minnesotans for Energy Efficient Economy (Joint Commentators) filed reply comments on February 2, 2006. IPL and the Joint Commentators filed reply comments on February 21, 2006, and the Department filed supplemental comments on March 29, 2006. On June 7, 2006, IPL responded to the reply comments.

2. On July 28, 2008, the Commission approved IPL's C-BED tariff with modifications. On November 12, 2007, IPL petitioned the Commission to modify its current C-BED tariff (Docket No. E001/M-07-1431) to incorporate the changes from the Next Generation Energy Act of 2007, Article 4, C-BED and Related Issues, approved May 25, 2007. The Commission issued an order approving the tariff, effective the date of its order, on September 5, 2008.

3. In its September 5, 2008, order in Docket No. E001/M-07-1431, the Commission also ordered IPL to file an annual report, either as part of its biennial resource plan or separately. IPL is filing this annual report separate from its biennial resource plan.

4. Since its C-BED tariff was approved, IPL has not received any proposals pursuant to its C-BED tariff. As such, IPL has not rejected any proposals made pursuant to its C-BED tariff. Additionally, IPL has not adopted service for any C-BED proposal under an alternative IPL tariff. Since IPL has not received any proposals, it has not executed any contracts under its C-BED tariff.

5. IPL has developed C-BED materials to educate IPL's account management team in Minnesota on the details of the C-BED tariff and to educate C-BED qualified IPL customers in Minnesota on the details of the C-BED tariff. IPL's Key Account Management team uses these collateral materials to discuss the C-BED tariff with potential C-BED candidates. IPL also educates customers on the C-BED tariff and other Minnesota customer-owned generation options at www.alliantenergy.com/sellmypower. Additionally, customers can call the Alliant Energy Distributed Resources and Renewable Energy Hotline at 1-800-972-5325

to learn more about distributed generation, the interconnection process, fees and tariffs.

WHEREFORE, IPL respectfully requests the Minnesota Public Utilities Commission accept IPL's Annual Report on C-BED projects as in compliance with the Commission's July 28, 2006 Order.

Dated this 17th day of December, 2013.

Respectfully submitted,

INTERSTATE POWER AND LIGHT COMPANY

By *_/s/ Paula N. Johnson___*

Paula N. Johnson
Senior Attorney - Regulatory
Alliant Energy Corporate Services, Inc.
200 First Street S.E.
P.O. Box 351
Cedar Rapids, IA 52406-0351
(319) 786-4219

PUBLIC INTEREST CONSIDERATIONS

IPL's 2014 IRP presents a framework for future actions that IPL will take to provide reliable, reasonable-cost service with manageable risks for its customers. Development of the 2014 IRP involved balanced consideration of cost, risk, uncertainty, supply reliability, and long run public policy goals. The process and action plan of the IRP meet Minnesota state IRP standards and guidelines.

8.0 Overall Factors

This Resource Plan balances the concerns of many interested parties. A primary concern of IPL is meeting the future energy needs of its customers. These needs are to be met safely, reliably, responsibly, efficiently and flexibly. Numerous factors impact the decisions for which specific resources and/or combinations of resources are selected and these are discussed throughout prior sections of this report. IPL remains flexible when considering all aspects of resource planning.

8.0.1 Reliably Meeting Customers' Needs

As a participant of MISO and under the Resource Adequacy (Module E) provisions of the MISO Tariff, IPL has agreed to provide capacity to serve its own load and a reserve capacity obligation. Controls exist to ensure that each participant provides their share of allocated reserves. Currently, IPL's system meets the MISO requirements and calculations show that it will do so in the future with additional action taken per the Resource Plan. A MISO minimum planning reserve margin of 7.3% above MISO coincident peak is maintained throughout the 15 year study period to ensure reliable service. An important input to these reserve calculations is the system forecast, which projects the demand and energy for the future. The load forecast is reviewed at least annually to stay current with customers' needs. Section 2 provides a comprehensive discussion of the load forecast.

8.0.2 Responsibly Meeting Customers' Needs

IPL is diligent in using resources wisely, which requires balancing financial impacts with socioeconomic and environmental effects. The actions of IPL relative to these issues are consistent with its institutional responsibilities. Generally, demand-side alternatives reduce emissions into the air, water and land by reducing fossil-fueled supply-side generation. IPL includes DSM throughout the 15 year study period in its proposed plan. Furthermore, renewable resources, such as wind generation, also reduce emissions. IPL currently has both owned and purchased wind resources totaling approximately 450 MWs of nameplate generation in its proposed plan. IPL's proposed plan demonstrates IPL is committed to balancing socioeconomic, environmental, and financial impacts through planning and operational discipline. In fact, as shown in the charts below, IPL's projected annual CO_2 output (tons) in its No Carbon and Minnesota Midpoint 2017 Carbon Reference Cases noticeably decline over the study period. This is in contrast to IPL's energy growth. Therefore, IPL's projected CO_2 ton/MWh rate also declines over the study period.

Figure 8.0.2.1 – No Carbon Reference Case, CO2 Emissions and Rate

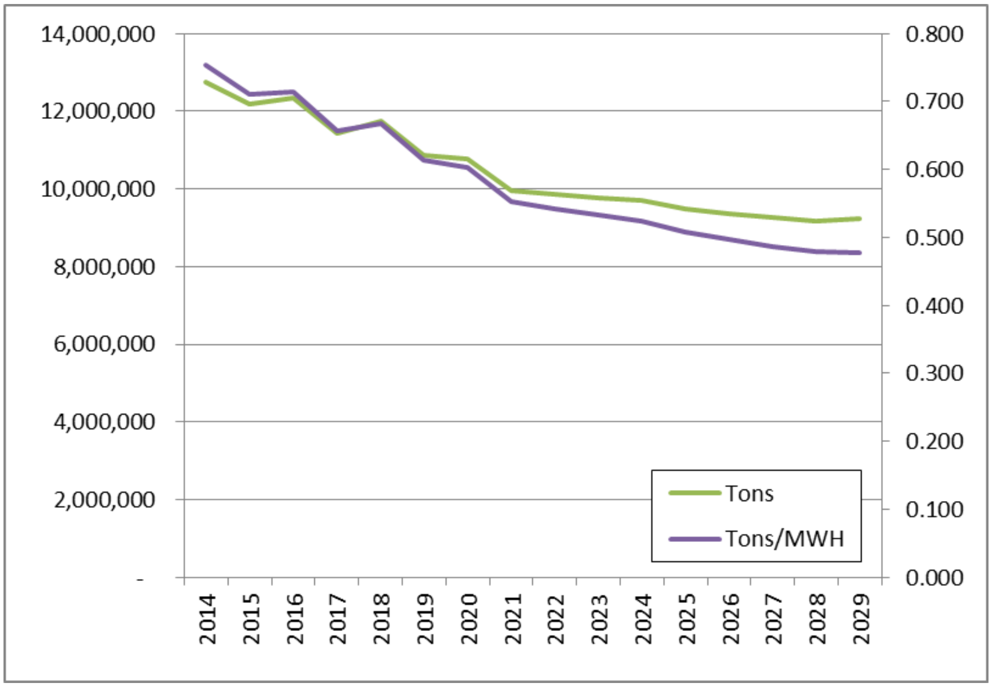
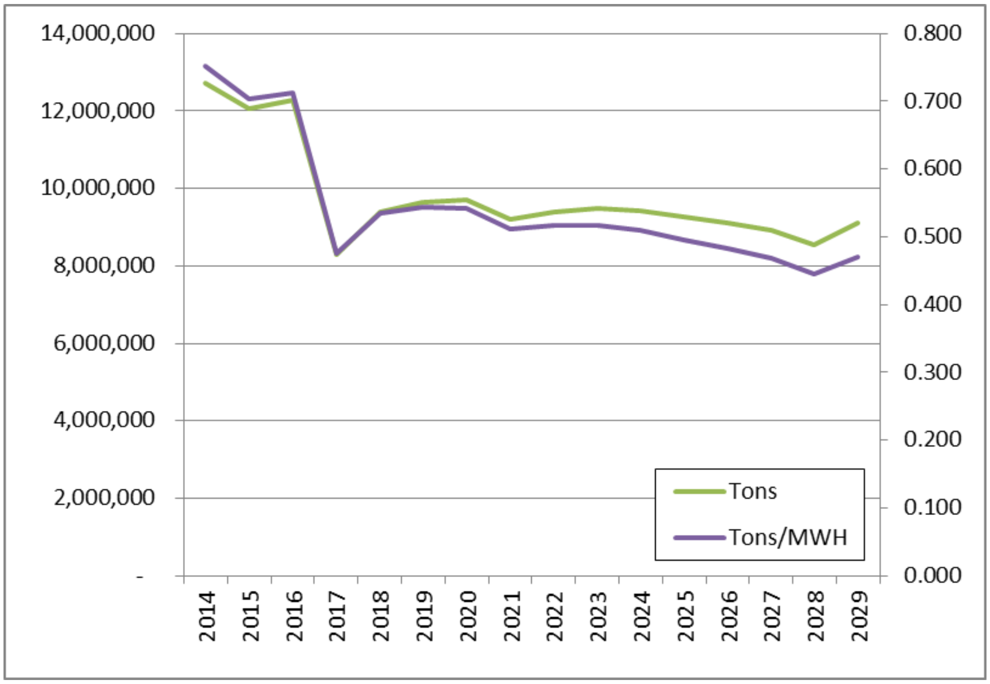


Figure 8.0.2.2 – Minnesota Midpoint 2017 Carbon Reference Case, CO2 Emissions and Rate



8.0.3 Efficiently Meeting Customers' Needs

IPL develops resource plans based on minimizing the cumulative present worth of revenue requirements, given regulatory and other constraints, yielding a reasonable plan. All reasonable resource alternatives (demand-side and supply-side) are modeled, evaluated and optimized using EGEAS. This ensures a reasonable plan and, as a result, customers' rates will be as low as practicable.

The EGEAS results indicate that IPL's total supply-related costs (fuel, operations & maintenance, and new capital fixed charges) per kWh will increase nominally over the study period at an average rate of about:

- 4.5 percent per year period for the No Carbon scenario; and
- 5.8 percent per year for the Minnesota Midpoint 2017 Carbon scenario.

Assuming an inflation rate of approximately 2 percent per year over that same time period, the change in real terms is approximately:

- 2.4 percent per year for the No Carbon scenario, and,
- 3.7 percent per year for the Minnesota Midpoint 2017 Carbon scenario.

As a reasonable cost electricity manufacturer, IPL will continue to provide reliable, responsible and affordable electric energy to its customers.

8.0.4 Flexibly Meeting Customers' Needs

The Action Plan in Section 7 shows that IPL is continually engaged in planning, and can reasonably respond to unanticipated events. The activities previously discussed, and their scheduling, permit the timely determination of possible changes to this Resource Plan. This flexibility ensures that customers' needs will be met with no unreasonable increase in costs due to unforeseen changes. Unexpected changes in regulations, customer loads, costs, technology and other parameters can all be accommodated. IPL is not committed to the cost, type, size or timing of any new resources with lead times that allow for further evaluation – this plan is responsive to changes in the load forecast and changes in resource characteristics.

8.1 Specific Factors

In addition to those topics discussed above, IPL studied some specific assumptions and their impacts on the Resource Plan. The scenarios and sensitivities that were developed and a detailed discussion of each are given in Section 6.

8.2 Considerations of the Proposed Plan

The evaluation of the proposed plan, detailed throughout this document, indicates that the proposed plan is in the public interest. This Resource Plan was developed using the efforts of many company employees and incorporated written reports of several other national consulting firms. The result is a plan that attempted to be responsive to the concerns of all.

8.3 Minnesota Greenhouse Gas Reduction Goals

The Minnesota greenhouse gas reductions goals from Minn. Stat. § 216H.02 are sector-wide reductions of 15 percent below 2005 levels by 2015, and 30 percent below 2005 levels by 2025. IPL's 2014 Resource Plan supports these goals with declining system CO_2 emissions and emission rates. Table 8.3.1 below illustrates projected CO_2 emissions reductions from 2005 values.

Table 8.3.1 – No Carbon Scenario, IPL Projected CO2 Emissions, Excluding Market Economy Energy Purchases

Year	2005 CO2 Emissions, Tons	IRP Projected CO_2 Emissions, Tons	Reduction from 2005
2014		10,418,142	-23%
2015		9,769,259	-28%
2016		9,928,315	-27%
2017		10,675,605	-21%
2018		10,971,114	-19%
2019		10,070,398	-26%
2020		9,970,245	-26%
2021	13,543,723	9,147,369	-32%
2022		9,055,221	-33%
2023		8,957,247	-34%
2024		8,897,004	-34%
2025		8,743,688	-35%
2026		8,615,522	-36%
2027		8,518,430	-37%
2028		8,445,628	-38%
2029		8,485,418	-37%

The No Carbon Scenario values are shown to represent a conservative approach. Reductions in CO_2 emissions under the Minnesota Midpoint 2017 Carbon Scenario would look slightly better.

IPL has already retired or fuel switched several coal-fired units (for example: Sixth Street, Dubuque and Sutherland). The 2014 Resource Plan includes significant wind additions and also includes several potential [TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

8.4 Rate Impact of Minnesota Renewable Requirements

Appendix 8A provides a report on the rate impact of Minnesota's RES and SES. In short:

- IPL's recent renewable additions have had some rate impact relative to MISO Load Zone LMPs. The largest impact being $1.75/MWH or 2 percent additional revenue requirements for 2012, without considerations for externalities.
- Recent renewable additions are appropriate when looking to the future with EGEAS PVRR savings of -0.54 percent. Annual impacts

are in the range of -\$0.58/MWH to +\$0.94/MWH, or -0.8 percent to +2.8 percent.

- IPL's 2014 IRP economically selects significant wind additions regardless of RES requirements. These additions are effectively adequate to meet long term RES requirements. Additional REC purchases will be needed in the meantime. IPL's surplus of Iowa allocated of RECs may be able available for as a supply source.
- The impact for the Minnesota Solar Energy Standard is an increase of approximately 0.1% in annual costs, or \$0.11/MWH assuming a forced addition in 2020. However, if incremental system costs with the solar installation are spread over just Minnesota retail load, the impact is roughly \$2.40/MWH.

RENEWABLE STANDARDS RATE IMPACTS

The following is an estimate of the Minnesota Renewable Energy Standard (RES) and Solar Energy Standard (SES) on IPL's Minnesota rates. This analysis uses estimates and projections, and as such should not be construed as final conclusions regarding potential rate impacts on IPL's customers.

I. Historical Impact of 2007-2013 RES Facility Additions

To provide the estimated historical impact of the RES facility additions on rates, IPL compared MISO's Day-Ahead LMPs to acquired renewable costs for the years 2007 through 2013. This comparison provides a cost delta between the acquired renewables and potential replacement LMPs.

There have been three significant renewable additions since the RES was implemented in 2007:

- The Hardin Hilltop Windfarm PPA with a commercial operation date of May 2007;
- The IPL-owned WWE with a commercial operation date of December 2009; and
- The Junction Hilltop PPA with a commercial operation date of March 2012.

The $/MWH impact and annual revenue percentage impact is shown in Table 1 below, with negative values indicating that the renewable investments were less costly than LMPs.

Table 1 – Historical RES Impact

Year	RES Impact $/MWH	RES Annual Revenue Impact %
2007	$(0.01)	-0.01%
2008	$(0.02)	-0.03%
2009	$0.07	0.09%
2010	$0.93	1.02%
2011	$1.64	1.89%
2012	$1.75	1.94%
2013	$1.67	1.85%

The acquired renewables were slightly lower than LMPs in 2007 and 2008 and slightly higher for 2009 through 2013. Driving results for 2009 through 2013 were the change to the economy and lower natural gas prices which resulted in drastically lower LMPs as shown in Table 8 below.

Table 2 – Average Day-Ahead LMPs

Year	Off Peak LMP $/MWH	On Peak LMP $/MWH
2007	$32.65	$63.83
2008	$31.62	$63.88
2009	$17.59	$33.04
2010	$22.38	$39.66
2011	$19.79	$35.55
2012	$18.87	$33.71
2013	$23.66	$39.62

In comparison:

- The PPA price for Hardin Hilltop is **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]**
- The PPA price for Junction Hilltop is **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]**

For this analysis IPL assumed a historical fixed price for WWE of $56.40/MWH.

It is important to recognize the renewable portfolio additions are made to meet long term needs and cost projections, so a short term backward looking analysis does not paint the full picture.

II. Future Impact of 2007-2013 RES Facility Additions

To provide the estimated impact of 2007-2013 RES facility additions on future rates, IPL used models from its 2014 IRP. The Minnesota Midpoint 2017 Carbon scenario includes the recent RES additions of Hardin Hilltop, Junction Hilltop and WWE, while case c032 (No Recent RES Additions) does not. The EGEAS model considers costs over the time period of 2014 to 2029 with an additional 35 year extension period to capture end effects.

The EGEAS analysis indicates lower PVRR due to the recent RES additions. The delta is $96 million on a $17.6 billion plan, or 0.5%. With the recent RES additions in the model, the EGEAS annual revenue requirements are slightly higher for 2014-2017 and the same or slightly lower for 2018-2029 and assumedly into the extension period. The deltas are shown in the figures below.

Figure 1 – 2007-2013 RES Additions Impact on Future Rates, % of Annual Revenue Requirements

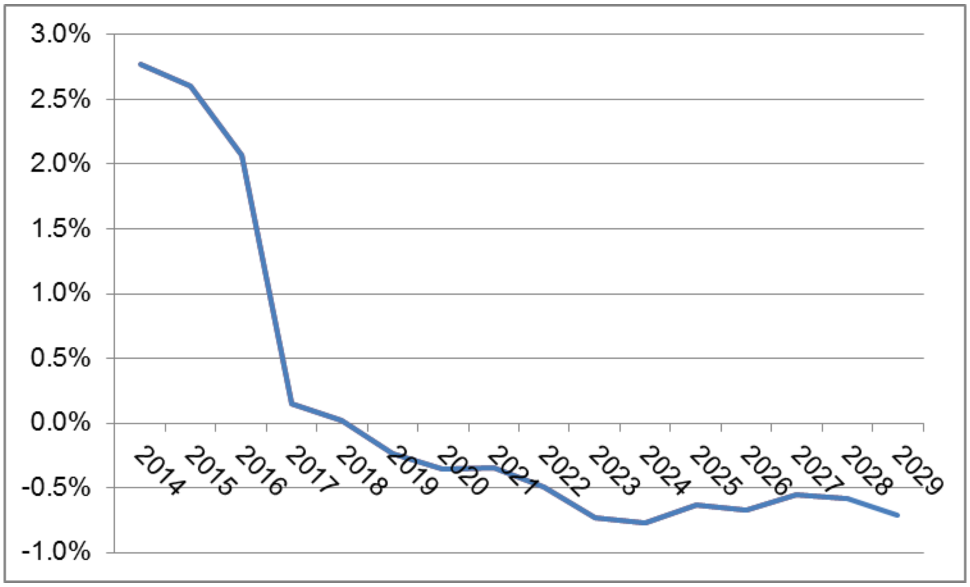
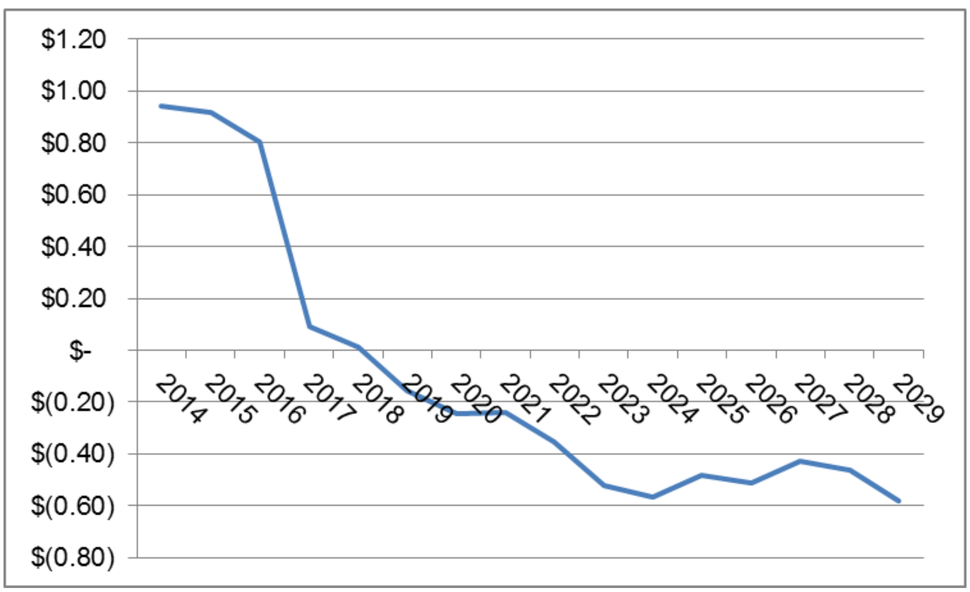


Figure 2 – 2007-2013 RES Additions Impact on Future Rates, $/MWH



III. Future Impact of RES Compliance through Resource Additions

IPL's 2014 IRP Reference economically selects the addition of 1,100 MW of wind by 2029 in both the No Carbon Scenario and the Minnesota Midpoint 2017 Carbon Scenario. With this addition, new and existing wind resources would account for approximately 25 percent of the energy portfolio by 2029. Since these additions are selected economically, and not forced into the modeling for the RES, further additions solely for the RES do not appear necessary. IPL will need to reassess this situation in future resource plans.

IV. Historical Impact of RES Compliance through REC Purchases

IPL allocates Renewable Energy Credits (RECs) between its Iowa and Minnesota jurisdictions. The Minnesota jurisdiction has higher renewable percentage requirements than Iowa, but is roughly 5.5 percent of the IPL system. Iowa renewable requirements are much lower than Minnesota, which creates a surplus of Iowa allocated RECs. The Iowa surplus is well above projected Minnesota shortfalls.

In 2012, IPL transferred 24,000 RECs between two Midwest Renewable Energy Tracking System (M-RETS) subaccounts; The 24,000 RECs originated from a subaccount held for Iowa allocated RECs and were transferred to a subaccount held for Minnesota allocated RECs. IPL plans to reallocate these REC purchases to Minnesota customers as a REC purchase and recover these costs through the Renewable Energy Rider. Under four-year shelf-life eligibility these 2010 vintage RECs can be used through the 2014 compliance year. The purchase price was **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]**, for a total of **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]**. With Minnesota annual collections in the tens of millions, this REC purchase has a negligible impact to rates.

V. Future Impact of RES Compliance through REC Purchases

IPL's 2014 IRP Reference Case economically selects 1,100 MW of new wind resources in the 2018-2029 timeframe, regardless of the RES. This results in existing and new wind resources contributing 25 percent of the energy portfolio by 2029. Assuming IPL acts to construct/acquire these wind resources, IPL's Minnesota customers would essentially meet the 25 percent by 2025 renewable portfolio standard in the long term. However, before 2027, there would be some Minnesota REC shortages that would require allocation/purchase of RECs. Assuming current market value for RECs of $1.25, this impact is shown in the table below.

As mentioned previously, IPL expects a continued surplus of Iowa allocated RECs. As such, these Iowa allocated surplus RECs could be used as a supply to close the remaining gap on Minnesota RES requirements as new wind additions are added to the portfolio.

Table 3 – Projected Minnesota REC Shortfall[1] After Resource Additions, and REC Purchase Impact

Year	REC Shortfall	REC Purchase, k$	Minnesota Retail MWH	REC Purchase $/MWH Impact
2014	(7,024)	$8.8	843,247	$0.01
2015	(23,004)	$28.8	841,904	$0.03
2016	(65,560)	$81.9	841,126	$0.10
2017	(66,488)	$83.1	839,968	$0.10
2018	(67,110)	$83.9	839,152	$0.10
2019	(50,855)	$63.6	845,987	$0.08
2020	(61,918)	$77.4	853,453	$0.09
2021	(45,358)	$56.7	860,983	$0.07
2022	(30,423)	$38.0	868,589	$0.04
2023	(13,747)	$17.2	876,275	$0.02
2024	0	$-	884,030	$0.00
2025	(29,038)	$36.3	891,854	$0.04
2026	(13,377)	$16.7	899,746	$0.02
2027	0	$-	907,708	$0.00

VI. Future Impact of SES Compliance through Resource Additions

Most EGEAS cases in IPL's 2014 IRP "force" into the expansion plan a minimum 10 MW solar addition by 2020. IPL enforced this minimum amount of solar to represent the impact of the Minnesota SES. The modeling may select additional solar if economic; however, such additional solar was not selected in any of the expansion plans.

Case c031 under the Minnesota Midpoint 2017 Carbon Scenario removes this minimum solar requirement to understand cost impacts. Removing the solar requirement reduced the PVRR $17 million, and did not otherwise impact the expansion plan. Removing the solar requirement translates to annual EGEAS savings of 0.1 percent, or $0.11/MWH for 2020 based on spreading these costs over the entire IPL system. However, if the incremental system costs are spread over only Minnesota retail load, the impact is roughly $2.40/MWH.

VII. Discussion of Assumptions

Costs are generally expressed in nominal terms, except for EGEAS PVRR. EGEAS costs are generation oriented and do not include existing sunk or future transmission and distribution costs (outside of direct connection costs for new

[1] Assuming 1100 MW of wind added by 2029 as shown in IPL's 2014 IRP Reference cases.

resources). M-RETS participation costs and staff time as a result of increased renewables are not included. System transmission upgrade costs to support higher levels of wind are not included. EGEAS assumptions are noted in the 2014 IRP.

VIII. RES Rate Impact Summary

IPL shares the following insights:

- IPL's recent renewable additions have had some rate impact relative to load zone LMPs. The largest impact being $1.75/MWH or 2 percent additional revenue requirements for 2012, without considerations for externalities.
- Recent renewable additions are appropriate when looking to the future with EGEAS PVRR savings of -0.54 percent. Annual impacts are in the range of -$0.58/MWH to +$0.94/MWH, or -0.8 percent to +2.8 percent.
- IPL's 2014 IRP economically selects significant wind additions regardless of RES requirements. These additions are effectively adequate to meet long term RES requirements. Additional REC purchases will be needed in the meantime. IPL's surplus of Iowa allocated of RECs may be able available as a supply source.
- The impact for the Minnesota Solar Energy Standard is an increase of approximately 0.1% in annual costs, or $0.11/MWH assuming a forced addition in 2020. However, if incremental system costs with the solar installation are spread over just Minnesota retail load, the impact is roughly $2.40/MWH.

SUMMARY

This is a summary of IPL's 2014 Resource Plan.

9.0 The IPL System

IPL is a regulated utility company that provides electricity and natural gas to retail customers in two Midwestern states. Today, IPL serves more than 525,000 electric customers and more than 230,000 natural gas customers in over 100 counties in Iowa and Minnesota. IPL's electric customers are expected to have an internal peak demand of 3,121 MW in 2014, which is projected to grow 430 MW over the next 15 years. After reductions for demand response and coincident peak with MISO, IPL's 2014 resource adequacy obligations are 2,896 ZRCs, which is projected to grow by 399 ZRCs over the next 15 years assuming the base forecast.

IPL's service territory encompasses approximately 52,000 square miles, including over 22,000 miles of electric distribution line and over 5,000 miles of natural-gas transmission and distribution main. IPL currently owns generating facilities located in both Iowa and Minnesota. These owned units currently produce approximately 2,495 ZRCs towards MISO resource adequacy requirements.

IPL's portfolio includes base load plants, which operate year round and are fueled with coal. IPL's portfolio also includes intermediate or combined cycle units, such as the Emery Generating Station, which provide load following capability, and are primarily fueled with natural gas. Combustion turbines and diesel generators at various locations throughout IPL's system provide supplemental energy at points throughout the year when demand is highest. IPL also owns and operates a 200 MW wind farm, WWE, in Franklin County, Iowa, which it installed in 2009. Further, IPL is installing the approximate 650 MW Marshalltown Generation Station Combined Cycle facility with a planned spring 2017 in-service date. In addition to owned generation, IPL has purchased power contracts for approximately 250 MW from various wind resources as well as for approximately 400 MW from a nuclear plant, the DAEC. IPL delivers the energy and exceptional service that its customers and communities count on – safely, efficiently and responsibly.

9.1 Overview of Plan Development

The process used in developing this plan begins with the system load forecast. This forecast includes the needs of all IPL customers. The system load forecast at MISO coincident peak plus a reserve requirement is matched against existing capacity to determine IPL's preliminary resource needs. IPL's Load and Capability Table – Before Resource Additions is shown in Appendix 9A. By using the EGEAS computer model, all combinations of existing resources and modeled future resource alternatives are considered when determining the optimal expansion plan. Renewable alternatives, DSM programs and conventional supply-side units are all considered in the resource planning process. The objective within EGEAS is to minimize the cumulative present worth of revenue requirements for the 15-year planning period plus a 35-year extension period associated with meeting the energy needs of customers, while maintaining the MISO coincident peak planning reserve margin (PRM_{ucap}) of 7.3 percent in each year. However, system reliability and financial risks must also be considered. The ultimate goal is to minimize cost, maximize reliability and minimize risk under reasonable expectations of the future. Given reasonable assumptions and after careful consideration of costs, reliability and risks, a reference case is constructed.

Once a reference case is determined, IPL develops additional scenarios and sensitivities by changing various input assumptions (adjustments to load, supply side options and prices). Some of the scenarios and sensitivities are regulatory requirements, while IPL creates others by varying key input assumptions to provide supplemental insight.

9.2 Supply-side Resource Options

In arriving at the proposed Resource Plan, IPL considered many different types of resource options. On the supply-side, a broad range of technologies categorized as renewable, fossil fuel, purchased power and nuclear were reviewed.

9.2.1 Renewable

Renewable resources refer to resources that constantly renew themselves or that are regarded as practically inexhaustible. Renewable energy is applicable to IPL's utility system and, in addition, has positive environmental benefits. Eight renewable technologies discussed subsequently are wind, solar-photovoltaic, solar-thermal, biomass, geothermal, biogas-anaerobic digestion, biogas-landfill gas and hydro. Wind is the most prevalent renewable technology included in IPL's utility system resource mix. Renewable technologies, especially wind, are continuing to improve in efficiency and will be considered as resource options when applicable. IPL will continue to seek economically competitive renewable opportunities.

9.2.2 Fossil Fuel

Fossil fuel refers to any naturally occurring organic fuel such as petroleum, coal or natural gas. Most of the electrical energy generated by IPL's generating facilities is with fossil fuel. The electrical energy purchased utilizes a mix of technologies. However, a significant percentage of this purchased energy is produced from fossil fuel technologies. Fossil fuel technologies continue to be attractive resource options for IPL; however, IPL currently does not have any plans for new coal resources.

9.2.3 Purchased Power

IPL purchases electrical energy from the MISO, other utilities, independent developers and power marketers. The decisions regarding purchased power are primarily functions of need, availability and cost. IPL will continue to purchase power when it makes sense to do so.

9.2.4 Nuclear

Nuclear refers to a facility in which heat produced in a reactor by the fissioning of nuclear fuel is used to drive a steam generator. Typical nuclear units are rated at 600 MW or larger and have high capital requirements. Black & Veatch did provide cost and characteristic estimates for a new nuclear generating unit and nuclear was modeled as a resource alternative in the EGEAS analysis for this Resource Plan.

9.3 Demand-side Resource Options

DSM programs for this Resource Plan are categorized into two types of programs: conservation (non-dispatchable) and load management (dispatchable). IPL has achieved considerable demand and energy savings from DSM programs. DSM programs will continue to be a potential resource alternative provided DSM is economical.

9.4 Resource Plan

IPL examined many scenarios when developing this resource plan. The cost summaries of the scenario analyses are provided in Appendix 9B. The resulting expansion plans for the Reference Cases of the various Carbon scenarios from this analysis can be found in Appendix 9C.

9.5 Upcoming Resource Activities

The resources needed to meet IPL's system capacity and energy requirements come primarily from three types of resources; demand-side, supply-side and renewable resources. During the forthcoming years, IPL will:

- Continue to pursue DSM activities;
- Investigate and pursue renewable energy alternatives;
- Purchase capacity in the short term to satisfy MISO Resource Adequacy obligations;
- Complete construction of the approximate 650 MW combined cycle MGS;
- Pursue capacity and efficiency upgrades at Tier 1 coal-fired units;
- Pursue reasonable emission controls and/or natural gas conversions on its remaining Tier 2 coal-fired units;
- Retire older peaking units;
- Retire older intermediate steam units;
- Fuel switch the Sutherland CTs from oil to natural gas operations; and

- Consider all supply-side options and only commit to resources that are in IPL's and IPL's customers' best interest.

In addition, IPL is engaged in transmission and environmental related activities which are also discussed below. The analysis of all options is ongoing.

9.5.1 Upcoming DSM Activities

IPL's current DSM programs have been aggressively pursued and are continuing to save kilowatts and kilowatt-hours. DSM activity is reported annually in all regulatory jurisdictions in which IPL serves retail customers. These filings on DSM programs to various agencies are expected to continue. IPL will continue to analyze potential demand and energy savings from future DSM activities.

9.5.2 Upcoming Supply-Side Activities

IPL is committed to meeting the demands of its customers. In Section 5, the types of resources required to meet IPL's customer needs were identified. Without resource additions other than MGS, IPL projections show a short-term capacity shortfall in 2015 and 2016, and then no shortfall until 2023. IPL plans to meet its resource needs consistent with the regulations of the governing jurisdictions. The immediate incremental capacity and energy needs through 2019 will most likely be met with existing resources, MISO market energy, capacity purchases in 2015 and 2016 (as necessary), and the installation of MGS in 2017.

In this Resource Plan, IPL considered the ongoing viability of its older peaking and intermediate steam units. As discussed in Section 6, IPL plans to retire [TRADE SECRET DATA BEGINS [redacted] Retirements are subject to approval from the MISO through the Attachment Y process. TRADE SECRET DATA ENDS]

[TRADE SECRET DATA BEGINS At its [redacted] Tier 2 unit Kapp 2 will fuel switch from coal to natural gas operation in the spring of 2015. TRADE SECRET DATA ENDS] At its Tier 1 coal-fired units Neal 3 and 4, Louisa, Ottumwa, and Lansing 4, IPL will install emission controls for MATS compliance, and IPL will pursue capacity and efficiency upgrades.

IPL will switch fuel from oil to natural gas at the Sutherland CTs in 2017.

The Resource Plan includes the committed construction and installation of the approximate 650 MW MGS combined cycle facility in 2017.

IPL customers' demands will be met and customers' rates will be kept as low as reasonably possible. This action plan will continually be reviewed and revised, as new information with respect to IPL's resource needs becomes available. IPL's resource planning process is continuously iterative and Electric

Integrated Resource Plans are regularly filed in Minnesota and Iowa. In the interim, all resource options will continue to be considered and evaluated.

9.5.3 Upcoming Renewable Activities

IPL continues to consider renewable energy, especially wind energy, a viable option for future resource needs. Currently, IPL purchases capacity and energy from approximately 250 MW of wind turbines. Also, IPL's 200 MW nameplate WWE came online at the end of 2009. These existing resources are expected to allow IPL to obtain a renewable energy portfolio of over 8 percent of energy in the next five years. As shown in Appendix 9D, IPL is projecting a surplus of over 1,000,000 MWH per year relative to Iowa's current renewable energy requirements for the next 10 years. This surplus declines as renewable agreements expire (before resource additions), but is more than adequate to meet the combined requirements of Iowa and Minnesota.

Also shown in Appendix 9D, IPL will eventually fall short of Minnesota's renewable requirements which increase to 25% by 2025. IPL has a current "bank" of approximately 37,700 renewable energy credits ("REC" / "RECs"). Even with this REC bank, without further action IPL will fall short of Minnesota's renewable requirements in 2014. The Minnesota shortfall is roughly:

- 23,000 RECs per year in 2013 to 2015 for the 12% requirement;
- 67,000 RECs per year in 2016 to 2019 for the 17% requirement;
- 103,000 RECs per year in 2020 to 2024 for the 20% requirement; and
- Over 150,000 RECs per year in 2025 to 2029 for the 25% requirement.

Note that these values are before consideration of the future resource additions identified in this Resource Plan.

When considering IPL collectively, IPL's surplus in Iowa could be used to meet a deficit in Minnesota and then all renewable energy requirements would be met system-wide for IPL. Further, expansion plans for the 2014 IRP include significant wind additions, such that new and existing wind constitutes approximately 25% of the energy portfolio. Therefore, IPL in total is well positioned to meet both its Iowa and Minnesota renewable energy requirements absent any purchases of M-RETS Certificates. IPL's Renewable Energy Production is shown in Appendix 9F.

The recently passed Minnesota SES requires IPL to generate or procure sufficient solar energy to serve 1.5 percent of its Minnesota retail load, with at least 10 percent of the 1.5 percent to be served from PV with a nameplate of 20 kilowatts or less. This requirement is separate from the Minnesota 25 percent renewable standard previously discussed.

IPL estimates solar installations Company-wide of roughly 8 MW to meet compliance. To capture the impact of the SES on the expansion plan in the 2014 IRP, IPL set EGEAS modeling constraints such that a minimum of 10 MW of solar was selected by 2020. The optimization modeling could select more, if economic. The EGEAS output results did not select any more than the minimum amount required.

9.6 Effect on Electric Rates

IPL develops resource plans based on the lowest cumulative present worth of revenue requirements, given regulatory and other constraints. All reasonable resource alternatives (demand-side and supply-side) are modeled, evaluated and optimized using EGEAS. This ensures an optimum plan and, as a result, customers' rates will be as low as practicable.

The EGEAS results indicate that IPL's total generation supply costs (fuel, operations & maintenance, and new capital fixed charges) per kWh will increase nominally over the study period at an average rate of about:

- 4.5 percent per year for the No Carbon scenario; and
- 5.8 percent per year for the Minnesota Midpoint 2017 Carbon scenario.

Assuming an inflation rate of approximately 2 percent per year over that same time period, the change in real terms is approximately:

- 2.4 percent per year for the No Carbon scenario; and
- 3.7 percent per year for the Minnesota Midpoint 2017 Carbon scenario.

As a reasonable cost electricity manufacturer, IPL will continue to provide reliable, responsible and affordable electric energy to its customers.

As IPL has done in the past, IPL will continue to evaluate the service needs of its customers, the costs of various resources, the applicability of new technologies, and other factors related to resource planning. IPL is committed to meeting the demands of its customers with economic, reliable, environmentally sound and safe energy.

IPL Projected Load and Generating Capability Data
Reference Case - Before Resource Additions (other than MGS)

IPL		2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030
Non-Coincident Peak		3121.3	3151.7	3179.1	3205.7	3232.8	3257.6	3284.6	3311.8	3339.3	3368.8	3398.5	3428.4	3458.6	3489.1	3519.9	3550.9
Coincident Peak	96.44%	3010.2	3039.5	3065.9	3091.5	3117.7	3141.6	3167.6	3193.9	3220.4	3248.8	3277.5	3306.3	3335.5	3364.9	3394.6	3424.5
Less Trans Loss Factor	2.49%	2935.2	2963.8	2989.5	3014.6	3040.0	3063.4	3088.8	3114.4	3140.2	3167.9	3195.8	3224.0	3252.4	3281.1	3310.0	3339.2
Demand Resources, Interruptible		263.3	265.4	267.5	269.6	271.8	274.0	276.2	278.4	280.6	282.8	285.1	287.4	289.7	292.0	294.3	296.7
Demand Resources, Direct Load Control		38.5	39.0	39.5	40.0	40.5	41.0	41.5	42.0	42.5	43.0	43.5	44.0	44.5	45.0	45.5	46.0
Interrupt and DLC less tran loss		301.8	304.4	307.0	309.6	312.3	315.0	317.7	320.4	323.1	325.8	328.6	331.4	334.2	337.0	339.8	342.7
Full Responsibility Sales																	
Full Responsibility Purchases																	
Adjusted Net Demand		2633.4	2659.4	2682.5	2705.0	2727.7	2748.4	2771.1	2794.0	2817.1	2842.1	2867.2	2892.6	2918.2	2944.1	2970.2	2996.5
Weighted LBA TM losses	2.50%	65.8	66.4	67.0	67.5	68.1	68.6	69.2	69.8	70.3	71.0	71.6	72.2	72.9	73.5	74.2	74.8
Planning Reserve Margin	7.30%	197.0	199.0	200.7	202.4	204.1	205.6	207.3	209.1	210.8	212.7	214.5	216.4	218.4	220.3	222.2	224.2
IPL Obligation		2896.2	2924.8	2950.2	2974.9	2999.9	3022.6	3047.6	3072.8	3098.3	3125.7	3153.4	3181.3	3209.5	3237.9	3266.6	3295.5
IPL Resources		2929.9	2829.2	2770.6	3066.1	3068.0	3080.2	3080.2	3073.1	3073.1	3073.1	3069.0	2790.1	2790.1	2783.1	2636.7	2636.7
IPL Position (Long/short)		**33.7**	**(95.5)**	**(179.6)**	**91.2**	**68.1**	**57.5**	**32.6**	**0.4**	**(25.1)**	**(52.6)**	**(84.3)**	**(391.2)**	**(419.4)**	**(454.8)**	**(630.0)**	**(658.9)**

EGEAS Present Value Revenue Requirements ($M 2013$)

2014 IRP

		"a" series	"b" series	"c" series	delta vs case 001 "a" series	delta vs case 001 "b" series	delta vs case 001 "c" series
EGEAS Case #	Case Description	No Carbon	Wood Mackenzie 2023 Carbon	Minnesota Midpoint 2017 Carbon (and Midpoint Externalities)	No Carbon	Wood Mackenzie 2023 Carbon	Minnesota Midpoint 2017 Carbon (and Midpoint Externalities)
_001	Base Assumptions (Reference Case)	15,220.0	16,883.8	17,636.7	-	-	-
_002	High Load Forecast	16,193.5	18,009.6	18,764.8	973.5	1,125.8	1,128.1
_003	Low Load Forecast	14,274.1	15,797.5	16,532.7	(945.9)	(1,086.3)	(1,103.9)
_004	No Economy Energy	15,780.8	17,414.9	18,169.3	560.7	531.1	532.7
_005	Natural Gas Prices +10% (and On Peak Market Energy)	15,512.2	17,258.4	17,980.5	292.1	374.6	343.9
_006	Natural Gas Prices +20% (and On Peak Market Energy)	15,797.1	17,560.9	18,286.5	577.1	677.1	649.8
_007	Natural Gas Prices +30% (and On Peak Market Energy)	16,079.0	17,847.8	18,589.3	859.0	964.0	952.6
_008	Natural Gas Prices -10% (and On Peak Market Energy)	14,903.8	16,437.4	17,179.7	(316.2)	(446.4)	(457.0)
_009	Natural Gas Prices -20% (and On Peak Market Energy)	14,490.7	15,934.9	16,613.2	(729.3)	(948.9)	(1,023.5)
_010	Natural Gas Prices -30% (and On Peak Market Energy)	13,944.4	15,372.4	15,977.1	(1,275.6)	(1,511.4)	(1,659.6)
_011	Coal Prices +10% (and Off Peak Market Energy)	15,558.1	17,111.3	17,863.3	338.1	227.5	226.7
_012	Coal Prices +20% (and Off Peak Market Energy)	15,846.9	17,308.1	18,035.6	626.9	424.3	399.0
_013	Coal Prices +30% (and Off Peak Market Energy)	16,083.9	17,480.9	18,174.4	863.8	597.1	537.8
_014	Coal Prices -10% (and Off Peak Market Energy)	14,860.4	16,616.0	17,345.3	(359.6)	(267.8)	(291.4)
_015	Coal Prices -20% (and Off Peak Market Energy)	14,497.8	16,306.0	17,016.8	(722.2)	(577.8)	(619.9)
_016	Coal Prices -30% (and Off Peak Market Energy)	14,135.2	15,968.5	16,684.4	(1,084.8)	(915.3)	(952.2)
_017	New Unit Capital Costs +10%	15,572.4	17,250.5	18,002.9	352.4	366.7	366.2
_018	New Unit Capital Costs -10%	14,852.3	16,504.9	17,257.8	(367.7)	(378.9)	(378.9)
_019	Higher Wind Prices, +$20/MWH	15,595.5	17,569.6	18,346.6	375.5	685.8	710.0
_020	Higher Wind Prices, +$10/MWH	15,519.8	17,282.9	18,051.9	299.8	399.1	415.3
_021	Lower Wind Prices, -$10/MWH	14,806.9	16,461.2	17,214.1	(413.1)	(422.6)	(422.6)
_022	Lower Wind Prices, -$20/MWH	14,384.3	16,038.6	16,791.5	(835.7)	(845.2)	(845.2)
_023	CO2 Scenario - Minnesota High			18,726.8			1,090.2
_024	CO2 Scenario - Minnesota Low			16,174.5			(1,462.1)
_025	Externalities High			17,643.5			6.8
_026	Externalities Low			17,630.2			(6.5)
_027	50% DSM and Renewables			17,906.4			269.7
_028	75% DSM and Renewables			18,197.9			561.3
_029	SO2 allowance cost $1,000/ton			17,707.3			70.6
_030	SO2 allowance cost $2,000/ton			17,772.5			135.8
_031	No Forced Solar			17,619.6			(17.0)
_032	No Recent RES additions			17,732.7			96.0

MSN DSM Analysis (DSM costs added outside of EGEAS)

		"a" series	"b" series	"c" series	delta vs case c031 "a" series	delta vs case c031 "b" series	delta vs case c031 "c" series
EGEAS Case #	Case Description	No Carbon	Wood Mackenzie 2023 Carbon	Minnesota Midpoint 2017 Carbon (and Midpoint Externalities)	No Carbon	Wood Mackenzie 2023 Carbon	Minnesota Midpoint 2017 Carbon (and Midpoint Externalities)
_033	Base MN DSM	15,265.1		17,681.8	-		-
_034	High MN DSM	15,296.0		17,695.8	30.9		14.1
_035	Medium MN DSM	15,288.0		17,700.0	22.9		18.2
_036	Low MN DSM	15,284.9		17,710.4	19.8		28.6

Total Additions 2014-2029
"a" series, No Carbon

				c25	d25	e25	f25	g25	h25	i25	j25	k25	l25	m25
Case	Description	PVRR, $M	PVRR delta from _001	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
a001	Base Assumptions (Reference Case)	15,220.0	-	300	0	0	0	604.701	0	0	1100	10	0	647.599
a002	High Load Forecast	16,193.5	973.5	950	0	191.7	0	604.701	0	0	1100	10	0	647.599
a003	Low Load Forecast	14,274.1	(945.9)	950	0	191.7	0	0	0	0	1100	10	0	647.599
a004	No Economy Energy	15,780.8	560.7	300	0	0	0	604.701	0	0	1100	10	0	647.599
a005	Natural Gas Prices +10% (and On Peak Market Energy)	15,512.2	292.1	300	0	0	0	604.701	0	0	1100	10	0	647.599
a006	Natural Gas Prices +20% (and On Peak Market Energy)	15,797.1	577.1	300	0	0	0	604.701	0	0	1100	10	0	647.599
a007	Natural Gas Prices +30% (and On Peak Market Energy)	16,079.0	859.0	300	0	0	0	604.701	0	0	1100	10	0	647.599
a008	Natural Gas Prices -10% (and On Peak Market Energy)	14,903.8	(316.2)	300	0	0	0	604.701	0	0	1000	10	0	647.599
a009	Natural Gas Prices -20% (and On Peak Market Energy)	14,490.7	(729.3)	400	0	0	0	604.701	0	0	700	10	0	647.599
a010	Natural Gas Prices -30% (and On Peak Market Energy)	13,944.4	(1,275.6)	500	0	0	0	604.701	0	0	600	10	0	647.599
a011	Coal Prices +10% (and Off Peak Market Energy)	15,558.1	338.1	300	0	0	0	604.701	0	0	1100	10	0	647.599
a012	Coal Prices +20% (and Off Peak Market Energy)	15,846.9	626.9	300	0	0	0	604.701	0	0	1100	10	0	647.599
a013	Coal Prices +30% (and Off Peak Market Energy)	16,083.9	863.8	300	0	0	0	604.701	0	0	1100	10	0	647.599
a014	Coal Prices -10% (and Off Peak Market Energy)	14,860.4	(359.6)	300	0	0	0	604.701	0	0	1100	10	0	647.599
a015	Coal Prices -20% (and Off Peak Market Energy)	14,497.8	(722.2)	300	0	0	0	604.701	0	0	1100	10	0	647.599
a016	Coal Prices -30% (and Off Peak Market Energy)	14,135.2	(1,084.8)	300	0	0	0	604.701	0	0	1100	10	0	647.599
a017	New Unit Capital Costs +10%	15,572.4	352.4	850	0	191.7	299.8	0	0	0	1000	10	0	647.599
a018	New Unit Capital Costs -10%	14,852.3	(367.7)	300	0	0	0	604.701	0	0	1100	10	0	647.599
a019	Higher Wind Prices, +$20/MWH	15,595.5	375.5	650	0	0	0	604.701	0	0	0	10	0	647.599
a020	Higher Wind Prices, +$10/MWH	15,519.8	299.8	400	0	0	0	604.701	0	0	600	10	0	647.599
a021	Lower Wind Prices, -$10/MWH	14,806.9	(413.1)	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
a022	Lower Wind Prices, -$20/MWH	14,384.3	(835.7)	700	0	191.7	299.8	0	0	0	1100	10	0	647.599

MSN DSM Analysis (DSM costs added outside of EGEAS)
"a" series, No Carbon

				c25	d25	e25	f25	g25	h25	i25	j25	k25	l25	m25
Case	Description	PVRR, $M	PVRR delta from c033	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
a033	Base MN DSM	15,265.1	-	300	0	0	0	604.701	0	0	1100	10	0	647.599
a034	High MN DSM	15,296.0	30.9	650	0	191.7	299.8	0	0	0	1100	10	0	647.599
a035	Medium MN DSM	15,288.0	22.9	750	0	191.7	299.8	0	0	0	1100	10	0	647.599
a036	Low MN DSM	15,284.9	19.8	300	0	0	0	604.701	0	0	1100	10	0	647.599

Total Additions 2014-2029
"b" series, Wood Mackenzie 2023 Carbon

Case	Description	PVRR, $M	PVRR delta from _001	c25 1 yr pk pwr purch	d25 CT-88	e25 CT-192	f25 cc-300	g25 cc-605	h25 PC w/CC	i25 PC	j25 wind	k25 solar	l25 nuclear	m25 MGS
b001	Base Assumptions (Reference Case)	16,883.8	-	300	0	0	0	604.701	0	0	1100	10	0	647.599
b002	High Load Forecast	18,009.6	1,125.8	950	0	191.7	0	604.701	0	0	1100	10	0	647.599
b003	Low Load Forecast	15,797.5	(1,086.3)	800	0	191.7	0	0	0	0	1100	10	0	647.599
b004	No Economy Energy	17,414.9	531.1	300	0	0	0	604.701	0	0	1100	10	0	647.599
b005	Natural Gas Prices +10% (and On Peak Market Energy)	17,258.4	374.6	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
b006	Natural Gas Prices +20% (and On Peak Market Energy)	17,560.9	677.1	300	0	0	0	604.701	0	0	1100	10	0	647.599
b007	Natural Gas Prices +30% (and On Peak Market Energy)	17,847.8	964.0	300	0	0	0	604.701	0	0	1100	10	0	647.599
b008	Natural Gas Prices -10% (and On Peak Market Energy)	16,437.4	(446.4)	300	0	0	0	604.701	0	0	1100	10	0	647.599
b009	Natural Gas Prices -20% (and On Peak Market Energy)	15,934.9	(948.9)	300	0	0	0	604.701	0	0	1100	10	0	647.599
b010	Natural Gas Prices -30% (and On Peak Market Energy)	15,372.4	(1,511.4)	300	0	0	0	604.701	0	0	1100	10	0	647.599
b011	Coal Prices +10% (and Off Peak Market Energy)	17,111.3	227.5	300	0	0	0	604.701	0	0	1100	10	0	647.599
b012	Coal Prices +20% (and Off Peak Market Energy)	17,308.1	424.3	300	0	0	0	604.701	0	0	1100	10	0	647.599
b013	Coal Prices +30% (and Off Peak Market Energy)	17,480.9	597.1	300	0	0	0	604.701	0	0	1100	10	0	647.599
b014	Coal Prices -10% (and Off Peak Market Energy)	16,616.0	(267.8)	300	0	0	0	604.701	0	0	1100	10	0	647.599
b015	Coal Prices -20% (and Off Peak Market Energy)	16,306.0	(577.8)	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
b016	Coal Prices -30% (and Off Peak Market Energy)	15,968.5	(915.3)	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
b017	New Unit Capital Costs +10%	17,250.5	366.7	300	0	0	0	604.701	0	0	1100	10	0	647.599
b018	New Unit Capital Costs -10%	16,504.9	(378.9)	300	0	0	0	604.701	0	0	1100	10	0	647.599
b019	Higher Wind Prices, +$20/MWH	17,569.6	685.8	500	0	0	0	604.701	0	0	600	10	0	647.599
b020	Higher Wind Prices, +$10/MWH	17,282.9	399.1	300	0	0	0	604.701	0	0	1100	10	0	647.599
b021	Lower Wind Prices, -$10/MWH	16,461.2	(422.6)	300	0	0	0	604.701	0	0	1100	10	0	647.599
b022	Lower Wind Prices, -$20/MWH	16,038.6	(845.2)	300	0	0	0	604.701	0	0	1100	10	0	647.599

Total Additions 2014-2029
"c" series, Minnesota Midpoint 2017 Carbon

				c25	d25	e25	f25	g25	h25	i25	j25	k25	l25	m25
Case	Description	PVRR, $M	PVRR delta from _001	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
c001	Base Assumptions (Reference Case)	17,636.7	-	300	0	0	0	604.701	0	0	1100	10	0	647.599
c002	High Load Forecast	18,764.8	1,128.1	950	0	191.7	0	604.701	0	0	1100	10	0	647.599
c003	Low Load Forecast	16,532.7	(1,103.9)	800	0	191.7	0	0	0	0	1100	10	0	647.599
c004	No Economy Energy	18,169.3	532.7	300	0	0	0	604.701	0	0	1100	10	0	647.599
c005	Natural Gas Prices +10% (and On Peak Market Energy)	17,980.5	343.9	300	0	0	0	604.701	0	0	1100	10	0	647.599
c006	Natural Gas Prices +20% (and On Peak Market Energy)	18,286.5	649.8	300	0	0	0	604.701	0	0	1100	10	0	647.599
c007	Natural Gas Prices +30% (and On Peak Market Energy)	18,589.3	952.6	300	0	0	0	604.701	0	0	1100	10	0	647.599
c008	Natural Gas Prices -10% (and On Peak Market Energy)	17,179.7	(457.0)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c009	Natural Gas Prices -20% (and On Peak Market Energy)	16,613.2	(1,023.5)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c010	Natural Gas Prices -30% (and On Peak Market Energy)	15,977.1	(1,659.6)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c011	Coal Prices +10% (and Off Peak Market Energy)	17,863.3	226.7	300	0	0	0	604.701	0	0	1100	10	0	647.599
c012	Coal Prices +20% (and Off Peak Market Energy)	18,035.6	399.0	300	0	0	0	604.701	0	0	1100	10	0	647.599
c013	Coal Prices +30% (and Off Peak Market Energy)	18,174.4	537.8	300	0	0	0	604.701	0	0	1100	10	0	647.599
c014	Coal Prices -10% (and Off Peak Market Energy)	17,345.3	(291.4)	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
c015	Coal Prices -20% (and Off Peak Market Energy)	17,016.8	(619.9)	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
c016	Coal Prices -30% (and Off Peak Market Energy)	16,684.4	(952.2)	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
c017	New Unit Capital Costs +10%	18,002.9	366.2	700	0	191.7	299.8	0	0	0	1100	10	0	647.599
c018	New Unit Capital Costs -10%	17,257.8	(378.9)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c019	Higher Wind Prices, +$20/MWH	18,346.6	710.0	400	0	0	0	604.701	0	0	600	10	0	647.599
c020	Higher Wind Prices, +$10/MWH	18,051.9	415.3	300	0	0	0	604.701	0	0	1100	10	0	647.599
c021	Lower Wind Prices, -$10/MWH	17,214.1	(422.6)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c022	Lower Wind Prices, -$20/MWH	16,791.5	(845.2)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c023	CO2 Scenario - Minnesota High	18,726.8	1,090.2	300	0	0	0	604.701	0	0	1100	10	0	647.599
c024	CO2 Scenario - Minnesota Low	16,174.5	(1,462.1)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c025	Externalities High	17,643.5	6.8	300	0	0	0	604.701	0	0	1100	10	0	647.599
c026	Externalities Low	17,630.2	(6.5)	300	0	0	0	604.701	0	0	1100	10	0	647.599
c027	50% DSM and Renewables													
c028	75% DSM and Renewables													
c029	SO2 allowance cost $1,000/ton	17,707.3	70.6	300	0	0	0	604.701	0	0	1100	10	0	647.599
c030	SO2 allowance cost $2,000/ton	17,772.5	135.8	300	0	0	0	604.701	0	0	1100	10	0	647.599
c031	No Forced Solar	17,619.6	(17.0)	300	0	0	0	604.701	0	0	1100	0	0	647.599
c032	No Recent RES additions	17,732.7	96.0	300	0	0	0	604.701	0	0	1100	10	0	647.599

MSN DSM Analysis (DSM costs added outside of EGEAS)
"c" series, Minnesota Midpoint 2017 Carbon

				c25	d25	e25	f25	g25	h25	i25	j25	k25	l25	m25
Case	Description	PVRR, $M	PVRR delta from c033	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
c033	Base MN DSM	17,681.8	-	300	0	0	0	604.701	0	0	1100	10	0	647.599
c034	High MN DSM	17,695.8	14.1	600	0	191.7	299.8	0	0	0	1100	10	0	647.599
c035	Medium MN DSM	17,700.0	18.2	300	0	0	0	604.701	0	0	1100	10	0	647.599
c036	Low MN DSM	17,710.4	28.6	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: No Carbon
Case: a001 Base Assumptions (Reference Case)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	100	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Wood Mackenzie 2023 Carbon
Case: b001 Base Assumptions (Reference Case)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL 2014 IRP

Scenario: Minnesota Midpoint 2017 Carbon
Case: c001 Base Assumptions (Reference Case)

	1 yr pk pwr purch	CT-88	CT-192	cc-300	cc-605	PC w/CC	PC	wind	solar	nuclear	MGS
YEAR	1	2	3	4	5	6	7	8	9	10	11
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
2014	0	0	0	0	0	0	0	0	0	0	0
2015	100	0	0	0	0	0	0	0	0	0	0
2016	200	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	647.599
2018	0	0	0	0	0	0	0	100	0	0	0
2019	0	0	0	0	0	0	0	100	0	0	0
2020	0	0	0	0	0	0	0	100	10	0	0
2021	0	0	0	0	0	0	0	100	0	0	0
2022	0	0	0	0	0	0	0	100	0	0	0
2023	0	0	0	0	0	0	0	100	0	0	0
2024	0	0	0	0	0	0	0	100	0	0	0
2025	0	0	0	0	604.701	0	0	100	0	0	0
2026	0	0	0	0	0	0	0	100	0	0	0
2027	0	0	0	0	0	0	0	100	0	0	0
2028	0	0	0	0	0	0	0	100	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0
----	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------	--------
TOTAL	300	0	0	0	604.701	0	0	1100	10	0	647.599

IPL Renewable Status

Year	Retail and Wholesale Energy by State (Note 1)				Retail and Wholesale Demand by State (Note 1)			
	MN MWH Retail Sales	IA MWH Retail Sales	MN MWH Wholesale Sales	IA/IL MWH Wholesale Sales	MN MW Retail Demand	IA MW Retail Demand	MN MW Wholesale Demand	IA/IL MW Wholesale Demand
2012								
2013	(final numbers for 2013 not in yet)				(final numbers for 2013 not in yet)			
2014	843,247	14,586,528	843	489,462	175.7	2,562.8	0.1	80.8
2015	841,904	14,774,484	842	492,888	177.4	2,588.1	0.2	81.6
2016	841,126	14,921,185	843	496,338	179.0	2,610.6	0.2	82.4
2017	839,968	15,063,747	842	499,812	180.5	2,632.4	0.2	83.0
2018	839,152	15,208,606	843	503,311	182.0	2,654.6	0.2	83.7
2019	845,987	15,332,504	850	507,411	183.4	2,674.7	0.2	84.4
2020	853,453	15,467,692	851	511,885	184.9	2,696.8	0.2	85.1
2021	860,983	15,604,025	851	516,397	186.4	2,719.1	0.2	85.8
2022	868,589	15,741,729	851	520,954	188.0	2,741.6	0.2	86.5
2023	876,275	15,880,904	851	525,560	189.6	2,765.9	0.2	87.3
2024	884,030	16,021,309	851	530,207	191.3	2,790.4	0.2	88.0
2025	891,854	16,162,956	851	534,894	193.0	2,815.1	0.2	88.8
2026	899,746	16,305,855	851	539,623	194.7	2,840.0	0.2	89.6
2027	907,708	16,450,018	851	544,394	196.4	2,865.2	0.2	90.4
2028	915,741	16,595,455	851	549,207	198.2	2,890.6	0.2	91.2
2029	923,845	16,742,178	851	554,063	199.9	2,916.1	0.2	92.0

(Note 1) forecast as of October 2013

IPL Renewable Status

	REC Share Percentages For Sources Other Than Whispering Willow					
Year	MN MWH Retail Sales with 3.15% Distribution Energy Losses (Note 2)	IA/IL MWH Retail Sales with 3.15% Distribution Energy Losses (Note 2)	MWH Wholesale Sales	MN Retail REC Share Ratio (other than Whispering Willow)	IA Retail REC Share Ratio (other than Whispering Willow)	Wholesale REC Share Ratio (other than Whispering Willow)
2012				(assume 2013 ratios similar to 2014)		
2013	(final numbers for 2013 not in yet)			5.3%	91.7%	3.0%
2014	870,673	15,060,948	490,305	5.3%	91.7%	3.0%
2015	869,287	15,255,017	493,730	5.2%	91.8%	3.0%
2016	868,483	15,406,490	497,181	5.2%	91.9%	3.0%
2017	867,288	15,553,689	500,655	5.1%	91.9%	3.0%
2018	866,445	15,703,259	504,154	5.1%	92.0%	3.0%
2019	873,502	15,831,186	508,262	5.1%	92.0%	3.0%
2020	881,211	15,970,771	512,736	5.1%	92.0%	3.0%
2021	888,986	16,111,538	517,248	5.1%	92.0%	3.0%
2022	896,839	16,253,721	521,805	5.1%	92.0%	3.0%
2023	904,776	16,397,422	526,411	5.1%	92.0%	3.0%
2024	912,783	16,542,394	531,057	5.1%	92.0%	3.0%
2025	920,861	16,688,648	535,745	5.1%	92.0%	3.0%
2026	929,010	16,836,195	540,474	5.1%	92.0%	3.0%
2027	937,231	16,985,047	545,245	5.1%	92.0%	3.0%
2028	945,525	17,135,214	550,058	5.1%	92.0%	3.0%
2029	953,892	17,286,709	554,914	5.1%	92.0%	3.0%

(Note 2) REC Share Ratios adjust for 3.15% reasonable distribution energy losses to put Retail and Wholesale load at equivalent electric system level. Without adjustment, Retail Sales are generally at secondary and distribution level, Wholesale Sales generally at distribution and transmission level.

IPL Renewable Status

	REC Share Percentages For Whispering Willow (Note 3)					
Year	MN MW Retail Demand with 4.01% Distribution Demand Losses (Note 4)	IA MW Retail Demand with 4.01% Distribution Demand Losses (Note 4)	MW Wholesale Demand	MN Retail REC Share Ratio (Whispering Willow)	IA Retail REC Share Ratio (Whispering Willow)	Wholesale REC Share Ratio (Whispering Willow)
2012				(assume 2013 ratios similar to 2014)		
2013	(final numbers for 2013 not in yet)			6.2%	91.0%	2.8%
2014	183	2,670	81	6.2%	91.0%	2.8%
2015	185	2,696	82	6.2%	91.0%	2.8%
2016	186	2,720	83	6.2%	91.0%	2.8%
2017	188	2,742	83	6.2%	91.0%	2.8%
2018	190	2,765	84	6.2%	91.0%	2.8%
2019	191	2,786	85	6.2%	91.0%	2.8%
2020	193	2,809	85	6.2%	91.0%	2.8%
2021	194	2,833	86	6.2%	91.0%	2.8%
2022	196	2,856	87	6.2%	91.0%	2.8%
2023	198	2,881	87	6.2%	91.0%	2.8%
2024	199	2,907	88	6.2%	91.0%	2.8%
2025	201	2,933	89	6.2%	91.0%	2.8%
2026	203	2,959	90	6.2%	91.0%	2.8%
2027	205	2,985	91	6.2%	91.0%	2.8%
2028	206	3,011	91	6.2%	91.0%	2.8%
2029	208	3,038	92	6.2%	91.0%	2.8%

(Note 3) Whispering Willow costs, and RECs, are proposed to be allocated by coincident peak.

(Note 4) REC Share Ratios adjust for 4.01% reasonable distribution demand losses to put Retail and Wholesale load at equivalent electric system level. Without adjustment, Retail Sales are generally at secondary and distribution level, Wholesale Sales generally at distribution and transmission level.

IPL Renewable Status

	REC Shares Other than Whispering Willow				REC Shares for Whispering Willow				Total REC Shares			
Year	IPL Renewable MWH (RECs)	MN Retail REC Share	IA Retail REC Share	Wholesale REC Share	IPL Renewable MWH (RECs)	MN Retail REC Share	IA Retail REC Share	Wholesale REC Share	IPL Renewable MWH (RECs)	MN Retail REC Share	IA Retail REC Share	Wholesale REC Share
2012	(assume ratios similar to 2014)				(assume ratios similar to 2014)				(assume ratios similar to 2014)			
2013	740,106	39,240	678,769	22,097	639,069	39,868	581,558	17,643	1,379,175	79,108	1,260,327	39,740
2014	702,342	37,237	644,135	20,970	662,000	41,299	602,425	18,276	1,364,342	78,536	1,246,561	39,245
2015	702,073	36,725	644,489	20,859	662,000	41,299	602,425	18,276	1,364,073	78,024	1,246,914	39,135
2016	697,801	36,133	640,983	20,685	662,000	41,299	602,425	18,276	1,359,801	77,432	1,243,409	38,961
2017	683,027	35,007	627,811	20,208	662,000	41,299	602,425	18,276	1,345,027	76,306	1,230,236	38,484
2018	674,849	34,246	620,676	19,927	662,000	41,299	602,425	18,276	1,336,849	75,545	1,223,101	38,202
2019	658,919	33,438	606,025	19,456	662,000	41,299	602,425	18,276	1,320,919	74,737	1,208,450	37,732
2020	611,286	31,021	562,216	18,050	662,000	41,299	602,425	18,276	1,273,286	72,320	1,164,641	36,325
2021	608,101	30,860	559,285	17,955	662,000	41,299	602,425	18,276	1,270,101	72,159	1,161,711	36,231
2022	573,212	29,089	527,198	16,925	662,000	41,299	602,425	18,276	1,235,212	70,388	1,129,623	35,201
2023	572,921	29,075	526,929	16,916	662,000	41,299	602,425	18,276	1,234,921	70,374	1,129,355	35,192
2024	526,593	26,724	484,321	15,548	662,000	41,299	602,425	18,276	1,188,593	68,023	1,086,746	33,824
2025	481,929	24,458	443,242	14,229	662,000	41,299	602,425	18,276	1,143,929	65,756	1,045,667	32,505
2026	481,628	24,443	442,966	14,220	662,000	41,299	602,425	18,276	1,143,628	65,741	1,045,391	32,496
2027	453,325	23,006	416,935	13,384	662,000	41,299	602,425	18,276	1,115,325	64,305	1,019,360	31,660
2028	272,296	13,819	250,438	8,039	662,000	41,299	602,425	18,276	934,296	55,118	852,863	26,315
2029	(45,713)	(2,320)	(42,044)	(1,350)	662,000	41,299	602,425	18,276	616,287	38,979	560,382	16,926
	2013 supply estimated, final numbers not yet in. 2013 demand and energy values by state/customer class not yet in. Assume 2013 allocation rates similar to 2014.				2013 supply estimated, final numbers not yet in. 2013 demand and energy values by state/customer class not yet in. Assume 2013 allocation rates similar to 2014.				2013 supply estimated, final numbers not yet in. 2013 demand and energy values by state/customer class not yet in. Assume 2013 allocation rates similar to 2014.			

IPL Renewable Status

	Minnesota Status					Minnesota 4 Year Shelf Life Calculations			
Year	MN % Requirement of retail sales	MN REC Requirement for retail sales	MN Retail REC Share	MN RECs as % of Retail Sales	MN REC Status before 4 Year Shelf Life	4 Year Shelf Life REC balance BOY	4 Year Shelf Life REC balance EOY	REC req'ts unmet	4 Year Shelf Life REC's "Lost"
2012		(this represents 2012 banked RECs)			37,711	0	37,711	0	0
2013	12%	101,190	79,108	9.5%	(22,082)	37,711	15,629	0	0
2014	12%	101,190	78,536	9.3%	(22,653)	15,629	0	-7,024	0
2015	12%	101,029	78,024	9.3%	(23,004)	0	0	-23,004	0
2016	17%	142,991	77,432	9.2%	(65,560)	0	0	-65,560	0
2017	17%	142,795	76,306	9.1%	(66,488)	0	0	-66,488	0
2018	17%	142,656	75,545	9.0%	(67,110)	0	0	-67,110	0
2019	17%	143,818	74,737	8.8%	(69,081)	0	0	-69,081	0
2020	20%	170,691	72,320	8.5%	(98,371)	0	0	-98,371	0
2021	20%	172,197	72,159	8.4%	(100,038)	0	0	-100,038	0
2022	20%	173,718	70,388	8.1%	(103,329)	0	0	-103,329	0
2023	20%	175,255	70,374	8.0%	(104,881)	0	0	-104,881	0
2024	20%	176,806	68,023	7.7%	(108,783)	0	0	-108,783	0
2025	25%	222,963	65,756	7.4%	(157,207)	0	0	-157,207	0
2026	25%	224,937	65,741	7.3%	(159,195)	0	0	-159,195	0
2027	25%	226,927	64,305	7.1%	(162,622)	0	0	-162,622	0
2028	25%	228,935	55,118	6.0%	(173,817)	0	0	-173,817	0
2029	25%	230,961	38,979	4.2%	(191,982)	0	0	-191,982	0

2013 supply estimated, final numbers not yet in.
2013 demand and energy values by state/customer class not yet in.
Assume 2013 allocation rates similar to 2014.
Assume 2013 requirements similar to 2014. (Also similar to 2012)

IPL Renewable Status

	Iowa Status				
Year	IA % Requirement of retail sales (Note 5)	IA REC Requirement for retail sales	IA Retail REC Share	IA RECs as % of Retail Sales	IA REC Status before 4 Year Shelf Life
2012					
2013	0.8%	117,833	1,260,327	8.7%	1,142,494
2014	0.8%	117,833	1,246,561	8.5%	1,128,728
2015	0.8%	117,833	1,246,914	8.4%	1,129,081
2016	0.8%	117,833	1,243,409	8.3%	1,125,576
2017	0.8%	117,833	1,230,236	8.2%	1,112,403
2018	0.8%	117,833	1,223,101	8.0%	1,105,268
2019	0.8%	117,833	1,208,450	7.9%	1,090,617
2020	0.8%	117,833	1,164,641	7.5%	1,046,808
2021	0.8%	117,833	1,161,711	7.4%	1,043,878
2022	0.7%	117,833	1,129,623	7.2%	1,011,790
2023	0.7%	117,833	1,129,355	7.1%	1,011,522
2024	0.7%	117,833	1,086,746	6.8%	968,913
2025	0.7%	117,833	1,045,667	6.5%	927,834
2026	0.7%	117,833	1,045,391	6.4%	927,558
2027	0.7%	117,833	1,019,360	6.2%	901,527
2028	0.7%	117,833	852,863	5.1%	735,030
2029	0.7%	117,833	560,382	3.3%	442,549

(Note 5) IPL forecasted requirements based on 199 IAC 15.11(1) = 49.8 MW of capacity. IPL has identified this capacity as 65.1% of the 76.5 MW Buena Vista/Storm Lake Power Partners Wind Farm.

2013 supply estimated, final numbers not yet in.
2013 demand and energy values by state/customer class not yet in.
Assume 2013 allocation rates similar to 2014.

IPL Renewable Production in MWH/year

	Buena Vista Wind Farm [4]	Cerro Gordo Wind Farm [5]	Flying Cloud Wind Farm	Hancock Wind Farm	Hancock Second Nature Use	Hancock Sale to CIPCO	Neppel Wind Farm	Hardin Hilltop / Wind[2]	America's Hydro[8]	Sibley Hills
in M-RETS	Yes	Yes	Yes	Yes	-	-	Yes	Yes	No	No
state of location	IA	IA	IA	IA	IA	IA	IA	IA	IA	IA
nameplate MW	76.5	41.3	43.5	56.8	n/a	-2 (3.52%)	1.5	14.7	2.69	1.2
PPA vs owned	PPA	PPA	PPA	PPA	-	-	PPA	PPA	PPA	PPA
renewable type	wind	wind	wind	wind	wind	wind	wind	wind	hydro	wind
2013	194,040	89,818	143,173	146,252	-31,218	-5,148	4,802	49,183	8,000	1,954
2014	177,300	88,400	140,400	141,400	-35,350	-4,977	4,500	44,300	8,000	2,000
2015	177,300	88,400	140,400	141,400	-35,350	-4,977	4,500	44,300	8,000	2,000
2016	177,300	88,400	140,400	141,400	-35,350	-4,977	4,500	44,300	4,000	2,000
2017	177,300	88,400	140,400	141,400	-35,350	-4,977	4,500	44,300		2,000
2018	177,300	88,400	140,400	141,400	-35,350	-4,977	4,500	44,300		2,000
2019	177,300	88,400	140,400	141,400	-35,350	-4,977	2,250	44,300		2,000
2020	177,300	88,400	140,400	141,400	-35,350	-4,977		44,300		2,000
2021	177,300	88,400	140,400	141,400	-35,350	-4,977		44,300		2,000
2022	177,300	88,400	140,400	141,400	-35,350	-4,977		44,300		2,000
2023	177,300	88,400	140,400	141,400	-35,350	-4,977		44,300		2,000
2024	177,300	44,200	140,400	141,400	-35,350	-4,977		44,300		167
2025	177,300		140,400	141,400	-35,350	-4,977		44,300		
2026	177,300		140,400	141,400	-35,350	-4,977		44,300		
2027	177,300		140,400	141,400	-35,350	-4,977		44,300		
2028	177,300		140,400		-35,350					
2029					-35,350					

Notes:
1) Not yet built
2) Hardin Hilltop/Wind collection of CyHawk, Greene, Hardin, Poverty Ridge, Sutton, Wind Family, and Zontos
3) Allendorf (Sibley) aka NAE Allendorf LLC aka Navitas Energy Inc
4) Buena Vista aka Storm Lake Power Partners
5) Cerro Gordo aka Hawkeye Power Partners
6) Adams Wind Farm collection of G McNeilus, NcNeilus Windfarm LLC, and GARMAR Wind
7) Windom Wind Farm aka Bingham
8) America's Hydro collection of Maquoketa, Anamosa, and Iowa Falls Hydro

IPL Renewable Production in MWH/year

	Whispering Willow Wind Farm	Minn Wind I (Beaver Creek)	Minn Wind II (Beaver Creek)	Sieve Wind Farm	Ag Land Energy 1 and 3	Ag Land Energy 2	Ag Land Energy 5 & 6	Junction Hilltop Wind	Kirkwood Commnty College Wind Turbine	Arnold Wind	Wilmont Hills
in M-RETS	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
state of location	IA	MN	MN	MN	IA	IA	IA	IA	IA	MN	MN
nameplate MW	200	3.8		1	3.2	1.6	3.2	8	2.5	1.65	1.5
PPA vs owned	owned	PPA	PPA	PPA	PPA	PPA	PPA	PPA	PPA	PPA	PPA
renewable type	wind	wind	wind	wind	wind	wind	wind	wind	wind	wind	wind
2013	639,069	4,897	4,897	2,842	12,311	5,787	11,775	30,505	5,001	6,114	4,196
2014	662,000	5,100	4,900	2,900	11,200	5,600	11,200	28,000	6,600	5,800	5,500
2015	662,000	5,100	4,900	2,900	11,200	5,600	11,200	28,000	6,600	5,800	5,500
2016	662,000	5,100	4,900	2,900	11,200	5,600	11,200	28,000	6,600	5,800	5,500
2017	662,000	2,550	2,450	2,900	11,200	5,600	11,200	28,000	6,600	5,800	
2018	662,000				11,200	5,600	11,200	28,000	6,600	5,800	
2019	662,000				11,200	5,600	11,200	28,000	6,600	5,800	
2020	662,000				11,200	5,600	11,200	28,000	6,600	2,900	
2021	662,000				11,200	5,600	11,200	28,000	6,600		
2022	662,000							28,000			
2023	662,000							28,000			
2024	662,000							28,000			
2025	662,000							28,000			
2026	662,000							28,000			
2027	662,000										
2028	662,000										
2029	662,000										

Notes:

1) Not yet built
2) Hardin Hilltop/Wind collection of CyHawk, Greene, Hardin, Poverty Ridge, Sutton, Wind Family, and Zontos
3) Allendorf (Sibley) aka NAE Allendorf LLC aka Navitas Energy Inc
4) Buena Vista aka Storm Lake Power Partners
5) Cerro Gordo aka Hawkeye Power Partners
6) Adams Wind Farm collection of G McNeilus, NcNeilus Windfarm LLC, and GARMAR Wind
7) Windom Wind Farm aka Bingham
8) America's Hydro collection of Maquoketa, Anamosa, and Iowa Falls Hydro

IPL Renewable Production in MWH/year

	Wilmont Hills Second Nature Use	Adams Wind Farm[6]	Windom Wind Farm[7]	Additional Second Nature Use	Total MWH Other than Whispering Willow	Whispering Willow MWH	Total MWH With Whispering Willow
in M-RETS	-	Yes	Yes				
state of location	MN	MN	MN				
nameplate MW	n/a	6	15				
PPA vs owned	-	PPA	PPA	PPA			
renewable type	wind	wind	wind				
2013	-4,196	12,485	42,901	-264	740,106	639,069	1,379,175
2014	-5,500	13,400	42,200	-530	702,342	662,000	1,364,342
2015	-5,500	13,400	42,200	-800	702,073	662,000	1,364,073
2016	-5,500	13,400	42,200	-1,071	697,801	662,000	1,359,801
2017	-5,500	13,400	42,200	-1,346	683,027	662,000	1,345,027
2018	-5,500	13,400	42,200	-1,623	674,849	662,000	1,336,849
2019	-5,500		42,200	-1,903	658,919	662,000	1,320,919
2020	-5,500			-2,186	611,286	662,000	1,273,286
2021	-5,500			-2,472	608,101	662,000	1,270,101
2022	-5,500			-2,761	573,212	662,000	1,235,212
2023	-5,500			-3,052	572,921	662,000	1,234,921
2024	-5,500			-3,347	526,593	662,000	1,188,593
2025	-5,500			-3,644	481,929	662,000	1,143,929
2026	-5,500			-3,944	481,628	662,000	1,143,628
2027	-5,500			-4,248	453,325	662,000	1,115,325
2028	-5,500			-4,554	272,296	662,000	934,296
2029	-5,500			-4,863	-45,713	662,000	616,287

Notes:
1) Not yet built
2) Hardin Hilltop/Wind collection of CyHawk, Greene, Hardin, Poverty Ridge, Sutton, Wind Family, and Zontos
3) Allendorf (Sibley) aka NAE Allendorf LLC aka Navitas Energy Inc
4) Buena Vista aka Storm Lake Power Partners
5) Cerro Gordo aka Hawkeye Power Partners
6) Adams Wind Farm collection of G McNeilus, NcNeilus Windfarm LLC, and GARMAR Wind
7) Windom Wind Farm aka Bingham
8) America's Hydro collection of Maquoketa, Anamosa, and Iowa Falls Hydro

LOAD & CAPABILITY DATA

10.0 Load & Capability Table

The resulting load and generating capability table after resource additions for IPL can be found in Appendix 10A. In all years, 2014-2029, the reserve margin is at or above the required MISO coincident peak planning reserve margin (PRM_{ucap}) of 7.3 percent. Appendix 10B shows the IPL load and generating capability table before proposed resource additions.

10.1 Capacity Ratings

The generating unit ZRC capacity ratings for all IPL facilities can be found in Appendix 10C. Appendix 10C provides the detail for the IPL Resources line of the load and generating capability chart in Appendix 10B.

10.2 Generating Unit Data

Additional generating unit data from IPL's 2012 FERC Form 1 can be found in Appendix 10D. A comparison of retirement dates between the 2014 Resource Plan and previous resource plans is provided in Appendix 10E.

IPL Projected Load and Generating Capability Data
No Carbon Reference Case - After Resource Additions

(Carbon Cases very similar with wind beginning one year sooner)

IPL		2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030
Non-Coincident Peak		3121.3	3151.7	3179.1	3205.7	3232.8	3257.6	3284.6	3311.8	3339.3	3368.8	3398.5	3428.4	3458.6	3489.1	3519.9	3550.9
Coincident Peak	96.44%	3010.2	3039.5	3065.9	3091.5	3117.7	3141.6	3167.6	3193.9	3220.4	3248.8	3277.5	3306.3	3335.5	3364.9	3394.6	3424.5
Less Trans Loss Factor	2.49%	2935.2	2963.8	2989.5	3014.6	3040.0	3063.4	3088.8	3114.4	3140.2	3167.9	3195.8	3224.0	3252.4	3281.1	3310.0	3339.2
Demand Resources, Interruptible		263.3	265.4	267.5	269.6	271.8	274.0	276.2	278.4	280.6	282.8	285.1	287.4	289.7	292.0	294.3	296.7
Demand Resources, Direct Load Control		38.5	39.0	39.5	40.0	40.5	41.0	41.5	42.0	42.5	43.0	43.5	44.0	44.5	45.0	45.5	46.0
Interrupt and DLC less tran loss		301.8	304.4	307.0	309.6	312.3	315.0	317.7	320.4	323.1	325.8	328.6	331.4	334.2	337.0	339.8	342.7
Full Responsibility Sales																	
Full Responsibility Purchases																	
Adjusted Net Demand		2633.4	2659.4	2682.5	2705.0	2727.7	2748.4	2771.1	2794.0	2817.1	2842.1	2867.2	2892.6	2918.2	2944.1	2970.2	2996.5
Weighted LBA TM losses	2.50%	65.8	66.4	67.0	67.5	68.1	68.6	69.2	69.8	70.3	71.0	71.6	72.2	72.9	73.5	74.2	74.8
Planning Reserve Margin	7.30%	197.0	199.0	200.7	202.4	204.1	205.6	207.3	209.1	210.8	212.7	214.5	216.4	218.4	220.3	222.2	224.2
IPL Obligation		2896.2	2924.8	2950.2	2974.9	2999.9	3022.6	3047.6	3072.8	3098.3	3125.7	3153.4	3181.3	3209.5	3237.9	3266.6	3295.5
IPL Existing and Committed Resources		2502.4	2402.8	2344.2	2639.7	2641.6	2653.8	2667.2	2660.2	2660.2	2660.2	2656.1	2381.2	2381.2	2375.2	2228.8	2228.8
Existing Purchases		427.6	426.4	426.4	426.4	426.4	426.4	413.0	413.0	413.0	413.0	413.0	408.9	408.9	407.9	407.9	407.9
New Units:																	
One Year Capacity Purchases			100.0	200.0													
Wind Additions							14.1	28.2	42.3	56.4	70.5	84.6	98.7	112.8	126.9	141.0	155.1
Forced Solar (SES impacts)								4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9
2x1 Combined Cycle													573.8	573.8	573.8	573.8	573.8
Assumed wind PPA extensions							12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	12.7	
Total Resources		2929.9	2929.2	2970.6	3066.1	3068.0	3107.0	3125.9	3133.0	3147.1	3161.2	3171.2	3480.1	3494.2	3501.4	3369.0	3370.4
IPL Position (Long/short)		**33.7**	**4.5**	**20.4**	**91.2**	**68.1**	**84.3**	**78.4**	**60.2**	**48.9**	**35.5**	**17.8**	**298.9**	**284.8**	**263.5**	**102.4**	**74.9**

IPL Projected Load and Generating Capability Data
Reference Case - Before Resource Additions (other than MGS)

IPL		2014-2015	2015-2016	2016-2017	2017-2018	2018-2019	2019-2020	2020-2021	2021-2022	2022-2023	2023-2024	2024-2025	2025-2026	2026-2027	2027-2028	2028-2029	2029-2030
Non-Coincident Peak		3121.3	3151.7	3179.1	3205.7	3232.8	3257.6	3284.6	3311.8	3339.3	3368.8	3398.5	3428.4	3458.6	3489.1	3519.9	3550.9
Coincident Peak	96.44%	3010.2	3039.5	3065.9	3091.5	3117.7	3141.6	3167.6	3193.9	3220.4	3248.8	3277.5	3306.3	3335.5	3364.9	3394.6	3424.5
Less Trans Loss Factor	2.49%	2935.2	2963.8	2989.5	3014.6	3040.0	3063.4	3088.8	3114.4	3140.2	3167.9	3195.8	3224.0	3252.4	3281.1	3310.0	3339.2
Demand Resources, Interruptible		263.3	265.4	267.5	269.6	271.8	274.0	276.2	278.4	280.6	282.8	285.1	287.4	289.7	292.0	294.3	296.7
Demand Resources, Direct Load Control		38.5	39.0	39.5	40.0	40.5	41.0	41.5	42.0	42.5	43.0	43.5	44.0	44.5	45.0	45.5	46.0
Interrupt and DLC less tran loss		301.8	304.4	307.0	309.6	312.3	315.0	317.7	320.4	323.1	325.8	328.6	331.4	334.2	337.0	339.8	342.7
Full Responsibility Sales																	
Full Responsibility Purchases																	
Adjusted Net Demand		2633.4	2659.4	2682.5	2705.0	2727.7	2748.4	2771.1	2794.0	2817.1	2842.1	2867.2	2892.6	2918.2	2944.1	2970.2	2996.5
Weighted LBA TM losses	2.50%	65.8	66.4	67.0	67.5	68.1	68.6	69.2	69.8	70.3	71.0	71.6	72.2	72.9	73.5	74.2	74.8
Planning Reserve Margin	7.30%	197.0	199.0	200.7	202.4	204.1	205.6	207.3	209.1	210.8	212.7	214.5	216.4	218.4	220.3	222.2	224.2
IPL Obligation		2896.2	2924.8	2950.2	2974.9	2999.9	3022.6	3047.6	3072.8	3098.3	3125.7	3153.4	3181.3	3209.5	3237.9	3266.6	3295.5
IPL Resources		2929.9	2829.2	2770.6	3066.1	3068.0	3080.2	3080.2	3073.1	3073.1	3073.1	3069.0	2790.1	2790.1	2783.1	2636.7	2636.7
IPL Position (Long/short)		**33.7**	**(95.5)**	**(179.6)**	**91.2**	**68.1**	**57.5**	**32.6**	**0.4**	**(25.1)**	**(52.6)**	**(84.3)**	**(391.2)**	**(419.4)**	**(454.8)**	**(630.0)**	**(658.9)**

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

[TRADE SECRET DATA BEGINS

Section 10
Appendix 10C
1 Page

IPL Planning Resource Credit (ZRC) Ratings

TRADE SECRET DATA ENDS]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Interstate Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Prairie Creek 1,3* (b)	Plant Name: *Prairie Creek 4* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1958	1968
4	Year Last Unit was Installed	1997	1968
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	64.63	148.75
6	Net Peak Demand on Plant - MW (60 minutes)	43	125
7	Plant Hours Connected to Load	8784	6209
8	Net Continuous Plant Capability (Megawatts)	33	112
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	59	59
12	Net Generation, Exclusive of Plant Use - KWh	94334000	464543000
13	Cost of Plant: Land and Land Rights	8548	160173
14	Structures and Improvements	0	26720222
15	Equipment Costs	62879621	144551589
16	Asset Retirement Costs	3864626	1541892
17	Total Cost	66752795	172973876
18	Cost per KW of Installed Capacity (line 17/5) Including	1032.8454	1162.8496
19	Production Expenses: Oper, Supv, & Engr	0	470671
20	Fuel	0	16348342
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	3401776
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	-3055834
25	Electric Expenses	0	855991
26	Misc Steam (or Nuclear) Power Expenses	0	739278
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	240690
30	Maintenance of Structures	0	143647
31	Maintenance of Boiler (or reactor) Plant	0	1659735
32	Maintenance of Electric Plant	0	485774
33	Maintenance of Misc Steam (or Nuclear) Plant	0	647711
34	Total Production Expenses	0	21937781
35	Expenses per Net KWh	0.0000	0.0472

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)				Total Prairie	Coal	Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)				Creek Fuels	Ton	Mcf
38	Quantity (Units) of Fuel Burned	0	0	0	0	391020	468644
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	8574	1018
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	36.410	3.730
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	36.000	3.750
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	2.100	3.680
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.027	0.047
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	12852.000	12852.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Interstate Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Sutherland* (b)		Plant Name: *Marshalltown* (c)	
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam		Gas Turbine	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional		Conventional	
3	Year Originally Constructed	1955		1977	
4	Year Last Unit was Installed	1961		1978	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	119.10		189.00	
6	Net Peak Demand on Plant - MW (60 minutes)	104		108	
7	Plant Hours Connected to Load	5073		658	
8	Net Continuous Plant Capability (Megawatts)	108		165	
9	When Not Limited by Condenser Water	0		0	
10	When Limited by Condenser Water	0		0	
11	Average Number of Employees	22		22	
12	Net Generation, Exclusive of Plant Use - KWh	222603302		30067840	
13	Cost of Plant: Land and Land Rights	173560		0	
14	Structures and Improvements	13933440		188716	
15	Equipment Costs	124660344		25460838	
16	Asset Retirement Costs	1510451		0	
17	Total Cost	140277795		25649554	
18	Cost per KW of Installed Capacity (line 17/5) Including	1177.8152		135.7119	
19	Production Expenses: Oper, Supv, & Engr	130892		-68	
20	Fuel	7551695		9702127	
21	Coolants and Water (Nuclear Plants Only)	0		0	
22	Steam Expenses	1316691		1328	
23	Steam From Other Sources	0		0	
24	Steam Transferred (Cr)	0		0	
25	Electric Expenses	493165		51228	
26	Misc Steam (or Nuclear) Power Expenses	416054		42870	
27	Rents	0		0	
28	Allowances	0		0	
29	Maintenance Supervision and Engineering	105882		-72	
30	Maintenance of Structures	140877		20580	
31	Maintenance of Boiler (or reactor) Plant	557004		1696	
32	Maintenance of Electric Plant	389593		97417	
33	Maintenance of Misc Steam (or Nuclear) Plant	528077		7641	
34	Total Production Expenses	11629930		9924747	
35	Expenses per Net KWh	0.0522		0.3301	

Line No.	Item (a)	(b)				(c)	
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal		Gas		Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Ton		Mcf		Barrel	
38	Quantity (Units) of Fuel Burned	84977	0	1010536	0	74140	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9143	0	1023	0	138500	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	37.700	0.000	4.530	0.000	132.890	0.000
41	Average Cost of Fuel per Unit Burned	31.480	0.000	4.530	0.000	130.860	0.000
42	Average Cost of Fuel Burned per Million BTU	1.720	0.000	4.430	0.000	22.500	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.020	0.000	0.052	0.000	0.323	0.000
44	Average BTU per KWh Net Generation	11625.000	0.000	11625.000	0.000	14343.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Interstate Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Centerville* (b)	Plant Name: *Burlington* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1990	1968
4	Year Last Unit was Installed	1990	1968
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	54.00	211.95
6	Net Peak Demand on Plant - MW (60 minutes)	39	213
7	Plant Hours Connected to Load	134	7192
8	Net Continuous Plant Capability (Megawatts)	49	190
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	1	39
12	Net Generation, Exclusive of Plant Use - KWh	2393100	1163795000
13	Cost of Plant: Land and Land Rights	19150	81312
14	Structures and Improvements	262557	12803578
15	Equipment Costs	5580865	97532923
16	Asset Retirement Costs	0	311632
17	Total Cost	5862572	110729445
18	Cost per KW of Installed Capacity (line 17/5) Including	108.5661	522.4319
19	Production Expenses: Oper, Supv, & Engr	-258	228391
20	Fuel	1421648	20008663
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	113	1271235
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	15445	497986
26	Misc Steam (or Nuclear) Power Expenses	5131	516920
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	-274	232399
30	Maintenance of Structures	13508	525726
31	Maintenance of Boiler (or reactor) Plant	113	962997
32	Maintenance of Electric Plant	46207	211172
33	Maintenance of Misc Steam (or Nuclear) Plant	27999	291407
34	Total Production Expenses	1529632	24746896
35	Expenses per Net KWh	0.6392	0.0213

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		Oil		Coal	Oil	Gas
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		Barrel		Ton	Barrel	Mcf
38	Quantity (Units) of Fuel Burned	0	11219	0	747465	0	16290
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	138500	0	8417	0	1025
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	127.310	0.000	26.710	139.780	5.330
41	Average Cost of Fuel per Unit Burned	0.000	126.720	0.000	26.500	0.000	5.330
42	Average Cost of Fuel Burned per Million BTU	0.000	21.780	0.000	1.570	0.000	5.200
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.594	0.000	0.017	0.000	0.056
44	Average BTU per KWh Net Generation	0.000	27270.000	0.000	10826.000	0.000	10826.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Interstate Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Dubuque* (b)	Plant Name: *Lansing* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Steam
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1904	1957
4	Year Last Unit was Installed	1959	1977
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	66.25	312.00
6	Net Peak Demand on Plant - MW (60 minutes)	68	262
7	Plant Hours Connected to Load	3772	6670
8	Net Continuous Plant Capability (Megawatts)	59	270
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	16	50
12	Net Generation, Exclusive of Plant Use - KWh	82130200	1136805754
13	Cost of Plant: Land and Land Rights	58147	168534
14	Structures and Improvements	4233766	29056023
15	Equipment Costs	29252487	346154353
16	Asset Retirement Costs	1606057	1674626
17	Total Cost	35150457	377053536
18	Cost per KW of Installed Capacity (line 17/5) Including	530.5729	1208.5049
19	Production Expenses: Oper, Supv, & Engr	33434	394723
20	Fuel	4181936	34069208
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	1589363
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	1146207	563899
26	Misc Steam (or Nuclear) Power Expenses	290345	618651
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	19951	327695
30	Maintenance of Structures	18788	140319
31	Maintenance of Boiler (or reactor) Plant	0	1734534
32	Maintenance of Electric Plant	346750	181868
33	Maintenance of Misc Steam (or Nuclear) Plant	304190	816182
34	Total Production Expenses	6341601	40436442
35	Expenses per Net KWh	0.0772	0.0356

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)			Gas	Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)			Mcf	Ton	Barrel	
38	Quantity (Units) of Fuel Burned	0	0	1248068	760752	9003	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	1023	8783	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	3.351	41.740	131.690	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	3.351	42.420	130.760	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	3.274	2.415	22.237	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.051	0.029	0.262	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	15546.000	11802.000	11802.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Interstate Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Montgomery* (b)			Plant Name: *Lime Creek* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1974			1991		
4	Year Last Unit was Installed	1974			1991		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			90.10		
6	Net Peak Demand on Plant - MW (60 minutes)	0			63		
7	Plant Hours Connected to Load	0			39		
8	Net Continuous Plant Capability (Megawatts)	0			70		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	-97320			889400		
13	Cost of Plant: Land and Land Rights	14512			0		
14	Structures and Improvements	0			2171344		
15	Equipment Costs	0			23250388		
16	Asset Retirement Costs	48807			47003		
17	Total Cost	63319			25468735		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			282.6719		
19	Production Expenses: Oper, Supv, & Engr	0			-32		
20	Fuel	0			502123		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			-171		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2706			4179		
26	Misc Steam (or Nuclear) Power Expenses	594			22991		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			-34		
30	Maintenance of Structures	228			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	3683			21626		
33	Maintenance of Misc Steam (or Nuclear) Plant	534			0		
34	Total Production Expenses	7745			550682		
35	Expenses per Net KWh	-0.0796			0.6192		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)					Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)					Barrel	
38	Quantity (Units) of Fuel Burned	0	0	0	0	4480	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	140000	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	125.640	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	112.080	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	19.061	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.565	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	29618.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Interstate Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Red Cedar* (d)			Plant Name: (e)			Plant Name: *Emery* (f)			Line No.
		Gas Turbine						Gas Turbine	1
		Conventional						Combined Cycle Steam	2
		1996						2004	3
		1996						2004	4
		22.50			0.00			602.82	5
		20			0			601	6
		21			0			2736	7
		23			0			596	8
		0			0			0	9
		0			0			0	10
		0			0			16	11
		-240000			0			868237959	12
		75177			0			607541	13
		95587			0			58855000	14
		14061532			0			353156649	15
		0			0			52440	16
		14232296			0			412671630	17
		632.5465			0			684.5686	18
		-481			0			1854275	19
		21498			0			24257071	20
		0			0			0	21
		-109			0			28195	22
		0			0			0	23
		0			0			0	24
		12661			0			120	25
		25199			0			631287	26
		0			0			0	27
		0			0			0	28
		-500			0			-11911	29
		7858			0			133	30
		11			0			0	31
		34538			0			4217233	32
		-79			0			0	33
		100596			0			30976403	34
		-0.4192			0.0000			0.0357	35
		Gas					Oil	Gas	36
		Mcf					Barrel	Mcf	37
0	0	4155	0	0	0	0	535	6232879	38
0	0	1017	0	0	0	0	138500	1026	39
0.000	0.000	5.170	0.000	0.000	0.000	0.000	0.000	3.880	40
0.000	0.000	5.170	0.000	0.000	0.000	0.000	85.040	3.880	41
0.000	0.000	5.090	0.000	0.000	0.000	0.000	14.620	3.790	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.108	0.028	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	7367.000	7367.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Interstate Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Ottumwa* (d)	Plant Name: *George Neal # 3* (e)	Plant Name: *Grinnell* (f)	Line No.
Steam	Steam	Gas Turbine	1
Conventional	Conventional	Conventional	2
1981	1975	1990	3
1981	1975	1991	4
348.41	153.95	47.60	5
340	149	43	6
6376	6754	0	7
324	0	50	8
0	140	0	9
0	140	0	10
37	21	0	11
1605821000	756138000	1661950	12
856123	331	25000	13
45029568	5078324	235893	14
193367077	53963126	5778579	15
-300638	0	0	16
238952130	59041781	6039472	17
685.8360	383.5127	126.8797	18
226727	698551	13	19
35699058	12027062	182225	20
0	0	0	21
1477555	470908	-392	22
0	0	0	23
0	0	0	24
942182	204060	20190	25
501266	852089	7449	26
0	0	0	27
0	0	0	28
219454	742210	14	29
149538	197164	2087	30
1435014	1065834	322	31
611624	441699	9528	32
574356	270938	3494	33
41836774	16970515	224930	34
0.0261	0.0224	0.1353	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Oil		Coal		Gas			Gas	36
Ton	Barrel		Ton		Mcf			Mcf	37
1029007	9965	0	461420	0	38364	0	0	43768	38
8396	140000	0	8635	0	1018	0	0	1021	39
32.940	130.400	0.000	25.400	0.000	5.240	0.000	0.000	4.160	40
32.060	131.510	0.000	24.860	0.000	5.240	0.000	0.000	4.160	41
1.910	22.370	0.000	1.440	0.000	5.150	0.000	0.000	4.080	42
0.021	0.242	0.000	0.015	0.000	0.055	0.000	0.000	0.110	43
10797.000	10797.000	0.000	10591.000	0.000	10591.000	0.000	0.000	26878.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Interstate Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Burlington CT* (d)	Plant Name: (e)	Plant Name: *M. L. Kapp* (f)	Line No.
Gas Turbine		Steam	1
Conventional		Conventional	2
1994		1967	3
1996		1967	4
78.92	0.00	218.45	5
0	0	205	6
0	0	4113	7
60	0	200	8
0	0	0	9
0	0	0	10
0	0	35	11
1180000	0	531353000	12
115976	0	52232	13
33540	0	10521583	14
17414863	0	95319850	15
0	0	858190	16
17564379	0	106751855	17
222.5593	0	488.6787	18
0	0	206675	19
131321	0	13777978	20
0	0	0	21
0	0	954283	22
0	0	0	23
0	0	0	24
965	0	312039	25
2209	0	468221	26
0	0	0	27
0	0	0	28
0	0	214932	29
33293	0	72249	30
0	0	1509431	31
30038	0	375705	32
0	0	379831	33
197826	0	18271344	34
0.1676	0.0000	0.0344	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
	Oil	Gas				Coal		Gas	36
	Barrel	Mcf				Ton		Mcf	37
0	13	29171	0	0	0	350588	0	34863	38
0	140000	1034	0	0	0	8471	0	1000	39
0.000	164.050	4.430	0.000	0.000	0.000	35.640	0.000	4.913	40
0.000	164.050	4.430	0.000	0.000	0.000	27.200	0.000	4.913	41
0.000	27.790	4.280	0.000	0.000	0.000	2.196	0.000	4.913	42
0.000	0.712	0.110	0.000	0.000	0.000	0.025	0.000	0.055	43
0.000	25633.000	25633.000	0.000	0.000	0.000	11244.000	0.000	11244.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Interstate Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Fox Lake* (d)	Plant Name: *George Neal #4* (e)	Plant Name: *Louisa* (f)	Line No.
Steam	Steam	Steam	1
Conventional	Conventional	Conventional	2
1950	1979	1983	3
1962	1979	1983	4
93.10	164.70	32.40	5
80	169	31	6
674	8314	8543	7
91	0	0	8
0	165	30	9
0	165	30	10
11	23	4	11
21277240	1214511000	224716120	12
29665	155541	16828	13
3464311	13106494	5970494	14
22655100	83827115	29045007	15
1167405	0	0	16
27316481	97089150	35032329	17
293.4101	589.4909	1081.2447	18
27827	726585	110408	19
1035767	18687232	3626358	20
0	0	0	21
574221	695554	170650	22
0	0	0	23
0	0	0	24
189094	301407	75241	25
169946	934293	157823	26
0	0	0	27
0	0	0	28
29499	771997	117308	29
2199	210889	28166	30
42371	1278896	440437	31
107446	516166	71823	32
226268	280868	52626	33
2404638	24403887	4850840	34
0.1130	0.0201	0.0216	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
		Gas	Coal	Oil		Coal	Oil	Gas	36
		Mcf	Ton	Barrel		Ton	Barrel	Mcf	37
0	0	276690	724255	3730	0	137594	2	2649	38
0	0	1029	8690	136566	0	8485	137058	1015	39
0.000	0.000	3.743	24.890	136.030	0.000	25.410	130.780	4.950	40
0.000	0.000	3.743	24.590	133.520	0.000	25.250	79.870	4.950	41
0.000	0.000	3.639	1.415	23.278	0.000	1.488	13.875	4.877	42
0.000	0.000	0.049	0.015	0.242	0.000	0.016	0.144	0.051	43
0.000	0.000	13381.000	10382.000	10382.000	0.000	10403.000	10403.000	10403.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Interstate Power and Light Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2012/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Whispering Willow* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Wind Energy			1
Conventional			2
2009			3
2009			4
199.65	0.00	0.00	5
199	0	0	6
7532	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
2	0	0	11
579025000	0	0	12
14292413	0	0	13
58260314	0	0	14
344189792	0	0	15
13232645	0	0	16
429975164	0	0	17
2153.6447	0	0	18
528662	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
2137	0	0	26
588890	0	0	27
0	0	0	28
0	0	0	29
9169	0	0	30
0	0	0	31
73441	0	0	32
8235719	0	0	33
9438018	0	0	34
0.0163	0.0000	0.0000	35

									Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Interstate Power and Light Company	(1) X An Original (2) __ A Resubmission	/ /	2012/Q4

FOOTNOTE DATA

Schedule Page: 402 Line No.: 11 Column: b

Employees reported at Prairie Creek Units 1 and 3 are the same as those reported for Prairie Creek Unit 4, Page 402, Column (c).

Schedule Page: 402 Line No.: 19 Column: b

Production Expenses for Prairie Creek Units 1 and 3 are included in Prairie Creek Unit 4, Page 402, Column (c).

Schedule Page: 403.1 Line No.: 2 Column: d

The Ottumwa Generating Station (OGS) is operated by Interstate Power and Light Company, and owned jointly by the Company and MidAmerican Energy Company with the participants having undivided ownership's of 48% and 52%, respectively.

Schedule Page: 403.1 Line No.: 2 Column: e

George Neal Station Unit #3 is operated by MidAmerican Energy Company and owned jointly by the Company and MidAmerican Energy with the participants having undivided ownerships of 28% and 72%, respectively.

Schedule Page: 403.1 Line No.: 2 Column: f

Grinnell Generating Station was installed for peak load service. Two gas turbines were installed in 1991. Cost of plant (Line 17) includes both turbines.

Schedule Page: 403.1 Line No.: 5 Column: d

Ottumwa installed capacity of 348.41 MW represents Interstate Power and Light Company's 48% interest. Lines 6, and 8 through 44 are also stated in the Company's 48% portion.

Schedule Page: 403.1 Line No.: 5 Column: e

George Neal #3 installed capacity of 153.95 MW represents Interstate Power and Light Company's 28% interest. Lines 6, and 9 through 44 are also stated in the Company's 28% portion.

Schedule Page: 403.1 Line No.: 6 Column: f

Net peak demand for each of the two units at Grinell Gas Turbine location are as follows: Unit #1 - 25 and Unit #2 - 18.

Schedule Page: 403.1 Line No.: 7 Column: f

Plant hours connected to load for each of the two units at Grinell Gas Turbine location are as follows: Unit #1 - 85.2 and Unit #2 - 73.4.

Schedule Page: 402.1 Line No.: 11 Column: c

Marshalltown Gas Turbine employees are the same as those reported on Page 402.1, Line 11, Column (b), Sutherland.

Schedule Page: 403.2 Line No.: 6 Column: d

Net peak demand for each of the four units at Burlington Gas Turbine location are as follows: Unit #1 - 16, Unit #2 - 14, Unit #3 - 13, Unit #4 - 15.

Schedule Page: 403.2 Line No.: 7 Column: d

Plant hours connected to load for each of the four units at Burlington Gas Turbine location are as follows: Unit #1 - 47.1, Unit #2 - 24.2, Unit #3 - 46.3, Unit #4 - 34.3.

Schedule Page: 402.2 Line No.: 11 Column: b

Centerville Gas Turbine shares an employee that is based at Ottumwa Generating Station, Page 403.1, Column (d).

Schedule Page: 403.3 Line No.: 2 Column: e

George Neal Station Unit #4 is operated by MidAmerican Energy Company. Interstate Power and Light Company has a joint ownership portion of 25.695% of Neal Unit #4.

Schedule Page: 403.3 Line No.: 2 Column: f

Louisa Generating Station is operated by MidAmerican Energy Company. Interstate Power and Light Company has a joint ownership portion of 4.0% of Louisa Generating Station.

Schedule Page: 403.3 Line No.: 5 Column: e

George Neal #4 installed capacity of 164.70 MW represents Interstate Power and Light Company's 25.695% interest. Lines 6, and 9 through 44 are also stated in the Company's 25.695% portion.

Schedule Page: 403.3 Line No.: 5 Column: f

Louisa Generating Station installed capacity of 32.4 MW represents Interstate Power and Light Company's 4% interest. Lines 6, and 9 through 44 are also stated in the Company's 4% portion.

Schedule Page: 402.4 Line No.: 5 Column: b

Montgomery Generating Station was retired in place in December 2012. Installed capacity was 28.80 MW.

Schedule Page: 402 Line No.: 36 Column: c1

Fuels for Prairie Creek Units 1 and 3 are included in Prairie Creek Unit 4, column (c).

IPL IRP Planned Retirement Assumptions

	2010 IRP Study period 2010-2025 Retire assumption	2012 IRP / Baseload Diversification Study Study Period 2012-2027 Retire assumption	2014 IRP Study Period 2014-2029 Retire assumption
Tier 1			
Lansing #4	no planned retire date	no planned retire date	no planned retire date
Ottumwa	no planned retire date	no planned retire date	no planned retire date
Louisa	no planned retire date	no planned retire date	no planned retire date
Neal 25 04	no planned retire date	no planned retire date	no planned retire date
Neal #3	no planned retire date	no planned retire date	no planned retire date

Tier 2

[TRADE SECRET DATA BEGINS

TRADE SECRET DATA ENDS]

Tier 3			
Dubuque #3	12/31/2014	12/31/2014	12/31/2015
Dubuque #4	12/31/2014	12/31/2014	12/31/2015
Sutherland 1	12/31/2014	12/31/2016	12/31/2016
Owned Wind			
Whispering Willow East	no planned retire date	no planned retire date	no planned retire date

	2010 IRP Study period 2010-2025 Retire assumption	**2012 IRP / Baseload Diversification Study** Study Period 2012-2027 Retire assumption	**2014 IRP** Study Period 2014-2029 Retire assumption
Gas/Oil/Other			
Emery	no planned retire date	no planned retire date	no planned retire date
Fox Lake #3G	no planned retire date	12/31/2016	12/31/2016
[TRADE SECRET DATA BEGINS			TRADE SECRET DATA ENDS]
Lime Creek 1	no planned retire date	no planned retire date	no planned retire date
Lime Creek 2	no planned retire date	no planned retire date	no planned retire date
[TRADE SECRET DATA BEGINS			TRADE SECRET DATA ENDS]
Sutherland CT1	no planned retire date	no planned retire date	12/31/2027
Sutherland CT2	no planned retire date	no planned retire date	12/31/2027
Sutherland CT3	no planned retire date	no planned retire date	12/31/2027
[TRADE SECRET DATA BEGINS			TRADE SECRET DATA ENDS]
Red Cedar Cogen	no planned retire date	no planned retire date	12/31/2026
Prairie Creek 1	no planned retire date	no planned retire date	no planned retire date
[TRADE SECRET DATA BEGINS			TRADE SECRET DATA ENDS]

PPA

	2010 IRP Study period 2010-2025 Retire assumption	**2012 IRP / Baseload Diversification Study** Study Period 2012-2027 Retire assumption	**2014 IRP** Study Period 2014-2029 Retire assumption
DAEC Purchase (2012)	renews in 2014 through study period	renews 1/1/2014-12/31/2025	renews 1/1/2014-12/31/2025 and continues through license life (2034)
Wind IPW Cerro Gordo	12/31/2023	12/31/2023	12/31/2023
Wind IPW Flying Cloud	renewed/ replaced 2019	renewed/ replaced 2019	renewed/ replaced 2019-2028
Wind IPW Bingham	12/31/2020	12/31/2020	12/31/2020
Wind IPW Adams	12/31/2018	12/31/2018	12/31/2018
Wind IES Buena Vista	renewed/ replaced 2019	renewed/ replaced 2019	renewed/ replaced 2019-2028
Wind IES Hancock	no planned retire date	no planned retire date	12/31/2027
Wind Hardin Hilltop	12/31/2026	12/31/2026	12/31/2026
100 MW PPA Wind*	no planned retire date	n/a	n/a

* 100 MW PPA Wind associated with DAEC renewal in 2010 IRP. Did not come to fruition as part of negotiations.

Annual Forecast Requirements - Written Responses

7610.0310 Content of Historical Data and Forecast

I. The utility's method of determining its reserve system margin and the appropriateness of the margin.

Alliant Energy – Interstate Power and Light (IPL), as a load serving entity (LSE) subject to the Resource Adequacy (aka Module E-1) provisions of the MISO tariff, is obligated to provide capacity to serve its own load coincident with the MISO peak, plus a Planning Reserve Margin (PRM). For the 2013/2014 Planning Year, which runs from June to May, the required Planning Reserve Margin is 6.2% (on an unforced capacity basis, UCAP). For future Planning Years in this filing, IPL used the projected estimated PRM found on page 14 of the MISO Planning Year 2013 LOLE Study Report:

Table 2-4: Estimated PRM for 2013-2022
(red values are calculated and black values are interpolated)

Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
PRM_{ICAP} (Results Ignoring Congestion)	14.2%	14.1%	14.0%	13.9%	13.8%	13.7%	13.7%	13.6%	13.5%	13.4%
PRM_{UCAP} (Results Ignoring Congestion)	6.2%	6.2%	6.1%	6.1%	6.0%	6.0%	6.0%	6.0%	5.9%	5.9%

7610.0320 Forecast Documentation

Subpart 1. The **forecast methodologies** for the energy and demand forecasts are detailed below.

1.1 Energy Forecast

IPL's energy forecast is based on class level regression models for the long and short-term, adjusted for consistency with recent trends, as well as estimates of other sales, large industrial sales, and losses. The statistical models were created in July 2011, with the forecast updated in March 2013. DSM is included implicitly in the forecast by inclusion in the historical loads used to develop forecasted sales.

1.1.1. Short Term Residential Energy

The short term Residential sales are modeled using billing month observations of residential use per customer. The variables used and their descriptions are as follows:

Actual Residential Heating Degree Days (wgtHDD): The sales weighted average of the route level base 65 HDD for the billing month.
Actual Residential Cooling Degree Days (wgtCDD): The sales weighted average of the route level base 65 CDD for billing month.
IA Real Personal Income (IA_RPI_M): Monthly observations of IA real personal income.
Common Residential Definition (ComDef): An indicator variable for January 2005 and beyond. This variable is necessary due to an increase in the number of customers in the residential class resulting from an internal inquiry into the definition of a residential customer.

Monthly Indicators (Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec): Variables that take the value of one (1) during the designated month to indicate systematic fluctuation in sales not related to the weather or the economy, and zero (0) otherwise.

The model equation is as follows:
(Residential kWh/customer) =340.145+ (0.265*(wgtHDD)) +(1.498*(wgtCDD)) + (0.003*(IA_RPI_M)) – (20.575*(ComDef)) –(104.710*(Feb)) –(127.541*(Mar)) – (129.980*(Apr)) –(128.254*(May)) – (87.386*(Jun)) –(19.166*(Jul)) +(4.114*(Aug)) – (17.969*(Sep)) – (79.273*(Oct)) – (79.848*(Nov)) – (19.402 *(Dec)) + e
where e is an error term.

The model parameters are as follows:

Table 1.1.1.1

Short Term IPL Residential Sales Model Parameters

Variable	Coefficient	T-Ratio	Prob.>|T|
CONST	340.145	6.20	0%
wgtHDD	0.265	14.21	0%
wgtCDD	1.498	23.56	0%
IA_RPI_M	0.003	4.82	0%
ComDef	-20.575	-3.03	0%
Feb	-104.710	-11.66	0%
Mar	-127.541	-11.98	0%
Apr	-129.980	-7.71	0%
May	-128.254	-5.83	0%
Jun	-87.386	-3.33	0%
Jul	-19.166	-0.64	53%
Aug	4.114	-0.13	89%
Sep	-17.969	-0.63	53%
Oct	-79.273	-3.25	0%
Nov	-79.848	-4.27	0%
Dec	-19.402	-1.72	9%
R2= 0.9804 Adj. R2=0.9777			

1.1.2. Short Term Commercial Energy

The short term Commercial sales are modeled using billing month observations of commercial use per customer. The variables used and their descriptions are as follows.

Actual Commercial Heating Degree Days (wgtHDD): The sales weighted average of the route level base 65 HDD for the billing month.
Actual Commercial Cooling Degree Days (wgtCDD): The sales weighted average of the route level CDD for the billing month.
IA Real Personal Income (IA_RPI_M): Monthly observations of IA real personal income.
Monthly Indicators (Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec): Variables that take the value of one (1) during the designated month to indicate systematic fluctuation in sales not related to the weather or the economy, and zero (0) otherwise.

The model equation is as follows:

(Commercial kWh/customer) =1277.690 + (0.491*(wgtHDD)) + (3.185*(wgtCDD)) + (0.023*(IA_RPI_M)) – (274.255*(Feb)) – (396.731*(Mar)) – (355.557*(Apr)) – (248.490*(May)) – (26.192*(Jun)) + (51.117*(Jul)) + (78.472*(Aug)) + (236.747*(Sep)) + (103.358*(Oct)) – (16.369*(Nov)) + (135.374*(Dec)) + e
where e is an error term.

The model parameters are as follows:

Table 1.1.2.1
Short Term IPL Commercial Sales Model Parameters

Variable	Coefficient	T-Ratio	Prob.>|T|
CONST	1,227.690	6.77	0%
wgtHDD	0.491	5.32	0%
wgtCDD	3.185	10.10	0%
IA_RPI_M	0.023	14.55	0%
Feb	-274.255	-6.17	0%
Mar	-396.731	-7.30	0%
Apr	-355.557	-4.18	0%
May	-248.490	-2.26	3%
Jun	-26.192	-0.20	84%
Jul	51.117	0.35	73%
Aug	78.472	0.52	61%
Sep	236.747	1.70	9%
Oct	103.358	0.87	39%
Nov	-16.369	-0.18	86%
Dec	135.374	2.44	2%
R^2=0.9231 Adj. R^2= 0.9134			

1.1.3.1 Short Term Industrial Energy

The short term Industrial sales are modeled using billing month observations of use per customer for the Industrial class. The variables used and their descriptions are as follows:

Actual Industrial Cooling Degree Days (wgtCDD): The sales weighted average of the route level CDD for the billing month.
Industrial Definition (IndDef): An indicator variable that takes the value of one (1) for the period from December 2004 onward based on an increase in the number of customers following an analysis on the definition of an industrial customer and zero (0) otherwise.
IPL Indicator (IPL): An indicator that use per customer is influenced by the merger that created the IPL system that takes the value of one (1) and zero (0) otherwise.
Monthly Indicator (Feb, Mar, Apr, May, Jun, Jul, Aug, Sep, Oct, Nov, Dec): A variable that takes the value of one (1) during the designated month to indicate systematic fluctuation in sales not related to the weather or economy.

(Industrial kWh/customer) =176,239 + (92.646*(wgtCDD)) – (2,869.761*(IPL)) – (22,593*(IndDef)) – (3,413.091*(Feb)) – (3,883.445*(Mar)) – (8,282.719*(Apr)) – (5,023.580*(May)) – (7,085.287*(Jun)) –(10,859*(Jul)) –(7,172.199*(Aug)) + (862.103*(Sep)) + (2,675.790*(Oct)) – (1,135.270 * (Nov)) + (4,994.614 *(Dec)) + e
where e is an error term.

The model parameters are as follows:

Table 1.1.3.1
Short Term IPL Industrial Sales Model Parameters

Variable	Coefficient	T-Ratio	Prob.>|T|
CONST	176,239	69.38	0%
wgtCDD	92.646	4.49	0%
IPL	-2,869.761	-1.37	17%
INDDef	-22,593	-13.42	0%
Feb	-3,413.091	-1.11	27%
Mar	-3,883.445	-1.27	21%
Apr	-8,282.719	-2.71	1%
May	-5,023.580	-1.61	11%
Jun	-7,085.287	-1.74	8%
Jul	-10,859	-1.95	5%
Aug	-7,172.199	-1.26	21%
Sep	862.103	0.22	83%
Oct	2,675.790	0.94	40%
Nov	-1,135.270	-0.36	72%
Dec	4,994.614	1.59	11%
R^2=0.806 Adj. R^2=0.782			

1.1.4. Short and Long Term IPL Large Industrial Sales

The Large Industrial class consists of IPL's largest industrial customers. These customers face large, and usually planned changes in their energy use. Therefore, the Large Industrial's sales forecast relies on communication with the customer account representatives and examination of historical sales.

1.1.5. Short and Long Term IPL Other Sales and Losses

The Other sales forecast includes the Municipal, Other Public Authorities, Interdepartmental, and Street Lighting rates. These classes are not formally modeled as they consist of less than 4% of total sales. The forecast for these classes are made based on recent historical data and on any known contract changes.

1.1.6. Long Term IPL Residential

For Residential sales, the model is based on annual observations. The independent variables used and their descriptions are as follows:

Cooling Degree Days (CDD) is a measure of annual cooling load.

Real Price of Residential Electricity (RPRICE) is the annual price of electricity in chain-weighted 2005 dollars.

Iowa Gross State Product (IAGSP) is a measure of economic activity in an area that approximates the service territory in chain-weighted 2005 dollars.

The model equation is as follows:

(Residential use per customer, (MWH*1,000/ customer)) =7,929+ (0.983*(CDD)) – (1,493*(RPRICE)) + (18.8*(IAGSP)) +e
where e is an error term.

The model parameters are as follows:

Table 1.1.6.1
Long Term IPL Residential Sales Model Parameters

Variable	Coefficient	T-Ratio	Prob.>|T|
CONST	7,929	18.93	0%
CDD	0.983	6.55	0%
RPRICE	-1,493	-5.23	0%
IAGSP	18.8	11.96	0%
R^2=0.926 Adj. R^2=0.917			

1.1.7. Long Term IPL Commercial Sales

For Commercial sales, the model is based on annual observations. The independent variables used and their descriptions are as follows:
<u>Real Price of Electricity (CPRICE)</u> is the approximate annual price of electricity, in chain-weighted 2005 dollars, for the commercial class.
<u>Iowa Gross State Product (IAGSP)</u> is a measure of economic activity in an area that approximates the service territory in chain-weighted 2005 dollars.

The model equation is as follows:
(Commercial MWh/Customer)=26.3 – (10.2*(CPRICE)) + (0.247*(IAGSP)) + e
where e is an error term.

The model parameters are as follows:

Table 1.1.7.1
Long Term IPL Commercial Sales Model Parameters

Variable	Coefficient	T-Ratio	Prob.>|T|
Constant	26.3	11.3	0%
CPRICE	-10.2	-6.99	0%
IAGSP	0.247	20.5	0%
R^2= 0.985 Adj. R^2=0.984			

1.1.8 Long Term IPL Industrial Sales

For Industrial sales, the model is based on annual observations. Industrial sales are sales to the Industrial Revenue Class less the sales to the Large Industrial class. The independent variables used and their descriptions are as follows:

<u>Iowa Gross State Product (IAGSP)</u> is a measure of economic activity in an area that approximates the service territory in chain-weighted 2005 dollars.
<u>Real Industrial Price of Electricity (IPRICE)</u> is the annual price of electricity in chain-weighted 2005 dollars, for the industrial class less large industrial customers.

The model equation is as follows:
(Industrial MWh/customer) = 3,619 – (2,689*(IPRICE)) + (1.35*(IAGSP)) + e
where e is an error term.

The model parameters are as follows:

Table 1.1.8.1
Long Term IPL Industrial Sales Model Parameters

Variable	Coefficient	T-Ratio	Prob.>|T|
Constant	3,619	21.0	0%
IPRICE	-2,689	-16.6	0%
IAGSP	1.35	1.27	21.5%
R^2= 0.953 Adj. R^2=0.949			

1.2 Confidence Intervals

Each statistically modeled class has its own confidence interval. These are presented below in table 1.2.1.

Table 1.2.1
IPL Sales Model 95% Confidence Intervals

Year	Residential +/- MWH	Commercial +/- MWH	Industrial +/- MWH
2013	159	164	409
2014	175	176	430
2015	179	183	443
2016	181	188	453
2017	184	192	460
2018	185	195	466
2019	187	199	474
2020	189	203	480
2021	191	206	487
2022	192	208	491
2023	193	211	497
2024	196	216	505
2025	198	220	514
2026	200	224	521
2027	202	228	529

1.3 Summer Peak Forecast

The current IPL summer peak forecast is developed using a regression model to predict the long-term growth in the system firm peak requirements. No explicit adjustments for DSM are taken since the impacts of current programs are captured in the historical data and future programs impacts are currently anticipated to be consistent current programs.

The peak model is the sum of the forecasted firm demand for eleven IPL large customers, large changes, and the IPL Basic model. Large Customer forecasts and large changes are based on personal discussions with representatives from IPL's large customers tempered by IPL's experience and evaluation of any information provided.

The IPL Basic model is the demand of the remaining IPL retail customers. IPL Basic is forecast using an econometric regression model. Total firm demand is divided by the number of customers to come up with the average demand per customer. This is used for the dependent variable in the regression equation. Descriptions of the independent variables follow:

Real Personal Income Per Capita (PIPC): Real per capita personal income in Iowa in 2005 dollars.
Real Summer Price of Electricity (PERSA): The IPL price of electricity during the June-Aug in 2005 dollars.
Temperature Humidity Index (THIC): This index is based on temperature and humidity on peak day, the previous two days, and the accumulated cooling degree days index over the four weeks leading up to the peak. This variable is included in the regression model rather than weather-normalizing the data beforehand.
Union Electric Indicator (UE): An indicator variable that recognizes that the addition of the former UE territory would impact the rate of growth of the IPL system peak.

The coefficient for each of the independent variables in the log-linear model is the elasticity. Thus the coefficient for real personal income per capita equals the income elasticity of electricity, and so on. The model equation follows:

$$\ln(\text{IPL Basic per Customer}) = -2.69 + (0.380*\ln(\text{PIPC})) - (0.155*\ln(\text{PERSA})) + (1.29*\ln(\text{THICDDI})) - (0.074*\ln(\text{UE})) + e$$

where e is an error term.
The model parameters are as follows:

Table 1.3.1
Summer Peak Parameters

Variable	Coefficient	T-Ratio	Prob>|T|
Constant	-2.69	-3.15	0%
LPIPC	0.381	4.71	0%
LPERSA	-0.155	-2.18	4%
LTHICDDI	1.29	5.65	0%
UE	-0.074	-2.02	5%
$R^2 = 0.697$ Adj. $R^2 = 0.649$			

The forecast for the temperature-humidity index assumes normal peak-day weather conditions.

1.4. Demand Confidence Interval

To demonstrate the accuracy of the forecast, the 95% confidence interval for the long term forecast is listed below.

Table 1.4.1
Long Term Peak 95% Confidence Interval (mWs)

Year	Low	Base	High
2013	2,550.1	2,775.0	3,021.9
2014	2,563.1	2,794.8	3,050.6
2015	2,609.4	2,848.0	3,109.7
2016	2,639.6	2,884.2	3,153.8
2017	2,668.0	2,918.5	3,194.0
2018	2,695.3	2,951.8	3,235.2
2019	2,717.8	2,980.2	3,269.5
2020	2,744.2	3,013.4	3,309.7
2021	2,767.6	3,041.8	3,345.0
2022	2,791.1	3,070.2	3,379.3
2023	2,815.5	3,101.5	3,418.6
2024	2,842.9	3,136.8	3,463.7
2025	2,868.3	3,170.1	3,504.9
2026	2,892.7	3,200.4	3,543.1
2027	2,915.2	3,229.8	3,580.3

Subpart 2. The **database** for each of the forecasts is listed below.

2.1 Energy
Large Customer data is derived from individual customer’s billing data. Class level data on sales, number of customers and revenues used to determine historical usage, prices, average use per customer and losses are found in “FERC Form No. 1: Annual Report of Major Electric Utilities, Licensees and Others.”

Class level real electricity prices are calculated based on sales and revenue numbers reported to FERC and adjusted for inflation. Iowa GSP and Iowa Real Personal Income estimates come from the Global Insight forecast. Cooling Degree Days are calculated using weather data provided by the Weather Underground.

2.2 Demand Forecast
The number of residential customers is based on the average annual number of residential customers as listed in the FERC form 1. The weather information is based on data provided by the DTN, our third party weather provider.

Subpart 3. A **discussion** of the assumptions made in preparing the forecast.
Historical trends are assumed to continue in future periods. This is assumed for demographics, use per customer for most classes, and losses. Real electric prices are based on projections from the annual energy Outlook produced by US Energy Information Administration (EIA). Forecasts including weather terms are assumed to have normal weather.

Subpart 4. **Subject of Assumption.** In the econometric forecast, no explicit assumptions are made with respect to current or anticipated saturation levels of major electrical appliances and electric space heating. Underlying saturation trends are captured implicitly in the econometric equation. The relatively large nature of changes to the use and demand of the largest customers explains why they are forecasted separately and not simply assumed to grow at historical rates.

Subpart 5. **Coordination of forecasts with other systems.**

A. IPL coordinates its forecasts with its sister company, Alliant Energy-Wisconsin Power & Light (WP&L). In addition, IPL has an agreement with Central Iowa Power Cooperative (CIPCO), which provides for integrated dispatching and reserve calculations, which necessitates coordination of load forecasts.

B. IPL, WP&L, and CIPCO staffs prepared the respective forecasts. IPL exchanges information with CIPCO, but each party is responsible for its own forecast.

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7810.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	M.L Kapp
STREET ADDRESS	2001 Beaver Channel Parkway
CITY	Clinton
STATE	Iowa
ZIP CODE	52732
COUNTY	Clinton
CONTACT PERSON	Kent Ragsdale
TELEPHONE	319-786-7765
PLANT ID	52012
NUMBER OF UNITS	1

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
2	USE	ST	1967	COAL, GAS	531353	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
2	204.4	205.3	51.52	73.16	5.1	

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
2	SUB	350,588	TONS	8,471	NG	34,863	MCF	1,000

ALLOWABLE CODES

Cell Heading	Code	Code Definition
* Unit Status	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
*** Energy Source & Fuel Type	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
** Unit Type	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
**** Unit of Measure	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7810.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME: Dubuque
STREET ADDRESS: 920 Kerper Blvd
CITY: Dubuque
STATE: Iowa
ZIP CODE: 52004
COUNTY: Dubuque
CONTACT PERSON: Kent Ragsdale
TELEPHONE: 319-786-7765

PLANT ID: 52003

NUMBER OF UNITS: 2

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
3	USE	ST	1952	GAS	40497	
4	USE	ST	1959	GAS	41634	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
3	30.9	31.9	18.07	93.76	17.11	
4	35.9	36.6	27.13	93.24	26.14	

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
3	NG	563,059	MCF	1,023	FO2	0	BBL	140,000
4	NG	685,009	MCF	1,023	FO2	0	BBL	140,000

ALLOWABLE CODES

Cell Heading	Code	Code Definition
* Unit Status	USE	In-use
	STB	Stand-by
	RET	Retired
	FUT	Future
	OTHER	Other - provide description
*** Energy Source & Fuel Type	BIT	Bituminous Coal
	COAL	Coal (general)
	DIESEL	Diesel
	FO2	Fuel Oil #2 (Mid Distillate)
	FO6	Fuel Oil #6 (Residual Fuel Oil)
	LIG	Lignite
	LPG	Liquefied Propane Gas
	NG	Natural Gas
	NUC	Nuclear
	REF	Refuse, Bagasse, Peat, Non-wood waste
	STM	Steam
	SUB	Sub-Bituminous Coal
	HYD	Hydro (Water)
	WIND	Wind
	WOOD	Wood
	SOLAR	Solar
	OTHER	Other - provide description

Cell Heading	Code	Code Definition
** Unit Type	CS	Combined Cycle
	IC	Internal Combustion (Diesel)
	GT	Combustion (Gas) Turbine
	HC	Hydro
	ST	Steam Turbine (Boiler)
	NC	Nuclear
	WI	Wind
	OTHER	Other - provide description
**** Unit of Measure	GAL	Gallons
	MCF	Thousand cubic feet
	MMCF	Million cubic feet
	TONS	Tons
	BBL	Barrels
	THERMS	Therms

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7810.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Fox Lake
STREET ADDRESS	County Road 28
CITY	Sherburn
STATE	Minnesota
ZIP CODE	56171
COUNTY	Martin
CONTACT PERSON	Kent Ragsdale
TELEPHONE	319-786-7765
PLANT ID	52006
NUMBER OF UNITS	2

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1950	GAS, OIL	1524	
3	USE	ST	1962	GAS, OIL, COAL	19753	
				PLANT TOTAL	21277	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	12.7	13	1.75	18.68	79.24	
3	76.6	79.1	4.42	61.67	14.68	
PLANT TOTAL	89.3	92.1				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	NG	26,915	MCF	1,029	FO6	0	BBL	0
3	NG	249,775	MCF	1,029	FO6	0	BBL	0

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME: Lansing
STREET ADDRESS: 2320 Power Plant Drive
CITY: Lansing
STATE: Iowa
ZIP CODE: 52151
COUNTY: Allamakee
CONTACT PERSON: Kent Ragsdale
TELEPHONE: 319-786-7765

PLANT ID: 52009
NUMBER OF UNITS: 2

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
3	USE	ST	1957	COAL	-478	
4	USE	ST	1977	COAL	1137284	
				PLANT TOTAL	1136806	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
3	29.4	29.5	0	0	0	
4	247.5	249.6	64.96	88.5	2.09	
PLANT TOTAL	276.9	279.1				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
3	SUB	0	TONS	8,783	FO2	97	BBL	140,000
4	SUB	760,752	TONS	8,783	FO2	9,003	BBL	140,000

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)
$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage)
$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME: Neal No. 4 (jointly owned)
STREET ADDRESS:
CITY: Salix
STATE: Iowa
ZIP CODE: 51052
COUNTY: Woodbury
CONTACT PERSON: Kent Ragsdale
TELEPHONE: 319-786-7765

PLANT ID: 52014
NUMBER OF UNITS: 1

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
4	USE	ST	1979	COAL	1214511	
				PLANT TOTAL	1214511	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
4	165.8	165.8	77.57	93.46	4.84	Shown at Ownership percentage of 25.695%
PLANT TOTAL	165.76	165.76				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
4	SUB	724,255	TONS	8,690	FO2	3,730	BBL	136,566

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Louisa Station No. 1 (jointly owned)	PLANT ID	52010
STREET ADDRESS			
CITY	Fruitland		
STATE	Iowa	NUMBER OF UNITS	1
ZIP CODE	52749		
COUNTY	Louisa		
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-786-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1983	COAL, GAS	224716	
				PLANT TOTAL	224716	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	30.0	30.0	65.80	76.6	2.00	Shown at Ownership percentage of 4%
PLANT TOTAL	30.01	30.01				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	SUB	137,594	TONS	8,485	NG	2,649	MCF	1,015
					FO2	2	BBL	137,058

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Dubuque	PLANT ID	52002
STREET ADDRESS	920 Kerper Blvd		
CITY	Dubuque		
STATE	Iowa	NUMBER OF UNITS	2
ZIP CODE	52004		
COUNTY	Dubuque		
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-786-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	IC	1966	OIL	-41	
2	USE	IC	1966	OIL	-41	
				PLANT TOTAL	-82	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	2.1	2.1	0.17	100	0	
2	1.6	1.6	0.13	2.08	97.92	
PLANT TOTAL	3.7	3.7				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	47	BBL	140,000				
2	FO2	42	BBL	140,000				

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS
Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Hills	PLANT ID	52007
STREET ADDRESS			
CITY	Hills		
STATE	Minnesota	NUMBER OF UNITS	2
ZIP CODE	56138		
COUNTY	Rock		
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-786-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	IC	1996	OIL	-84	
2	USE	IC	1960	OIL	-5	
				PLANT TOTAL	-89	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	2	2	Not Available	Not Available	Not Available	
2	0	0	Not Available	Not Available	Not Available	
PLANT TOTAL	2	2				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	31	BBL	140,000				
2	FO2	0	BBL	140,000				

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)
$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)
$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7810.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Lansing	PLANT ID	52008
STREET ADDRESS	2320 Power Plant Dr		
CITY	Lansing		
STATE	Iowa	NUMBER OF UNITS	2
ZIP CODE	52151		
COUNTY	Allamakee		
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-786-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	IC	1970	OIL	0	
2	USE	IC	1971	OIL	0	
				PLANT TOTAL	0	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	1.2	1.2	0	100	0	
2	1.1	1.1	0	100	0	
PLANT TOTAL	2.3	2.3				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	0	BBL	140,000				
2	FO2	0	BBL	140,000				

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME: Montgomery
STREET ADDRESS:
CITY: Montgomery
STATE: Minnesota
ZIP CODE: 56069
COUNTY: Le Sueur
CONTACT PERSON: Kent Ragsdale
TELEPHONE: 319-786-7765

PLANT ID: 52013
NUMBER OF UNITS: 1

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	GT	1974	OIL	-97	Retired December 2012
				PLANT TOTAL	-97	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0	0	0	0	0	Retired December 2012
PLANT TOTAL	0	0				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	0	BBL	140,000				

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)
$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage)
$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0420 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Fox Lake
STREET ADDRESS	
CITY	Sherburn
STATE	Minnesota
ZIP CODE	56171
COUNTY	Martin
CONTACT PERSON	Kent Ragsdale
TELEPHONE	319-786-7765
PLANT ID	52005
NUMBER OF UNITS	1

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
4	RET	GT	1974	OIL	-31	Retired November 2010
				PLANT TOTAL	-31	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
4	0	0	0	0	0	Retired November 2010
PLANT TOTAL	0	0				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
4	FO2	0	BBL	0				

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7810.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS
Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Lime Creek	PLANT ID	52017
STREET ADDRESS			
CITY	Mason City		
STATE	Iowa	NUMBER OF UNITS	2
ZIP CODE	50401		
COUNTY	Cerro Gordo		
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-786-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	GT	1991	OIL	433	
2	USE	GT	1991	OIL	456	
				PLANT TOTAL	889	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	33.6	39.7	0.19	9.44	88.94	
2	34.7	40.9	0.19	98.19	0	
PLANT TOTAL	68.3	80.6				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	2,232	BBL	140,000				
2	FO2	2,248	BBL	140,000				

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Red Cedar
STREET ADDRESS	
CITY	Cedar Rapids
STATE	Iowa
ZIP CODE	52402
COUNTY	Linn
CONTACT PERSON	Kent Ragsdale
TELEPHONE	319-876-7765
PLANT ID	52021
NUMBER OF UNITS	1

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	GT	1996	NG	-240	
				PLANT TOTAL	-240	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	16.3	20.2	0	0.27	99.73	
PLANT TOTAL	16.3	20.2				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	NG	4,155	MCF	1,017				

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)
$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)
$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7810.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME: Sutherland Station
STREET ADDRESS:
CITY: Marshalltown
STATE: Iowa
ZIP CODE: 50158
COUNTY: Marshall
CONTACT PERSON: Kent Ragsdale
TELEPHONE: 319-876-7765

PLANT ID: 52022
NUMBER OF UNITS: 2

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1955	COAL	53879	
3	USE	ST	1961	COAL	168724	
				PLANT TOTAL	222603	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	28.3	28.4	19.79	74.92	3.45	
3	78.7	79.3	24.9	54.44	16.89	
PLANT TOTAL	107	107.7				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	SUB	28,555	TONS	9,143	NG	258,797	MCF	1,023
3	SUB	56,422	TONS	9,143	NG	751,739	MCF	1,023

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)

$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage)

$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7810.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE:

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS
- Complete one worksheet for each power plant
- Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type and Unit of Measure fields
- Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Marshalltown Gas Turbine	PLANT ID	52023
STREET ADDRESS			
CITY	Marshalltown		
STATE	Iowa	NUMBER OF UNITS	3
ZIP CODE	50158		
COUNTY	Marshall		
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-786-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	GT	1977	OIL	13449	
2	USE	GT	1977	OIL	15994	
3	USE	GT	1977	OIL	625	
				PLANT TOTAL	30068	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	54.4	68.2	2.8	68.46	33.54	
2	48.9	60.7	3.34	99.39	0.56	
3	22.8	34.6	0.15	3.15	96.07	
PLANT TOTAL	126.1	161.5				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	33,162	BBL	138,500				
2	FO2	39,437	BBL	138,500				
3	FO2	1,541	BBL	138,500				

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS
Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Grinnell Gas Turbine	PLANT ID	52024
STREET ADDRESS			
CITY	Grinnell		
STATE	Iowa	NUMBER OF UNITS	2
ZIP CODE			
COUNTY	Poweshiek		
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-786-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	GT	1990	NG	1662	Generation at Units 1 and 2
2	USE	GT	1990	NG	0	is not metered separately
				PLANT TOTAL	1662	

C. UNIT CAPABILITY DATA

CAPACITY (MEGAWATTS)

Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0	25.9	0.47	97.65	2.35	
2	0	20.4	0.33	99.37	0.63	
PLANT TOTAL	0	46.3				

D. UNIT FUEL USED

PRIMARY FUEL USE

Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	NG	43,768	MCF	1,021
2	NG	Included in Unit 1		

SECONDARY FUEL USE

Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS
Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Agency Street Turbine	PLANT ID	52025
STREET ADDRESS			
CITY	Burlington		
STATE	Iowa	NUMBER OF UNITS	4
ZIP CODE			
COUNTY	Des Moines		
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-786-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	RET	GT	1989	NG	-6	Retired November 2010
2	RET	GT	1989	NG	-6	Retired November 2010
3	RET	GT	1989	NG	-6	Retired November 2010
4	RET	GT	1989	NG	-7	Retired November 2010
				PLANT TOTAL	-25	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	0	0	0	0	0	Retired November 2010
2	0	0	0	0	0	Retired November 2010
3	0	0	0	0	0	Retired November 2010
4	0	0	0	0	0	Retired November 2010
PLANT TOTAL	0	0				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ****	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	NG	0	MCF	0	FO2	0	BBL	
2	NG	0	MCF	0	FO2	0	BBL	
3	NG	0	MCF	0	FO2	0	BBL	
4	NG	0	MCF	0	FO2	0	BBL	

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Burlington Gas Turbine	PLANT ID	52026
STREET ADDRESS			
CITY	Burlington		
STATE	Iowa	NUMBER OF UNITS	4
ZIP CODE	52601		
COUNTY	Des Moines		
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-786-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	GT	1995	NG	390	
2	USE	GT	1995	NG	150	
3	USE	GT	1995	NG	400	
4	USE	GT	1995	NG	240	
				PLANT TOTAL	1180	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	14.4	17.1	0.28	84.33	0	
2	13.7	16.4	0.11	5.31	94.62	
3	14.0	16.6	0.3	87.86	12.07	
4	14.8	17.4	0.18	95.92	3.92	
PLANT TOTAL	56.9	67.5				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	NG	9,642	MCF	1,034				
2	NG	3,708	MCF	1,034				
3	NG	9,888	MCF	1,034				
4	NG	5,933	MCF	1,034				

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquified Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Centerville Gas Turbine	PLANT ID	52027
STREET ADDRESS			
CITY	Centerville		
STATE	Iowa	NUMBER OF UNITS	2
ZIP CODE			
COUNTY	Appanoose		
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-786-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	GT	1990	OIL	2393	Generation at Units 1 and 2
2	USE	GT	1990	OIL	0	is not metered separately
				PLANT TOTAL	2393	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	24.4	27.01	0.59	96.5	0.08	
2	25.1	27.6	0.54	96.05	0.52	
PLANT TOTAL	49.5	54.61				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	11,219	BBL	138,500				
2	FO2	Included in Unit 1						

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Ottumwa Generating Station	PLANT ID	52028
STREET ADDRESS			
CITY	Ottumwa		
STATE	Iowa	NUMBER OF UNITS	1
ZIP CODE	52501		
COUNTY	Wappello		
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-786-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1981	COAL	1605821	
				PLANT TOTAL	1605821	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	344.2	346.1	49.16	77.33	9.06	Shown at Ownership percentage of 48.6%
PLANT TOTAL	344.2338	346.1292				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	SUB	1,029,007	TONS	8,396	FO2	9,965	BBL	140,000

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)
$$\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$$

Note: Failure of a unit to be available does not include down time for scheduled maintenance.

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760.

Capacity Factor = (percentage)
$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS
Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A PLANT DATA

PLANT NAME	Burlington Generating Station
STREET ADDRESS	
CITY	Burlington
STATE	Iowa
ZIP CODE	52601
COUNTY	Des Moines
CONTACT PERSON	Kent Ragsdale
TELEPHONE	319-786-7765
PLANT ID	52029
NUMBER OF UNITS	1

B INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1968	COAL	1163795	
				PLANT TOTAL	1163795	

C UNIT CAPABILITY DATA

	CAPACITY (MEGAWATTS)					
Unit ID #	Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	207.7	211.6	69.73	84.33	8.03	
PLANT TOTAL	207.7	211.6				

D UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	SUB	747,465	TONS	8,417	NG	16,290	MCF	1,025

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate.

A. PLANT DATA

PLANT NAME	Centerville Diesel	PLANT ID	52035
STREET ADDRESS			
CITY	Centerville		
STATE	Iowa	NUMBER OF UNITS	3
ZIP CODE			
COUNTY	Appanoose		
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-786-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	IC	1963	OIL	-208	
2	USE	IC	1963	OIL		Generation at Units 1, 2, and
3	USE	IC	1963	OIL		3 is not metered separately
				PLANT TOTAL	-208	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	2.1	2.1	Not Available	Not Available	Not Available	
2	1.8	1.8	Not Available	Not Available	Not Available	
3	1.8	1.8	Not Available	Not Available	Not Available	
PLANT TOTAL	5.7	5.7				

D. UNIT FUEL USED

	PRIMARY FUEL USE				SECONDARY FUEL USE			
Unit ID #	Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	FO2	19	BBL	138,500				
2	FO2	Included in Unit 1						
3	FO2	Included in Unit 1						

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) Hours Unit Failed to be Available X 100 / Hours Unit Called Upon to Produce

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage) Total Annual MWH of Production X 100 / Accredited Capacity Rating (MW) of the Unit X 8,760

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Neal #3	PLANT ID	52030
STREET ADDRESS			
CITY			
STATE		NUMBER OF UNITS	1
ZIP CODE			
COUNTY			
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-786-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1975	COAL	756138	
				PLANT TOTAL	756138	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	146.2	146.2	70.2	92.6	2.6	Shown at Ownership
						percentage of 28%
PLANT TOTAL	146.210	146.210				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	SUB	461,420	TONS	8,635	NG	38,364	MCF	1,018

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS
Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Prarie Creek	PLANT ID	52018
STREET ADDRESS			
CITY	Cedar Rapids		
STATE	Iowa	NUMBER OF UNITS	4
ZIP CODE			
COUNTY	Linn		
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-788-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	ST	1997	COAL	54786	
2	RET	ST	1950	COAL	0	Retired November 2010
3	USE	ST	1958	COAL	39548	
4	USE	ST	1968	COAL	464543	
				PLANT TOTAL	558877	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	2.4	2.4	63.37	100	0	
2	0	0	0	0	0	Retired November 2010
3	35.8	39.2	19.58	76.48	6.53	
4	118.5	122.7	47.22	78.15	9.58	
PLANT TOTAL	156.7	164.3				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	SUB	46,438	TONS	8,574	FO2	0	BBL	0
2	SUB	53,230	TONS	8,574	FO2	0	BBL	0
3	SUB	76,289	TONS	8,574	FO2	0	BBL	0
4	SUB	215,063	TONS	8,574	FO2	0	BBL	0
1					NG	3,164	MCF	1,018
2					NG	3,713	MCF	1,018
3					NG	28,140	MCF	1,018
4					NG	433,627	MCF	1,018
3					Landfill gas	0	MCF	0
4					Landfill gas	0	MCF	0

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage)
$$\frac{\text{Hours Unit Failed to be Available}}{\text{Hours Unit Called Upon to Produce}} \times 100$$

Note Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage)
100 - Maintenance percentage - Forced Outage percentage

Note Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage)
$$\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE (1)

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS: Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Emery	PLANT ID	52036
STREET ADDRESS	11295 230th st		
CITY	Clear Lake		
STATE	Iowa	NUMBER OF UNITS	3
ZIP CODE	50428		
COUNTY	Cerro Gordo		
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-786-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
1	USE	GT	2004	NG	259544	
2	USE	GT	2004	NG	258142	
3	USE	ST	2004	OTHER	350552	Combined Cycle
				PLANT TOTAL	868238	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
1	146.9	159.8	17.38	78.46	1.38	
2	147.8	160.8	17.29	79.97	13.33	
3	240.9	252.3	15.59	82.23	11.07	
PLANT TOTAL	535.6	572.9				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
1	NG	3,125,166	MCF	1,026	FO6	268	BBL	138,500
2	NG	3,107,713	MCF	1,026	FO6	267	BBL	138,500
3								

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peal, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available} \times 100}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production} \times 100}{\text{Accredited Capacity Rating (MW) of the Unit} \times 8{,}760}$

MINNESOTA ELECTRIC UTILITY ANNUAL REPORT (Continued)

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

POWER PLANT AND GENERATING UNIT DATA REPORT: 2012

INSTRUCTIONS
Complete one worksheet for each power plant
Scroll down below the data entry tables to see the ALLOWABLE CODES to be used for Unit Status, Unit Type, Energy Source, Fuel Type, and Unit of Measure fields
Scroll down below the ALLOWABLE CODES to see DEFINITIONS for Capacity Factor, Operating Factor and Forced Outage Rate

A. PLANT DATA

PLANT NAME	Whispering Willow East	PLANT ID	52036
STREET ADDRESS	1584 70th Street		
CITY	Iowa Falls		
STATE	Iowa	NUMBER OF UNITS	121
ZIP CODE	50126		
COUNTY	Franklin		
CONTACT PERSON	Kent Ragsdale		
TELEPHONE	319-786-7765		

B. INDIVIDUAL GENERATING UNIT DATA

Unit ID #	Unit Status *	Unit Type **	Year Installed	Energy Source ***	Net Generation (mwh)	Comments
ALL UNITS	USE	WI	2009	WIND	579025	
				PLANT TOTAL	579025	

C. UNIT CAPABILITY DATA

Unit ID #	CAPACITY (MEGAWATTS) Summer	Winter	Capacity Factor (%)	Operating Factor (%)	Forced Outage Rate (%)	Comments
ALL UNITS	199.7	199.7	33.02	Not Available	Not Available	
PLANT TOTAL	199.7	199.7				

D. UNIT FUEL USED

Unit ID #	PRIMARY FUEL USE Fuel Type ***	Quantity	Unit of Measure ****	BTU Content (for coal only)	SECONDARY FUEL USE Fuel Type	Quantity	Unit of Measure ****	BTU Content (for coal only)
ALL UNITS	WIND							

ALLOWABLE CODES

Cell Heading	Code	Code Definition	Cell Heading	Code	Code Definition
* Unit Status	USE	In-use	** Unit Type	CS	Combined Cycle
	STB	Stand-by		IC	Internal Combustion (Diesel)
	RET	Retired		GT	Combustion (Gas) Turbine
	FUT	Future		HC	Hydro
	OTHER	Other - provide description		ST	Steam Turbine (Boiler)
				NC	Nuclear
*** Energy Source & Fuel Type	BIT	Bituminous Coal		WI	Wind
	COAL	Coal (general)		OTHER	Other - provide description
	DIESEL	Diesel			
	FO2	Fuel Oil #2 (Mid Distillate)	**** Unit of Measure	GAL	Gallons
	FO6	Fuel Oil #6 (Residual Fuel Oil)		MCF	Thousand cubic feet
	LIG	Lignite		MMCF	Million cubic feet
	LPG	Liquefied Propane Gas		TONS	Tons
	NG	Natural Gas		BBL	Barrels
	NUC	Nuclear		THERMS	Therms
	REF	Refuse, Bagasse, Peat, Non-wood waste			
	STM	Steam			
	SUB	Sub-Bituminous Coal			
	HYD	Hydro (Water)			
	WIND	Wind			
	WOOD	Wood			
	SOLAR	Solar			
	OTHER	Other - provide description			

DEFINITIONS

Forced Outage Rate = (percentage) $\frac{\text{Hours Unit Failed to be Available X 100}}{\text{Hours Unit Called Upon to Produce}}$

Note: Failure of a unit to be available does not include down time for scheduled maintenance

Operating Availability = (percentage) 100 - Maintenance percentage - Forced Outage percentage

Note: Maintenance percentage is the number of hours of scheduled maintenance divided by 8,760

Capacity Factor = (percentage) $\frac{\text{Total Annual MWH of Production X 100}}{\text{Accredited Capacity Rating (MW) of the Unit X 8,760}}$

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

INSTRUCTIONS

The individual worksheets in this spreadsheet file correspond closely to the tables in the paper forms received by the utility.
The instructions provided with the paper forms also pertain to the data to be entered in each of the worksheets in this file.
PLEASE DO NOT CHANGE THE NAME OR ORDER OF ANY OF THE WORKSHEET TABS IN THIS FILE

In general, the following scheme is used on each worksheet:
Cells shown with a light green background correspond to headings for columns, rows or individual fields.
Cells shown with a light yellow background require data to be entered by the utility.
Cells shown with a light brown background generally correspond to fields that are calculated from the data entered, or correspond to fields that are informational and not to be modified by the utility.

Each worksheet contains a section labeled Comments below the main data entry area.
You may enter any comments in that section that may be needed to explain or clarify the data being entered on the worksheet.

Please complete the required worksheets and save the completed spreadsheet file to your local computer.
Then attach the completed spreadsheet file to an e-mail message and send it to the following e-mail address:
rule7610.reports@state.mn.us

If you have any questions please contact:

Steve Loomis
MN Department of Commerce
steve.loomis@state.mn.us
(651) 296-8963

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

7610.0120 REGISTRATION

ENTITY ID#	52
REPORT YEAR	2012
RILS ID#	U12001

UTILITY DETAILS	
UTILITY NAME	Interstate Power and Light Company
STREET ADDRESS	200 1st Street SE, PO Box 351
CITY	Cedar Rapids
STATE	IA
ZIP CODE	52401
TELEPHONE	319/786-7609 & 319/786-4136
	Scroll down to see allowable UTILITY TYPES
* UTILITY TYPE	Public

CONTACT INFORMATION	
CONTACT NAME	Kim Ross
CONTACT TITLE	Manager Financial Planning
CONTACT STREET ADDRESS	4902 N. Biltmore Lane
CITY	Madison
STATE	Wisconsin
ZIP CODE	53718-2132
TELEPHONE	608-458-0414
CONTACT E-MAIL	kimberlyross@alliantenergy.com

COMMENTS

PREPARER INFORMATION	
PERSON PREPARING FORMS	Gina Carpenter
PREPARER'S TITLE	Lead Financial Analyst
DATE	7/1/2013

ALLOWABLE UTILITY TYPES

Code

Private
Public
Co-op

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

7610.0310 Item A. SYSTEM FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your entire system for the past year, your estimate for the present year and all future forecast years.

Please remember that the number of customers should reflect the number of customers at year's end, not the number of meters.

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Past Year	2012	No. of Cust.	23,423	419,798	80,892		1,863	842	539	527,357	527,357
		MWH	355,308	3,785,282	4,044,474		7,116,913	56,041	443,433	15,801,451	15,801,451
Present Year	2013	No. of Cust.	23,527	421,664	80,984		1,931	842	539	529,487	529,487
		MWH	348,203	3,709,588	4,031,857		6,985,518	55,762	491,552	15,622,479	15,622,479
1st Forecast Year	2014	No. of Cust.	23,614	423,232	81,521		1,941	842	539	531,690	531,690
		MWH	349,974	3,728,456	4,071,476		7,041,337	55,762	552,224	15,799,228	15,799,228
2nd Forecast Year	2015	No. of Cust.	23,702	424,806	82,062		1,951	842	539	533,903	533,903
		MWH	352,466	3,755,003	4,115,492		7,181,063	55,762	557,163	16,016,947	16,016,947
3rd Forecast Year	2016	No. of Cust.	23,790	426,386	82,606		1,961	842	539	536,125	536,125
		MWH	355,692	3,789,374	4,164,038		7,245,453	55,762	562,155	16,172,473	16,172,473
4th Forecast Year	2017	No. of Cust.	23,879	427,972	83,154		1,971	842	539	538,357	538,357
		MWH	359,016	3,824,788	4,217,160		7,323,209	55,762	562,155	16,342,089	16,342,089
5th Forecast Year	2018	No. of Cust.	23,968	429,563	83,706		1,981	842	539	540,599	540,599
		MWH	361,700	3,853,378	4,271,983		7,387,391	55,762	567,286	16,497,499	16,497,499
6th Forecast Year	2019	No. of Cust.	24,057	431,161	84,261		1,991	842	539	542,851	542,851
		MWH	364,918	3,887,666	4,327,519		7,463,033	55,762	572,466	16,671,364	16,671,364
7th Forecast Year	2020	No. of Cust.	24,146	432,764	84,820		2,002	842	539	545,113	545,113
		MWH	367,832	3,918,706	4,383,776		7,532,508	55,762	577,696	16,836,280	16,836,280
8th Forecast Year	2021	No. of Cust.	24,236	434,374	85,382		2,012	842	539	547,386	547,386
		MWH	370,646	3,948,691	4,440,766		7,600,125	55,762	582,976	16,998,966	16,998,966
9th Forecast Year	2022	No. of Cust.	24,326	435,989	85,949		2,022	842	539	549,668	549,668
		MWH	372,884	3,972,529	4,498,496		7,655,763	55,762	588,307	17,143,740	17,143,740
10th Forecast Year	2023	No. of Cust.	24,417	437,611	86,519		2,033	842	539	551,960	551,960
		MWH	375,558	4,001,016	4,556,976		7,720,827	55,762	593,689	17,303,828	17,303,828
11th Forecast Year	2024	No. of Cust.	24,507	439,238	87,093		2,043	842	539	554,263	554,263
		MWH	378,793	4,035,479	4,616,217		7,798,021	55,762	599,122	17,483,393	17,483,393
12th Forecast Year	2025	No. of Cust.	24,599	440,871	87,670		2,054	842	539	556,576	556,576
		MWH	382,158	4,071,331	4,676,227		7,878,254	55,762	604,608	17,668,340	17,668,340
13th Forecast Year	2026	No. of Cust.	24,690	442,511	88,252		2,064	842	539	558,899	558,899
		MWH	384,957	4,101,154	4,737,018		7,946,695	55,762	610,147	17,835,733	17,835,733
14th Forecast Year	2027	No. of Cust.	24,782	444,157	88,837		2,075	842	539	561,232	561,232
		MWH	388,071	4,134,322	4,798,600		8,022,072	55,762	615,738	18,014,564	18,014,564

* MINING needs to be reported as a separate category only if annual sales are greater than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

7610.0310 Item A. MINNESOTA-ONLY FORECAST OF ANNUAL ELECTRIC CONSUMPTION BY ULTIMATE CONSUMERS

Provide actual data for your Minnesota service area only, for the past year, your best estimate for the present year and all future forecast years.

Please remember that the number of customers should reflect the number of customers at year's end, not the number of meters.

			FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING *	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	MN-ONLY TOTALS	Calculated MN-Only Totals
Past Year	2012	No. of Cust.	1,432	34,121	6,733		260	101	244	42,890	42,890
		MWH	28,581	291,137	160,596		337,508	5,927	16,560	840,309	840,309
Present Year	2013	No. of Cust.	1,648	33,564	6,764		265	99	259	42,599	42,599
		MWH	32,892	286,385	161,353		343,900	5,779	17,609	847,918	847,918
1st Forecast Year	2014	No. of Cust.	1,656	33,732	6,832		267	99	260	42,845	42,845
		MWH	33,056	287,817	162,966		346,307	5,779	17,615	853,541	853,541
2nd Forecast Year	2015	No. of Cust.	1,668	33,968	6,907		269	99	260	43,170	43,170
		MWH	33,288	289,832	164,759		349,078	5,779	17,621	860,356	860,356
3rd Forecast Year	2016	No. of Cust.	1,683	34,273	6,990		271	99	260	43,576	43,576
		MWH	33,587	292,440	166,736		352,219	5,779	17,627	868,389	868,389
4th Forecast Year	2017	No. of Cust.	1,698	34,588	7,077		274	99	260	43,996	43,996
		MWH	33,896	295,128	168,803		356,013	5,779	17,627	877,246	877,246
5th Forecast Year	2018	No. of Cust.	1,711	34,847	7,169		277	99	260	44,362	44,362
		MWH	34,149	297,334	170,998		359,133	5,779	17,635	885,028	885,028
6th Forecast Year	2019	No. of Cust.	1,726	35,157	7,262		280	99	260	44,783	44,783
		MWH	34,453	299,980	173,221		362,811	5,779	17,643	893,886	893,886
7th Forecast Year	2020	No. of Cust.	1,740	35,438	7,356		282	99	260	45,175	45,175
		MWH	34,728	302,375	175,472		366,188	5,779	17,651	902,194	902,194
8th Forecast Year	2021	No. of Cust.	1,753	35,709	7,452		285	99	260	45,557	45,557
		MWH	34,994	304,689	177,754		369,475	5,779	17,659	910,350	910,350
9th Forecast Year	2022	No. of Cust.	1,764	35,924	7,549		287	99	260	45,883	45,883
		MWH	35,205	306,528	180,064		372,180	5,779	17,668	917,425	917,425
10th Forecast Year	2023	No. of Cust.	1,776	36,182	7,647		289	99	260	46,254	46,254
		MWH	35,458	308,726	182,405		375,343	5,779	17,676	925,388	925,388
11th Forecast Year	2024	No. of Cust.	1,792	36,494	7,746		292	99	261	46,683	46,683
		MWH	35,763	311,385	184,777		379,096	5,779	17,684	934,485	934,485
12th Forecast Year	2025	No. of Cust.	1,808	36,818	7,847		295	99	261	47,127	47,127
		MWH	36,081	314,152	187,179		382,996	5,779	17,693	943,880	943,880
13th Forecast Year	2026	No. of Cust.	1,821	37,088	7,949		298	99	261	47,515	47,515
		MWH	36,345	316,453	189,612		386,323	5,779	17,702	952,215	952,215
14th Forecast Year	2027	No. of Cust.	1,836	37,388	8,052		301	99	261	47,936	47,936
		MWH	36,639	319,012	192,077		389,988	5,779	17,710	961,206	961,206

* MINING needs to be reported as a separate category only if annual sales are greatere than 1,000 GWH. Otherwise, include MINING in the INDUSTRIAL category.

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

7610.0310 Item B. FORECAST OF ANNUAL SYSTEM CONSUMPTION AND GENERATION DATA (Express in MWH)

NOTE: (Column 1 + Column 2) = (Column 3 + Column 5) - (Column 4 + Column 6)

It is recognized that there may be circumstances in which the data entered by the utility is more appropriate or accurate than the value in the corresponding automatically-calculated cell.
If the value in the automatically-calculated cell does not match the value that your utility entered, please provide an explanation in the Comments area at the bottom of the worksheet.

[TRADE SECRET DATA BEGINS

		Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	CALCULATED
		CONSUMPTION BY ULTIMATE CONSUMERS IN MINNESOTA in MWH [7610.0310 B(1)]	CONSUMPTION BY ULTIMATE CONSUMERS OUTSIDE OF MINNESOTA in MWH [7610.0310 B(2)]	RECEIVED FROM OTHER UTILITIES in MWH [7610.0310 B(3)]	DELIVERED FOR RESALE in MWH [7610.0310 B(4)]	TOTAL ANNUAL NET GENERATION in MWH [7610.0310 B(5)]	TRANSMISSION LINE SUBSTATION AND DISTRIBUTION LOSSES in MWH [7610.0310 B(6)]	TOTAL WINTER CONSUMPTION in MWH [7610.0310 B(7)]	TOTAL SUMMER CONSUMPTION in MWH [7610.0310 B(7)]	(GENERATION + RECEIVED) MINUS (RESALE + LOSSES) MINUS (CONSUMPTION) SHOULD EQUAL ZERO
Past Year	2012	840,309	14,961,142					7,555,609	8,245,843	0
Present Year	2013	847,918	14,774,561					7,470,031	8,152,448	0
1st Forecast Year	2014	853,541	14,945,686					7,554,545	8,244,682	0
2nd Forecast Year	2015	860,356	15,156,591					7,658,650	8,358,297	0
3rd Forecast Year	2016	868,389	15,304,084					7,733,016	8,439,457	0
4th Forecast Year	2017	877,246	15,464,843					7,814,120	8,527,970	0
5th Forecast Year	2018	885,028	15,612,470					7,888,430	8,609,069	0
6th Forecast Year	2019	893,886	15,777,477					7,971,565	8,699,799	0
7th Forecast Year	2020	902,194	15,934,085					8,050,421	8,785,858	0
8th Forecast Year	2021	910,350	16,088,615					8,128,211	8,870,755	0
9th Forecast Year	2022	917,425	16,226,315					8,197,436	8,946,304	0
10th Forecast Year	2023	925,388	16,378,440					8,273,984	9,029,844	0
11th Forecast Year	2024	934,485	16,548,908					8,359,844	9,123,549	0
12th Forecast Year	2025	943,880	16,724,460					8,448,278	9,220,061	0
13th Forecast Year	2026	952,215	16,883,518					8,528,319	9,307,414	0
14th Forecast Year	2027	961,206	17,053,358					8,613,829	9,400,735	0

TRADE SECRET DATA ENDS]

COMMENTS

Columns 3,4,5,and 6 are Trade Secret

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

7610.0310 Item C. PEAK DEMAND BY ULTIMATE CONSUMERS AT THE TIME OF ANNUAL SYSTEM PEAK (in MW)

	FARM	NON-FARM RESIDENTIAL	COMMERCIAL	MINING	INDUSTRIAL	STREET & HIGHWAY LIGHTING	OTHER	SYSTEM TOTALS	Calculated System Totals
Last Year Peak Day 2012	37.7	1,235.8	531.4		1,237.7	-	87.4	3,130.0	3,130.0

7610.0310 Item D. PEAK DEMAND BY MONTH FOR THE LAST CALENDAR YEAR (in MW)

	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
Last Year 2012	2404	2235	2098	1996	2368	2941	3130	2991	2987	2210	2295	2279

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

7610.0310 Item E. PART 1: FIRM PURCHASES (Express in MW)

These are Full Responsibility Purchases based on the MISO Resource Adequacy process (note nothing is filed with MISO past Planning Year 2013/2014)

NAME OF OTHER UTILITY => [TRADE SECRET DATA BEGINS												
Past Year	2012	Summer									
		Winter									
Present Year	2013	Summer									
		Winter									
1st Forecast Year	2014	Summer									
		Winter									
2nd Forecast Year	2015	Summer									
		Winter									
3rd Forecast Year	2016	Summer									
		Winter									
4th Forecast Year	2017	Summer									
		Winter									
5th Forecast Year	2018	Summer									
		Winter									
6th Forecast Year	2019	Summer									
		Winter									
7th Forecast Year	2020	Summer									
		Winter									
8th Forecast Year	2021	Summer									
		Winter									
9th Forecast Year	2022	Summer									
		Winter									
10th Forecast Year	2023	Summer									
		Winter									
11th Forecast Year	2024	Summer									
		Winter									
12th Forecast Year	2025	Summer									
		Winter									
13th Forecast Year	2026	Summer									
		Winter									
14th Forecast Year	2027	Summer									
		Winter									

TRADE SECRET DATA ENDS]

COMMENTS

Firm Purchases are considered Trade Secret.
Under the MISO RA construct these are called Full Responsibility Purchases.

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

7610.0310 Item E. PART 2: FIRM SALES (Express in MW)

These are Full Responsibility Sales based on the MISO Resource Adequacy process (note nothing is filed with MISO past Planning Year 2013/2014)

NAME OF OTHER UTILITY => [TRADE SECRET DATA BEGINS												
Past Year	2012	Summer										
		Winter										
Present Year	2013	Summer										
		Winter										
1st Forecast Year	2014	Summer										
		Winter										
2nd Forecast Year	2015	Summer										
		Winter										
3rd Forecast Year	2016	Summer										
		Winter										
4th Forecast Year	2017	Summer										
		Winter										
5th Forecast Year	2018	Summer										
		Winter										
6th Forecast Year	2019	Summer										
		Winter										
7th Forecast Year	2020	Summer										
		Winter										
8th Forecast Year	2021	Summer										
		Winter										
9th Forecast Year	2022	Summer										
		Winter										
10th Forecast Year	2023	Summer										
		Winter										
11th Forecast Year	2024	Summer										
		Winter										
12th Forecast Year	2025	Summer										
		Winter										
13th Forecast Year	2026	Summer										
		Winter										
14th Forecast Year	2027	Summer										
		Winter										

TRADE SECRET DATA ENDS]

COMMENTS

Firm Sales are considered Trade Secret.
Under the MISO RA construct these are called Full Responsibility Sales.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

7610.0310 Item F. PART 1: PARTICIPATION PURCHASES (Express in MW)

These are ZRC (Zonal Resource Credit) Purchases based on the MISO Resource Adequacy process (note nothing is filed with MISO past Planning Year 2013/2014)

NAME OF OTHER UTILITY => [TRADE SECRET DATA BEGINS			NextEra	WPL	CIPCo						
Past Year	2012	Summer									
		Winter									
Present Year	2013	Summer									
		Winter									
1st Forecast Year	2014	Summer									
		Winter									
2nd Forecast Year	2015	Summer									
		Winter									
3rd Forecast Year	2016	Summer									
		Winter									
4th Forecast Year	2017	Summer									
		Winter									
5th Forecast Year	2018	Summer									
		Winter									
6th Forecast Year	2019	Summer									
		Winter									
7th Forecast Year	2020	Summer									
		Winter									
8th Forecast Year	2021	Summer									
		Winter									
9th Forecast Year	2022	Summer									
		Winter									
10th Forecast Year	2023	Summer									
		Winter									
11th Forecast Year	2024	Summer									
		Winter									
12th Forecast Year	2025	Summer									
		Winter									
13th Forecast Year	2026	Summer									
		Winter									
14th Forecast Year	2027	Summer									
		Winter									

TRADE SECRET DATA ENDS]

COMMENTS

Participation Purchases are considered Trade Secret.
Under the MISO RA construct these are called ZRC (Zonal Resource Credit) Purchases

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

7610.0310 Item F. PART 2: PARTICIPATION SALES (Express in MW)

These are ZRC (Zonal Resource Credit) Sales based on the MISO Resource Adequacy process (note nothing is filed with MISO past Planning Year 2013/2014)

NAME OF OTHER UTILITY => [TRADE SECRET DATA BEGINS			AECS/EDF	Voluntary Capacity Auction	MISO Auction							
Past Year	2012	Summer										
		Winter										
Present Year	2013	Summer										
		Winter										
1st Forecast Year	2014	Summer										
		Winter										
2nd Forecast Year	2015	Summer										
		Winter										
3rd Forecast Year	2016	Summer										
		Winter										
4th Forecast Year	2017	Summer										
		Winter										
5th Forecast Year	2018	Summer										
		Winter										
6th Forecast Year	2019	Summer										
		Winter										
7th Forecast Year	2020	Summer										
		Winter										
8th Forecast Year	2021	Summer										
		Winter										
9th Forecast Year	2022	Summer										
		Winter										
10th Forecast Year	2023	Summer										
		Winter										
11th Forecast Year	2024	Summer										
		Winter										
12th Forecast Year	2025	Summer										
		Winter										
13th Forecast Year	2026	Summer										
		Winter										
14th Forecast Year	2027	Summer										
		Winter										

TRADE SECRET DATA ENDS]

COMMENTS

Participation Sales are considered Trade Secret.
Under the MISO RA construct these are called ZRC (Zonal Resource Credit) Sales.

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

7610.0310 Item G. LOAD AND GENERATION CAPACITY (Express in MW)

[TRADE SECRET DATA BEGINS

			Column 1	Column 2	Column 3	Column 4	Column 5	Column 6	Column 7	Column 8	Column 9	Column 10	Column 11	Column 12	Column 13	Column 14	Column 15		Column 13
			Net Internal Demand, MISO Coincident 2013+ ~~SEASONAL MAXIMUM DEMAND~~	~~SCHEDULE L. PURCHASE AT THE TIME OF SEASONAL SYSTEM DEMAND~~	Net Internal Demand, MISO coincident 2013+ ~~SEASONAL SYSTEM DEMAND~~	ANNUAL SYSTEM DEMAND (MISO coincident 2013+)	Full Responsibility ~~SEASONAL FIRM~~ PURCHASES (TOTAL)	Full Responsibility ~~SEASONAL FIRM~~ SALES (TOTAL)	~~SEASONAL~~ ADJUSTED NET DEMAND (3 - 5 + 6)	Not Applicable in MISO RA ~~ANNUAL ADJUSTED NET DEMAND (4 - 5 + 6)~~	Asset Based ZRCs ~~NET GENERATING CAPABILITY~~	Zonal Resource Credit ~~PARTICIPATION~~ PURCHASES (TOTAL)	Zonal Resource Credit ~~PARTICIPATION~~ SALES (TOTAL)	ADJUSTED NET CAPABILITY (9 + 10 - 11)	NET RESERVE CAPACITY OBLIGATION	TOTAL FIRM CAPACITY OBLIGATION (7 + 13)	SURPLUS (+) OR DEFICIT (-) CAPACITY (12 - 14)		Required Planning Reserve Margin
Past Year	2012	Summer																	
		Winter																	
Present Year	2013	Summer																	
		Winter																	
1st Forecast Year	2014	Summer																	
		Winter																	
2nd Forecast Year	2015	Summer																	
		Winter																	
3rd Forecast Year	2016	Summer																	
		Winter																	
4th Forecast Year	2017	Summer																	
		Winter																	
5th Forecast Year	2018	Summer																	
		Winter																	
6th Forecast Year	2019	Summer																	
		Winter																	
7th Forecast Year	2020	Summer																	
		Winter																	
8th Forecast Year	2021	Summer																	
		Winter																	
9th Forecast Year	2022	Summer																	
		Winter																	
10th Forecast Year	2023	Summer																	
		Winter																	
11th Forecast Year	2024	Summer																	
		Winter																	
12th Forecast Year	2025	Summer																	
		Winter																	
13th Forecast Year	2026	Summer																	
		Winter																	
14th Forecast Year	2027	Summer																	
		Winter																	

COMMENTS

Load & Gen Cap information is considered Trade Secret. All data is represented based on the MISO Resource Adequacy (RA, aka Module E and Module E-1) process.

TRADE SECRET DATA ENDS]

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0310 Item H. ADDITIONS AND RETIREMENTS (Express in MW)

[TRADE SECRET DATA BEGINS

		ADDITIONS	RETIREMENTS
Past Year	2012		
Present Year	2013		
1st Forecast Year	2014		
2nd Forecast Year	2015		
3rd Forecast Year	2016		
4th Forecast Year	2017		
5th Forecast Year	2018		
6th Forecast Year	2019		
7th Forecast Year	2020		
8th Forecast Year	2021		
9th Forecast Year	2022		
10th Forecast Year	2023		
11th Forecast Year	2024		
12th Forecast Year	2025		
13th Forecast Year	2026		
14th Forecast Year	2027		

COMMENTS
Additions and Retirements are considered Trade Secret
All Additions/Retirements values shown are relative to the prior Summer and are reflected in the "Asset based PRCs" values on Item G

TRADE SECRET DATA ENDS]

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

7610.0430 FUEL REQUIREMENTS AND GENERATION BY FUEL TYPE

Please use the appropriate code for the fuel type as shown in the list at the bottom of the worksheet.

[TRADE SECRET DATA BEGINS

		FUEL TYPE 1		FUEL TYPE 2		FUEL TYPE 3		FUEL TYPE 4		FUEL TYPE 5		FUEL TYPE 6	
		Name of Fuel		Name of Fuel		Name of Fuel		Name of Fuel		Name of Fuel		Name of Fuel	
		Unit of Measure		Unit of Measure		Unit of Measure		Unit of Measure		Unit of Measure		Unit of Measure	
		QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED	QUANTITY OF FUEL USED	NET MWH GENERATED
Past Year	2012												
Present Year	2013												
1st Forecast Year	2014												
2nd Forecast Year	2015												
3rd Forecast Year	2016												
4th Forecast Year	2017												
5th Forecast Year	2018												
6th Forecast Year	2019												
7th Forecast Year	2020												
8th Forecast Year	2021												
9th Forecast Year	2022												
10th Forecast Year	2023												
11th Forecast Year	2024												
12th Forecast Year	2025												
13th Forecast Year	2026												
14th Forecast Year	2027												

LIST OF FUEL TYPES

BIT - Bituminous Coal	LPG - Liquefied Propane Gas	HYD - Hydro (water)
COAL - Coal (general)	NG - Natural Gas	WIND - Wind
DIESEL - Diesel	NUC - Nuclear	WOOD - Wood
FO2 - Fuel Oil #2 (Mid-distillate)	REF - Refuse, Bagasse, Peat, Non-wc	SOLAR - Solar
FO6 - Fuel Oil #6 (Residual fuel oil)	STM - Steam	
LIG - Lignite	SUB - Sub-bituminous coal	

TRADE SECRET DATA ENDS]

COMMENTS

Fuel Requirements are considered Trade Secret.

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

PUBLIC DOCUMENT
TRADE SECRET DATA HAS BEEN EXCISED

7610.0500 TRANSMISSION LINES

Subpart 1. **Existing transmission lines**. Each utility shall report the following information in regard to each transmission line of 200 kilovolts now in existence:

A. a map showing the location of each line;
B. the design voltage of each line;
C. the size and type of conductor;
D. the approximate location of d.c. terminals or a.c. substations; and
E. the approximate length of each line in Minnesota.

Subpart 2. **Transmission line additions**. Each generating and transmission utility, as defined in part 7610.0100, shall report the information required in subpart 1 for all future transmission lines over 200 kilovolts that the utility plans to build within the next 15 years.

Subpart 3. **Transmission line retirements**. Each generating and transmission utility, as defined in part 7610.0100, shall identify all present transmission lines over 200 kilovolts that the utility plans to retire within the next 15 years.

In Use (enter X for selection)	To Be Built (enter X for selection)	To Be Retired (enter X for selection)	DESIGN VOLTAGE	SIZE OF CONDUCTOR	TYPE OF CONDUCTOR	D.C. OR A.C. (specify)	LOCATION OF D.C. TERMINALS OR A.C. SUBSTATIONS	INDICATE YEAR IF "TO BE BUILT" OR "RETIRED"	LENGTH IN MINNESOTA (miles)

COMMENTS

MINNESOTA ELECTRIC UTILITY INFORMATION REPORTING - FORECAST SECTION (Continued)

7610.0600, item A. 24 - HOUR PEAK DAY DEMAND

Each utility shall provide the following information for the last calendar year:

A table of the demand in megawatts by the hour over a 24-hour period for:

1. the 24-hour period during the summer season when the megawatt demand on the system was the greatest; and
2. the 24-hour period during the winter season when the megawatt demand on the system was the greatest

	DATE	DATE	
	7/25/12	1/19/12	<= ENTER DATES
TIME OF DAY	MW USED ON SUMMER PEAK DAY	MW USED ON WINTER PEAK DAY	
0100	2202	1854	
0200	2116	1822	
0300	2030	1812	
0400	1981	1837	
0500	1999	1877	
0600	2085	1987	
0700	2193	2197	
0800	2363	2370	
0900	2541	2375	
1000	2679	2359	
1100	2849	2335	
1200	2959	2346	
1300	3024	2296	
1400	3033	2295	
1500	3096	2260	
1600	3106	2227	
1700	**3130**	2246	
1800	3094	2343	
1900	3058	**2405**	
2000	3046	2355	
2100	2978	2320	
2200	2843	2242	
2300	2579	2137	
2400	2346	2021	

COMMENTS