INTEGRATED RESOURCE PLANNING REPORT

TO THE

INDIANA UTILITY REGULATORY COMMISSION

Submitted Pursuant to
Commission Rule 170 IAC 4-7

November 1, 2013

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EXECUTIVE SUMMARY

Executive Summary

An Integrated Resource Plan (IRP or Plan) explains how a utility company will meet the projected capacity (*i.e.*, peak demand) and energy requirements of its customers. By Indiana rule, Indiana Michigan Power (I&M or Company) is required to provide an IRP that encompasses a 20-year forecast period. I&M's 2013 IRP has been developed using the Company's current assumptions for:

- Customer load requirements – peak demand and energy;
- Commodity prices – coal, natural gas, on-peak and off-peak power prices, capacity and emission prices;
- Supply side alternative costs – including fossil fuel and renewable generation resources; and
- Demand side program costs and analysis.

As shown in its 2013 IRP, I&M has adequate supply and demand resources to meet its load obligations for the next two decades. Due to projected flat and even declining load growth, I&M needs to:

- Ensure that its two Rockport coal units have the necessary environmental controls to comply with United States Environmental Protection Agency (EPA) regulations,
- Maintain operation of the Cook Nuclear plant by completing the Life Cycle Management (LCM) program; and
- Make continued investment in demand-side management.

Additionally, I&M expects that utility-scale solar resources will become economically justifiable by 2020 and that customer-owned solar generation will begin to be economical to customers prior to that, further reducing the requirements for new utility-owned generation.

The Indiana Utility Regulatory Commission (IURC or Commission) issued an order on October 14, 2010, to commence rulemaking to revise/update the current Indiana IRP Rule. This Rule defines the requirements for an IRP by generation owning utilities. The impetus to revise/update the Rule was that the electric utility climate changed since the Rule was promulgated, and updating the Rule would help to provide more relevant IRPs. Although new IRP Rules for Indiana have not been finalized, one rule under consideration involved stakeholder input into the IRP process. Beginning in March 2013, I&M established a stakeholder engagement process to provide an opportunity for interested parties to participate in the IRP process. This IRP was developed with input from "stakeholders," who represented diverse interests and their input has been incorporated in this IRP. Most significantly, eight distinct "stakeholder portfolios" were constructed by the group that satisfied I&M's capacity requirement in lieu of the ultimate economic disposition of both Rockport coal units and the Tanner's Creek 4 retirement or gas conversion decision.

Finally, this IRP recognizes the imminent economic viability of both distributed and utility-scale solar. The stakeholder portfolios encompass a broad spectrum of different resource options that could be used to satisfy I&M's resource requirements, and helped shape the composition of the Preferred Portfolio that I&M presents here.

Environmental Compliance Issues

The 2013 IRP considers final and proposed future EPA regulations that will impact fossil-fueled electric generating units (EGU).

The EPA finalized the Mercury and Air Toxics Standard (MATS) Rule in

December 2011 to replace the court vacated Clean Air Mercury Rule (CAMR). The MATS Rule will regulate emissions of hazardous air pollutants (HAPs) such as mercury, arsenic, chromium, nickel, certain acid gases and organic HAP compounds and was finalized in April 2012 with full implementation in 2015.

In addition, a rule on the handling and disposal of coal combustion residuals (CCR) has been proposed by the EPA, which would require additional capital investment in coal-fired EGUs necessary to convert “wet” ash and bottom ash disposal equipment and systems—including attendant landfills and ponds—to “dry” systems and also build waste-water treatment facilities to process plant water run-off before discharge. Further, the EPA is also developing regulations with respect to the intake of cooling water and discharge of wastewater, as well as effluent limitation guidelines (ELG) for wastewater discharges from steam electric sources, both of which have the potential to require significant capital investment for compliance in the future.

The cumulative cost of complying with these final and proposed environmental rules will be highly burdensome to I&M and its customers. Such requirements will also accelerate environmental equipment retrofits and proposed retirement dates of any currently non-retrofitted coal unit in I&M, depending upon the relative economics.

The analyses used in developing this IRP assume that greenhouse gas (GHG) legislation or regulation on existing units will eventually be implemented. However, rather than a more comprehensive cap-and-trade approach, it is assumed that the resulting impact would be in the form of a carbon dioxide (CO_2) “tax” which would take effect beginning in 2022. The cost of CO_2 is expected to stay within the $15-$20/metric ton range over the long-term analysis period.

Summary of I&M Resource Plans[1]

I&M's total internal energy requirements are forecasted to increase at an average annual rate of 0.2% over the IRP planning period (2014-2033). For the Indiana portion of the Company's service area, the annual growth rate is also expected to be 0.2%. I&M's corresponding summer and winter peak internal demands are forecasted to grow at average annual rates of 0.3% and 0.1%, respectively, with annual peak demand expected to continue to occur in the summer season through 2033.

To determine the appropriate level of such additional demand side, distributed, and renewable resources, I&M utilized the *Plexos®* Linear Program (LP) optimization model to develop a "least-cost" resource plan. Although the IRP planning period is limited to 20 years (through 2033), the *Plexos®* modeling was performed through the year 2040 so as to properly consider various cost-based "end-effects" for the resource alternatives being considered.

As a result of the modeling, and taking into account stakeholder input, I&M developed a Preferred Portfolio. The Preferred Portfolio is intended to provide the lowest reasonable cost of power to I&M's customers while meeting environmental and reliability constraints and reflecting emerging preference for, and the viability of customer self-generation. This portfolio:

- Retires Tanners Creek Plant in 2015.
- Adds environmental controls to Rockport Plant in 2015 to comply with EPA regulations for the MATS Rule.
-

[1] All fgures include both Indiana and Michigan jurisdictions unless noted

- Adds additional environmental controls (*i.e.*, Selective Catalytic Reduction (SCR)) to Rockport Units 1 and 2 in 2017 and 2019, respectively, to reduce nitrogen oxide emissions.
- In 2025 and 2028, adds dry flue gas desulfurization controls (DFGD) to Rockport Units 1 and 2, respectively, to further reduce SO_2 emissions.
- Continues operation of the Cook Nuclear Plant until the mid-2030s.
- Implements Energy Efficiency programs so as to reduce energy requirements by 2,586 GWh (or 9.5% of projected energy needs) by 2033.
- Maintains Indiana demand response programs to reduce peak capacity requirements by 296 MW.
- Adds 200 MW of wind energy from the Headwaters Wind Farm by the end of 2014 and 100 MW of generic wind in 2026.
- Beginning in 2020, I&M will add 50 MW (nameplate) of solar capacity per year.
- Recognizes additional solar capacity will be added by customers, starting in 2016 of about 10 MW (nameplate) and ramping up to about 150 MW (nameplate) by 2033.

Specific I&M capacity and generation changes over the forecast period associated with I&M's Preferred Portfolio are shown in **Figures ES-1a** and **ES-1b,** respectively, and their relative impacts to I&M's capacity and generation position are shown in **Figures ES-2a** and **ES-2b** respectively.

Figure ES-1a
I&M PJM Capacity Changes

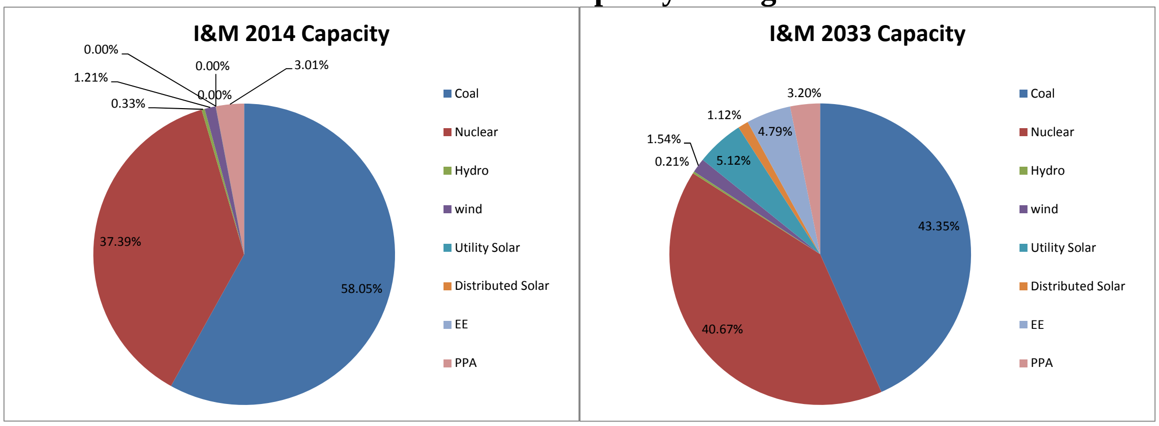
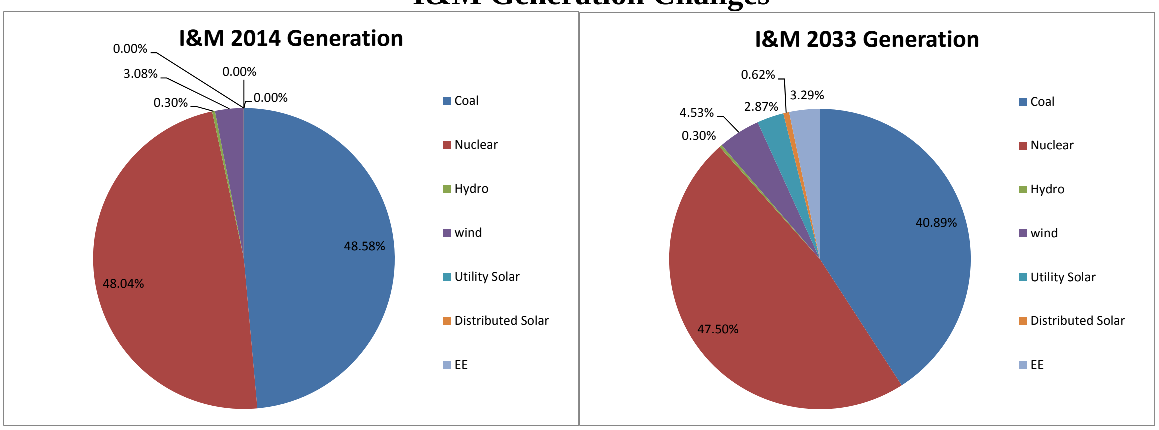


Figure ES-1b
I&M Generation Changes



Figures ES-1a and ES-1b indicate that this Preferred Portfolio would reasonably reduce I&M's reliance on coal-based generation as part of its portfolio of resources, thereby enhancing fuel diversity. Specifically, the Company's capacity mix attributable to coal-fired assets would decline from 58% -to- 43% over the planning period. Similarly, I&M's energy mix attributable to coal-based generation would comparably decrease from 49% -to- 41% over the period. Renewable capacity and generation increases from 2% -to- 13%.

Figure ES-2a
I&M PJM Capacity Position

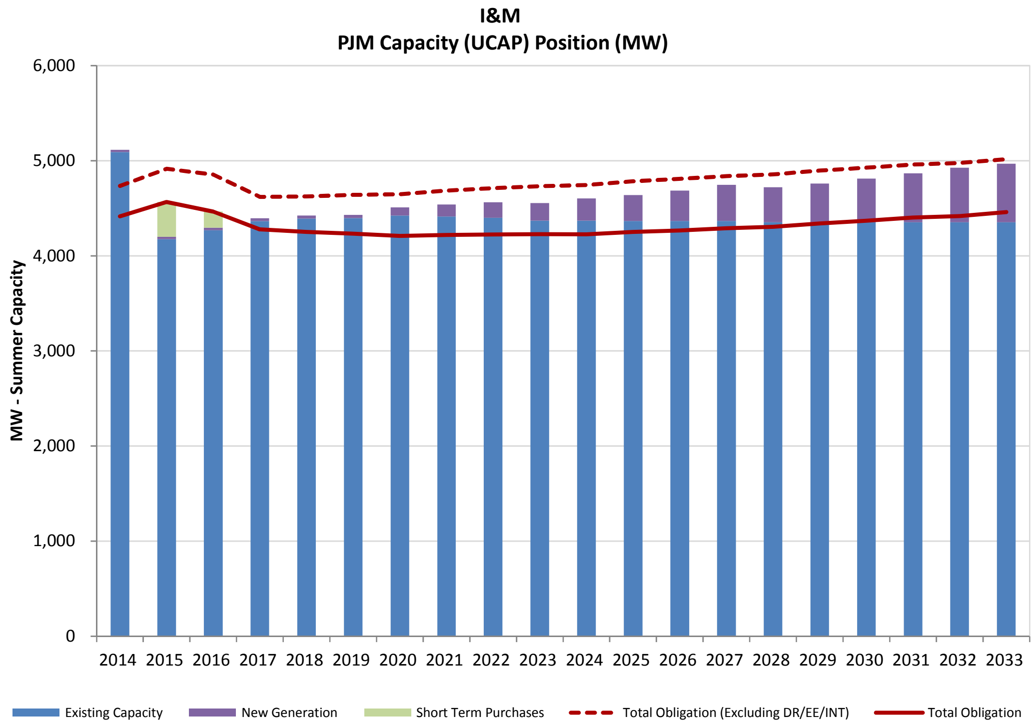
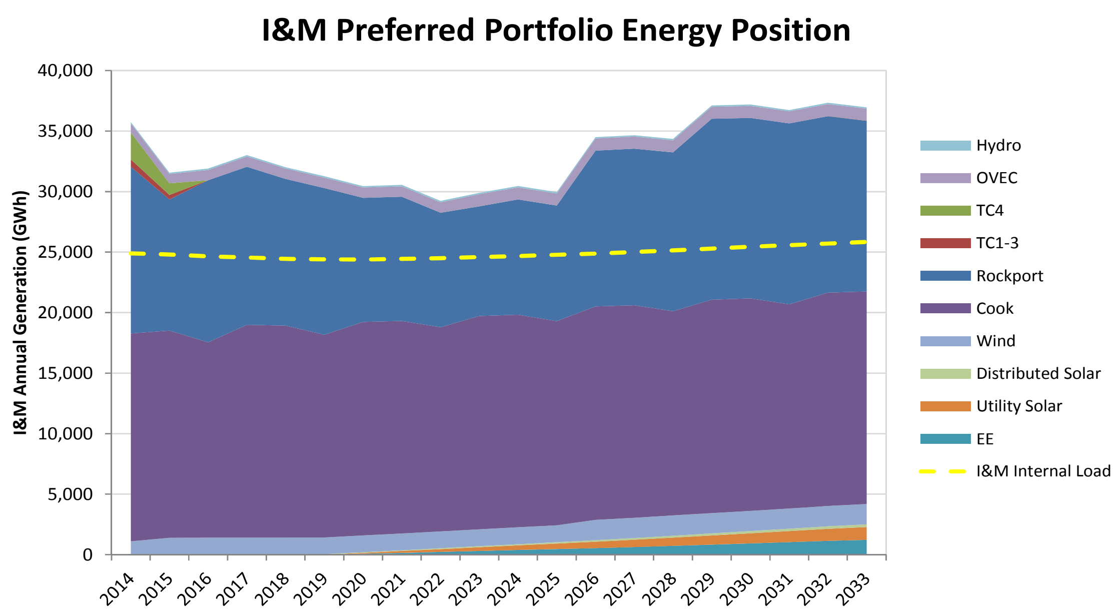
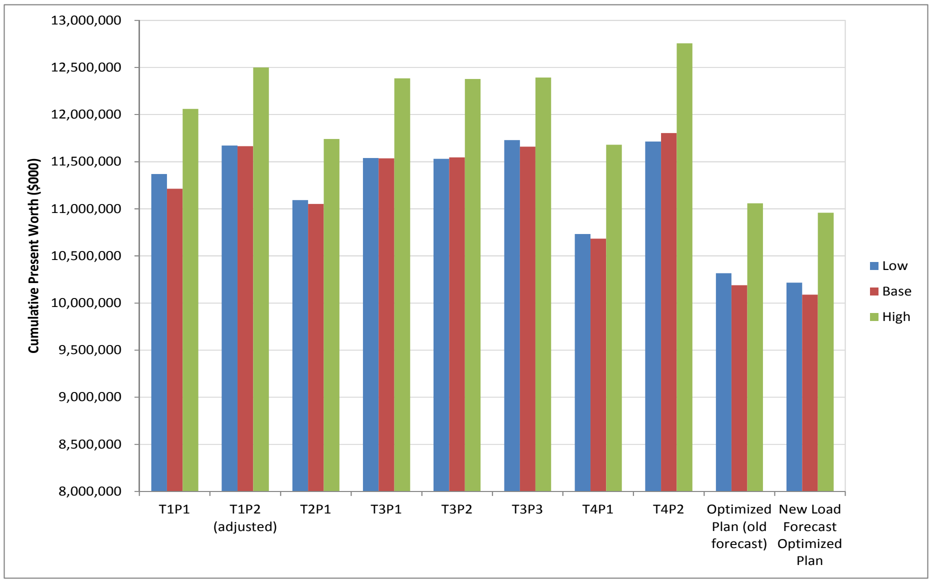


Figure ES-2b
I&M Generation Position



To arrive at the Preferred Portfolio composition, I&M evaluated the eight stakeholder portfolios and two *Plexos*®-derived, "optimum" portfolios (optimized under two distinct load forecasts, "Old" and "New") under three commodity price forecasts (see **Figure ES-3**).

Figure ES-3
CPW of the Analyzed Portfolios



The insight provided by these analyses informed the construction of the Preferred Portfolio which has elements of optimized and stakeholder portfolios.

The following **Table ES-1** provides a summary of the Preferred Portfolio resource optimization modeling under the base case commodity pricing scenario.

Table ES-1

Indiana Michigan Power Company

2013 Integrated Resource Plan

Cumulative Resource Changes (2014-2033)

Preferred Portfolio

IRP Yr.	PJM Plan Year[A]	(Cumulative) RETIREMENTS Coal	(Cumulative) 'PJM' ADDITIONS Coal Rerate	Nuclear Rerate	DSM (EE) Existing[D]	DSM (EE) New	Wind[E]	Solar[F] Utility-Scale	Solar[F] Distributed	Cumul. NET CHANGE	Resulting I&M Reserve Margin	(Cumulative) 'NAMEPLATE' ADDITIONS Wind	Solar Utility-Scale	Solar Distributed
		MW	MW	MW	MW	MW	MW	MW	MW	MW		MW	MW	MW
1	2014[B]	-	-	-	59	-	26	-	-	*85*	*33.0%* [B]	200	-	-
2	2015[B]	(982) [C]	-	-	92	-	26	-	-	*(864)*	*6.7%* [B]	200	-	-
3	2016[B]	(982)	-	-	121	-	26	-	4	*(831)*	*11.5%* [B]	200	-	9
4	2017	(982)	-	50	143	-	26	-	6	*(757)*	*18.6%*	200	-	15
5	2018	(982)	36	50	163	-	26	-	8	*(699)*	*19.9%*	200	-	20
6	2019	(982)	36	50	180	-	26	-	10	*(680)*	*20.6%*	200	-	25
7	2020	(982)	72	50	194	19	26	19	12	*(590)*	*23.3%*	200	50	31
8	2021	(982)	72	50	205	37	26	38	15	*(539)*	*23.8%*	200	100	40
9	2022	(982)	72	50	214	50	26	57	19	*(494)*	*24.3%*	200	150	49
10	2023	(982)	72	50	220	50	26	76	22	*(466)*	*23.9%*	200	200	59
11	2024	(982)	72	50	224	76	26	95	26	*(413)*	*25.3%*	200	250	68
12	2025	(982)	54	50	227	91	26	114	29	*(391)*	*25.5%*	200	300	77
13	2026	(982)	54	50	228	114	39	133	33	*(331)*	*26.2%*	300	350	87
14	2027	(982)	54	50	228	150	39	152	36	*(273)*	*27.1%*	300	400	96
15	2028	(982)	36	50	227	121	39	171	40	*(298)*	*26.0%*	300	450	105
16	2029	(982)	36	50	228	136	39	190	44	*(259)*	*26.0%*	300	500	115
17	2030	(982)	36	50	228	164	39	209	47	*(209)*	*26.5%*	300	550	124
18	2031	(982)	36	50	228	196	39	228	51	*(154)*	*27.0%*	300	600	133
19	2032	(982)	36	50	227	232	39	247	54	*(97)*	*28.1%*	300	650	142
20	2033	(982)	36	50	228	249	39	266	58	*(56)*	*27.9%*	300	700	152
					477 'TOTAL' DSM								*852* 'TOTAL' Solar	

[A] PJM Planning Year is effective 6/1/XXXX.

[B] I&M collectively-participated with affilated AEP-East operating companies in these established PJM (Capacity) Planning Years, electing the Fixed Resource Requirement (FRR) ('self'-)planning option through the 2016 PJM Planning Year. *For purposes of this IRP* only, beginning with the 2017 Planning Year I&M is assumed to be a 'stand-alone' entity.

[C] Tanners Creek Plant (Units 1-4) retirement effective approximately June 1, 2015, concurrent with implementation of U.S. EPA Mercury and Air Toxics Standards (MATS) Rules.

[D] Represents estimated contribution from current/known Indiana and Michigan program activity reflected in the Company's load and demand forecast.

[E] Due to the intermittency of wind resources, PJM initially recognizes 13% of wind resource 'nameplate' MW rating for ICAP determination purposes.

[E] Due to the intermittency of solar resources, PJM initially recognizes 38% of solar resource 'nameplate' MW rating for ICAP determination purposes.

This IRP provides for reliable electric utility service, at reasonable cost, through a combination of maintaining current supply-side resources, renewable supply and demand side programs. I&M will provide for adequate capacity resources to serve its customers' peak demand and required PJM reserve margin needs throughout the forecast period.

Conclusion

The IRP process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the capacity and energy resource plan reported herein reflects, to a large extent, assumptions that are subject to change; it is simply a snapshot of the future at this time. This IRP is not a commitment to a specific course of action, as the future is highly uncertain. The resource planning process is becoming increasingly complex when considering pending regulatory restrictions, technology advancement, changing energy supply pricing fundamentals, uncertainty of demand and energy efficiency advancements. These complexities necessitate the need for flexibility and adaptability in any ongoing planning activity and resource planning processes. Lastly, the ability to invest in extremely capital-intensive generation infrastructure is increasingly challenged in light of current economic conditions and the impact of all these factors on I&M's customers will be a primary consideration in this report.

1) SYNOPSIS

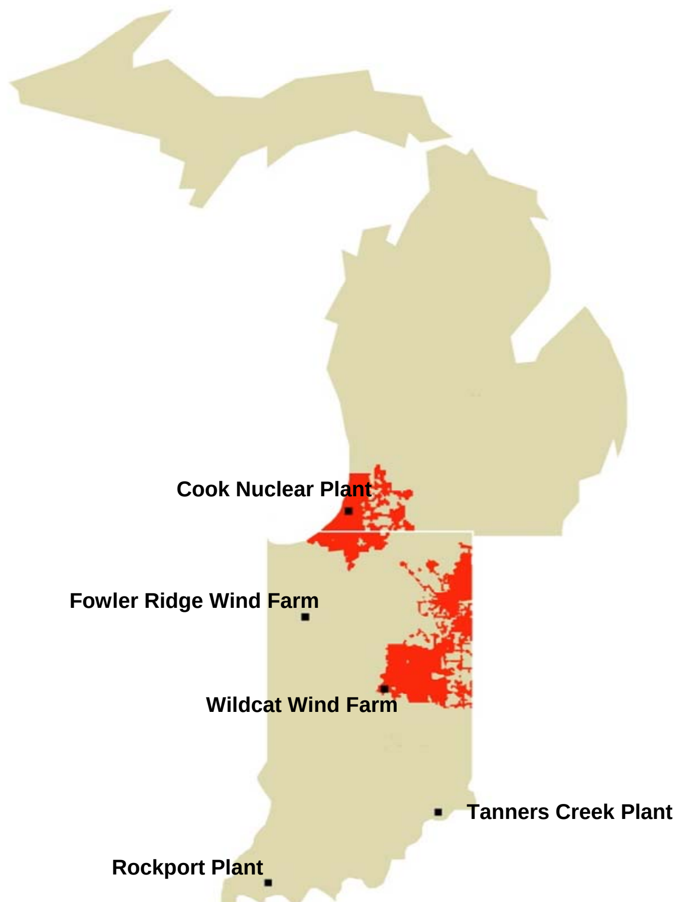
A. Overview

I&M serves 584,000 customers in Indiana and Michigan, including 456,000 in eastern and north central Indiana. The Company has long-term requirements contracts with municipals and cooperatives in Indiana and Michigan. I&M also sells and transmits power at wholesale to other electric utilities, municipalities, electric cooperatives, and non-utility entities engaged in the wholesale power market. The Company is headquartered in Fort Wayne, with external affairs offices in Indianapolis and Lansing, Michigan.

I&M maintains over 5,300 miles of transmission lines, including 615 miles of 765 kV lines – part of the extensive American Electric Power (AEP) network considered by many to be the backbone of the eastern U.S. transmission grid. I&M also operates over 20,000 miles of distribution lines and approximately 6,000 megawatts (MW)[2] of nominal generation. The Company operates two coal-fired generation plants, Rockport and Tanners Creek; the Cook nuclear plant; and six hydroelectric generating stations along the St. Joseph River – two in Indiana and four in Michigan (see **Figure 1A-1)**.

[2] Includes AEP Generating Company's (AEG) 50% share of Rockport Plant (1,310 MW).

Figure 1A-1: I&M Service Territory and Major Generating Facilities



This IRP presents the electrical load forecast for I&M for the period 2014-2033, a resource analysis covering the same period, and the resulting plan for I&M. The plan includes descriptions of assumptions, study parameters, methodologies, and consideration of both supply-side resources and demand-side management (DSM) programs.

As illustrated throughout the chapters of this report, I&M's resources, including its transmission system, are adequate to serve reliably I&M's customers into the future.

B. Process

The planning process comprises several steps, including a forecast of load, consideration of reliability criteria, assessment of current resources, review of existing, and potential supply-side and demand-side resources, and a selection of an optimal plan, including risk assessment. As part of the Public Advisory Process, a stakeholder process was undertaken, where various stakeholders provided inputs to the IRP process. The stakeholders developed a set of resource portfolios that were evaluated in addition to the portfolios developed by the Company. The Stakeholder portfolio development process was carried out by various work groups during the first Stakeholder meeting. The process was designed to draw upon diverse knowledge and various areas of expertise of the stakeholders. In addition to the external stakeholder, many internal working groups have contributed to the I&M resource plan, led by a core multidisciplinary team with a combined total of 159 years of experience in IRP analysis. Additionally, these functional groups received input from several outside consulting organizations (such as IHSCERA, PIRA, Woodmac, Moody's Analytics), bringing an independent view to I&M's plan.

Core Indiana IRP Team

Member	Current Job Title	Area of Expertise	Years of IRP Expertise*
Scott Weaver	Managing Director - Resource Planning and Operational Analysis	Overview-Supply/Demand	10
John Torpey	Director - Integrated Resource Planning	Resource Planning Development	6
Jon MacLean	Manager - Resource Planning	Supply-Demand and Other Factor Integration	37
Mark Becker	Manager - Resource Planning Modeling	Plexos® Optimization Modeling	30
William Castle	Director - Resource & DSM Planning	Demand-Side Management	7
Randy Holliday	Staff Economist	Energy & Demand Forecasting	28
John McManus	VP-Environmental Services	Environment Compliance	22
Kamran Ali	Manager - Regional Transmission Planning	Transmission Planning	6
Brian West	Regulatory Case Manager	IRP Project Coordinator	3
Edward Achaab	Senior Analyst- Integrated Resource Planning	Resource Planning Development	1
Ismael Martinez	Resource Planning Analyst	Plexos® Optimization Modeling	9

*These years are the years of IRP expertise, not necessarily the total years of service by the employee in the utility industry.

The current IRP was scrutinized using a number of sensitivity tests and I&M is confident that the plan will provide substantial guidance regardless of what scenarios may unfold. Several scenarios were analyzed for the purposes of this report. Scenario and sensitivity analysis is described in several areas of the 2013 report. See Chapter 3G, Forecast Uncertainty and Range of Forecasts, as it pertains to Energy and Demand Forecasts; and Chapter 8 for a discussion of commodity pricing scenarios as well as Chapter 8D and Chapter 8E for a discussion on Risk and Sensitivity analysis.

The Company continues to use proprietary data and software models in its IRP process. For example, the Company used *Plexos*® to optimize its plan and alternatives, risk assessment and portfolio risk simulation analysis.

Additionally, in Chapter 3 various models and data sources are utilized such as ARIMA models (see Chapter 3C) and SAE models (also Chapter 3C) as well as Moody's Analytics and Department of Energy (DOE) data.

C. Supply-Side Assessment

In the planning process, several considerations impact I&M's assessment of supply-side resources, namely:

- age of the fossil-fueled generation fleet;
- impact of final and proposed future EPA regulations, state legislated renewable portfolio standards (RPS) and voluntary Clean Energy Goals;
- current mix of capacity which relies heavily on baseload generating assets; and
- availability and cost of alternative assets including utility-scale solar and wind.

These factors provide both objective and subjective data that play into the construction of I&M's ultimate, Preferred Portfolio.

D. Environmental

I&M has developed an IRP that not only allows the Company to meet future resource needs in a reliable and cost effective manner, but also one that considers final and proposed environmental rulemaking and the impacts to existing as well as planned facilities.

Because I&M's installed generation is approximately 38 percent nuclear, I&M and its customers have less risk exposure to environmental challenges that may threaten other utilities. I&M has already implemented a number of pollution control projects to minimize the residual environmental effects of solid and hazardous waste at its facilities and to comply with existing and former air emission regulations, such as with the Title IV acid rain and the nitrogen oxides (NO_x) State Implementation Plan (SIP) Call programs.

Even with reduced risk exposure I&M faces a variety of environmental compliance challenges with the finalized MATS rule and the New Source Review (NSR) Consent Decree. In addition, I&M will face regulations surrounding changes to power plant cooling water intakes, the requirements for handling and storage of coal combustion residuals, ELG and potential regulations related to GHG emissions. Moving into the future, I&M will continue to meet these environmental compliance challenges

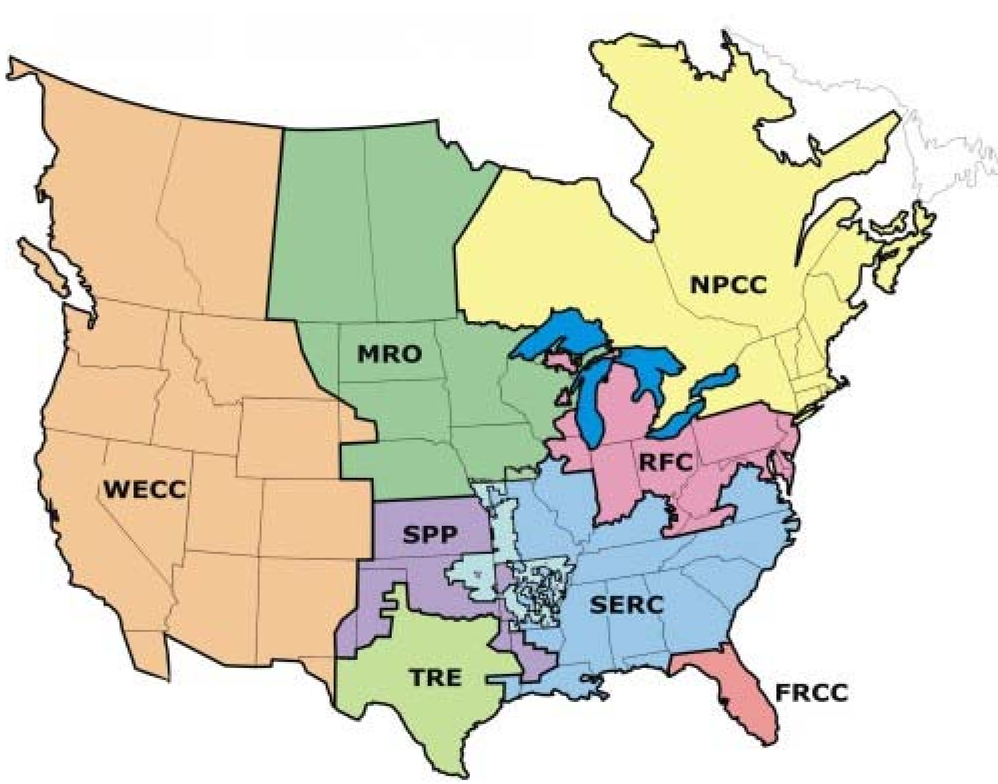
E. Transmission

I&M operates in the Reliability*First* Corporation (RFC) geographic area (see **Figure 1E-1**). RFC is a Regional Entity of the North American Electric Reliability Corporation (NERC).

On October 1, 2004, the AEP System-East Zone became part of the PJM Regional Transmission Organization (RTO) and began participating in the PJM energy market.

I&M transmission, part of the AEP integrated transmission system, together with the transmission systems of other PJM members, is planned on a regional basis via PJM's Regional Transmission Expansion Plan (RTEP) process. AEP's transmission planning activities are carried out as part of and support the RTEP process. Through this planning process, I&M's transmission enhancements are coordinated with the expansion of the transmission system for the entire PJM footprint thereby continuing to ensure a reliable transmission system for meeting I&M's load demand. Also, the Joint Operating Agreement between PJM and the Midwest Independent System Operator (Midwest ISO) provides for joint transmission planning with Midwest ISO, whose membership includes other utilities in Indiana.

Figure 1E-1: NERC Regions



Source: http://www.nerc.com/regional/

F. Demand-Side Management (DSM)[3]

I&M's current and future DSM plans are largely shaped by the Commission's December 9, 2009 Phase II Order in Cause No. 42693 (the "Phase II Order") and Michigan's Energy Optimization Standard (Public Act 295 of 2008). This IRP includes energy efficiency programs designed to comply with those requirements, to the extent practicable. Also, this IRP validates the cost-effectiveness of energy efficiency and other demand-side programs including emerging smart grid technologies.

In addition to consumer energy efficiency programs, I&M continues to offer a variety of customer tariffs with demand response features, namely, a diverse selection of time-of-day rate options and other conservation-related programs including interruptible tariffs that allow customers to achieve savings through more efficient use of electricity or when the system will benefit from reduced peak demand. I&M evaluates its tariffs for potential offering to customers on an ongoing basis.

Further, I&M recognizes the emergence of a potentially significant amount of behind-the-meter distributed generation on its system. This resource, consisting primarily of solar PV panels, but also including small wind and combined heat and power, may be utility or customer owned, with several ownership models possible.

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[3] Demand Side Management (DSM) refers to utility activities designed primarily to influence customer use of electricity that provides a desired change in in a utility's load shape. This includes Demand Response (DR) offerings that reduce peak demand (kW) and Energy Efficiency (EE) programs that encourage energy (kWh) conservation.

G. Major Assumptions

I&M load forecasts account for energy efficiency impacts, such as those included in the Energy Policy Act of 2005 (EPAct 2005), the Energy Independence and Security Act of 2007 (EISA 2007), the Energy Improvement and Extension Act of 2008 (EIEA) and the American Recovery and Reinvestment Act of 2009 (ARRA) as well as the impacts from utility-sponsored efficiency programs.

The load of I&M has been impacted by the economy. While the national recession has technically ended, the economy has remained sluggish. The expectations are that the economy will continue to expand, but at rates slower than have been experienced historically coming out of a recession. The Company continually monitiors the economy at the national and regional levels.   As part of this process, the Company utilizes not only Moody's Analytics, but other public and confidential sources (*e.g.*, the Company has discussions with representatives of its customer's to gauge future electric needs).

I&M, as with any producer of CO_2, will be significantly affected by any GHG regulation. For many years, the potential for requirements to reduce greenhouse gas emissions, including CO_2, has been one of the most significant sustainability issues facing I&M.

The EPA proposed GHG requirements for new power plants in September of this year and it is expected that GHG regulation for existing plants will be proposed until mid-2014, with implementation targeted no sooner than mid-2016. However, the Company also believes that the ultimate implementation will be far later than that date as the EPA will likely contend with litigation regarding this rulemaking.

For this IRP cycle, the impact of a GHG rule on existing units is modeled as a simple carbon dioxide price or tax on emissions. The introduction of a CO_2 tax has secondary impacts on the demand for and costs of commodities. This carbon tax is projected to take effect in 2022.

This IRP reflects achievement of state renewable mandates in Michigan and conformance with voluntary clean energy goals in Indiana.

The resource plan developed for I&M assumes that the Company remains responsible for the generation supply of its retail customers.

H. Cross-Reference Table – proposed rule

Table 1H-1 provides a link between the 170 IAC proposed rule and this Plan. (See **Section G** in the Appendix for the current rule and the link to this Plan)

Throughout the plan, specific sections that respond to specific requirements of the rule are highlighted in the subheadings, with the relevant ruling section identified immediately following the subheading. I&M hopes this system will be helpful in linking key plan elements to the rule.

Table 1H-1

Cross Reference Table

PROPOSED IRP Rule Requirements	Report Reference
170 IAC 4-7-2.1 Public advisory process	
Sec. 2.1 (a) The utility shall have a public advisory process as outlined in this section.	
(b) The utility shall:	
(1) provide information to; and	
(2) solicit and consider relevant input from; any interested party in regard to the development of the utility's IRP and related potential resource acquisition issues.	
(c) The utility shall consider and respond to all relevant input provided by interested parties, including comments and concerns from the commission or its staff.	
(d) The utility retains full responsibility for the content of its IRP.	
(e) The public advisory process shall be administered as follows:	
(1) The utility shall initiate and convene its own public advisory process. The utility will hold at least:	
(A) one introductory meeting; and	
(B) one meeting regarding its preferred resource portfolio; before submittal of its IRP to the commission.	
(2) Depending on the level of interest by commission staff, the public and interested parties in the utility's public advisory process, the utility may hold additional meetings.	
(3) The utility shall take reasonable steps:	
(A) to notify its customers and the commission of its public advisory process; and	
(B) provide notification to known interested parties.	
(4) The timing of meetings shall be determined by the utility:	
(A) to be consistent with its internal IRP development schedule; and	
(B) to provide an opportunity for public participation in a timely manner that may affect the outcome of the utility resource planning efforts.	
(5) The utility or its designee shall:	
(A) chair the participation process;	
(B) schedule meetings; and	
(C) develop agendas for those meetings.	
Participants are allowed to request that relevant items be placed on the agenda of the meetings if they provide adequate notice to the utility.	
(6) Topics discussed in the public advisory process shall include, but are not limited to, the following:	
(A)The utility's load forecast.	
(B) Evaluation of existing resources.	
(C) Evaluation of supply and demand side resource alternatives, including:	
(i) associated costs; and	
(ii) performance attributes.	
(D) Modeling methods.	
(E) Modeling inputs.	
(F) Treatment of risk and uncertainty.	
(G) Rationale for determining the preferred resource portfolio.	Chapter 2F

Cross Reference Table

PROPOSED IRP Rule Requirements	Report Reference
170 IAC 4-7-4 Methodology and documentation requirements	
Sec. 4. (a) The utility shall provide an IRP summary document that communicates core IRP concepts and results to non-technical audiences.	
(1) The summary shall provide a brief description of the utility's existing resources, preferred resource portfolio, short term action plan, key factors influencing the preferred resource portfolio and short term action plan, and any additional details the commission staff may request as part of a contemporary issues meeting. The summary shall describe, in simple terms, the IRP public advisory process, if applicable, and core IRP concepts, including resource types and load characteristics.	Executive Summary, Chapter 2
(2) The utility shall utilize a simplified format that visually portrays the summary of the IRP in a manner that makes it understandable to a non-technical audience.	Executive Summary
(3) The utility shall make this document readily accessible on its website.	
(b) An IRP must include the following:	
(1) A discussion of the:	
(A) inputs;	Chapters 3, 4, 5, 6, 7 and 8
(B) methods; and	Chapters 3, 4, 5, 6, 7 and 8
(C) definitions; used by the utility in the IRP.	Chapters 3, 4, 5, 6, 7 and 8
(2) The data sets, including data sources, used to establish base and alternative forecasts. A third party data source may be referenced. The reference must include the source title, author, publishing address, date, and page number of relevant data. The data sets must include an explanation for adjustments. The data must be provided on electronic media, and may be submitted as a file separate from the IRP , or as specified by the commission.	Chapter 3.K.- Data Sources, Chapter 11 - Appendix A and Confidential Exhibits 4 and 5
(3) A description of the utility's effort to develop and maintain a data base of electricity consumption patterns, by customer class, rate class, NAICS code, and end-use. The data base may be developed using, but not limited to, the following methods:	Chapter 3.M.- Customer Surveys
(A) Load research developed by the individual utility.	Chapter 3.J. - Historical and Projected Load Profiles and Chapter 3.N - Load Research Class Interval Usage Methodolgy
(B) Load research developed in conjunction with another utility.	Not Applicable
(C) Load research developed by another utility and modified to meet the characteristics of that utility.	Not Applicable
(D) Engineering estimates.	Chapter 3.C.3. - Long-term Forecasting Models
(E) Load data developed by a non-utility source.	Chapter 3.C.3. - Long-term Forecasting Models
(4) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.	Chapter 3.M.- Customer Surveys
(5) A discussion of distributed generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting.	Chapter 3.O. - Distributed Generation
(6) A complete discussion of the alternative forecast scenarios developed and analyzed, including a justification of the assumptions and modeling variables used in each scenario.	Chapter 3.G. - Forecast Uncertainty and Range of Forecasts
(7) A discussion of how the utility's fuel inventory and procurement planning practices, have been taken into account and influenced the IRP development.	Chapter 5.C. - Fuel Inventory and Procurement Practices

Cross Reference Table

PROPOSED IRP Rule Requirements	**Report Reference**
(8) A discussion of how the utility's emission allowance inventory and procurement practices for any air emission regulated through an emission allowance system have been taken into account and influenced the IRP development.	Chapter 6 - Environmental Compliance
(9) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	Chapter 2.D. - Reliability Criteria
(10) A brief description and discussion within the body of the IRP focusing on the utility's Indiana jurisdictional facilities with regard to the following components of FERC Form 715:	Chapter 7.B. and FERC 715 (Conf. Exhibit 3)
(A) Most current power flow data models, studies, and sensitivity analysis.	Chapter 7.B. and FERC 715 (Conf. Exhibit 3)
(B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The simulation must include the capability of meeting the standards of the North American Electric Reliability Corporation (NERC).	Chapter 7.B. and FERC 715 (Conf. Exhibit 3)
(C) Reliability criteria for transmission planning as well as the assessment practice used. The information and discussion must include the limits set of its transmission use, its assessment practices developed through experience and study, and certain operating restrictions and limitations particular to it.	Chapter 7.B. and FERC 715 (Conf. Exhibit 3)
(D) Various aspects of any joint transmission system, ownership, and operations and maintenance responsibilities as prescribed in the terms of the ownership, operation, maintenance, and license agreement.	Chapter 7.B. and FERC 715 (Conf. Exhibit 3)
(11) An explanation of the contemporary methods utilized by the utility in developing the IRP, including a description of the following:	
(A) Model structure and reasoning for use of particular model or models in the utility's IRP.	Chapter 8
(B) The utility's effort to develop and improve the methodology and inputs for its:	Chapter 8
(i) forecast;	Chapter 8
(ii) cost estimates;	Chapter 8
(iii) treatment of risk and uncertainty; and	Chapter 8
(iv) evaluation of a resource (supply-side or demand-side) alternative's contribution to system wide reliability. The measure of system wide reliability must cover the reliability of the entire system, including:	Chapters 4, 5, 7 and 8
(AA) transmission;and	Chapter 7
(BB) generation.	Chapter 7
(12) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. Avoided cost shall include, but is not limited to, the following:	Chapter 9, also see below.
(A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement.	Chapter 9.A.
(B) The avoided transmission capacity cost.	Chapter 9.B.
(C) The avoided distribution capacity cost.	Chapter 9.C.
(D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.	Chapter 9.D.

Cross Reference Table

PROPOSED IRP Rule Requirements	**Report Reference**
(13) The actual demand for all hours of the most recent historical year available, which shall be submitted electronically and may be a separate file from the IRP. For purposes of comparison, a utility must maintain three (3) years of hourly data.	Chapter 12.B. and C.- Appendix
(14) Publicly owned utilities shall provide a summary of the utility's:	
(A) most recent public advisory process;	Chapter 2.F.
(B) key issues discussed; and	Chapter 2.F.
(C) how they were addressed by the utility.	Chapter 2.F.
170 IAC 4-7-5 Energy and demand forecasts	
Sec. 5. (a) An electric utility subject to this rule shall prepare an analysis of historical and forecasted levels of peak demand and energy usage which includes the following:	Chapter 3, see below and also Chapter 3. Sections C and D
(1) Historical load shapes, including, but not limited to, the following:	Chapter 3.J. - Historical and Projected Load Profiles
(A) Annual load shapes.	Chapter 3.J. - Historical and Projected Load Profiles
(B) Seasonal load shapes.	Chapter 3.J. - Historical and Projected Load Profiles
(C) Monthly load shapes.	Chapter 3.J. - Historical and Projected Load Profiles
(D) Selected weekly and daily load shapes. Daily load shapes shall include, at a minimum, summer and winter peak days and a typical weekday and weekend day.	Chapter 3.J. - Historical and Projected Load Profiles
(2) Historical and projected load shapes shall be disaggregated, to the extent possible, by customer class, interruptible load, and end-use and demand-side management program.	Chapter 3.J. - Historical and Projected Load Profiles
(3) Disaggregation of historical data and forecasts by customer class, interruptible load, and end-use where information permits.	Chapter 3.E.- Base Load Forecast Results
(4) Actual and weather normalized energy and demand levels.	Chapter 3.I. - Weather-Normalization of Load
(5) A discussion of all methods and processes used to normalize for weather.	Chapter 3.I. - Weather-Normalization of Load
(6) A minimum twenty (20) year period for energy and demand forecasts.	Chapter 3.E.- Base Load Forecast Results
(7) An evaluation of the performance of energy and demand forecasts for the previous ten (10) years, including, but not limited to, the following:	Chapter 3.E.- Base Load Forecast Results
(A) Total system.	Chapter 3.E.- Base Load Forecast Results
(B) Customer classes or rate classes, or both.	Chapter 3.E.- Base Load Forecast Results
(C) Firm wholesale power sales.	Chapter 3.E.- Base Load Forecast Results
(8) Justification for the selected forecasting methodology.	Chapter 3.E.- Base Load Forecast Results
(9) For purposes of subdivisions (1) and (2), a utility may use utility specific data or more generic data, such as, but not limited to, the types of data described in section 4(b)(2) of this rule.	Chapter 3.J. - Historical and Projected Load Profiles and Chapter 3.N.- Load Research Interval Usage Estimation Methodology
(b) A utility shall provide at least three (3) alternative forecasts of peak demand and energy usage. At a minimum, the utility shall include high, low, and most probable energy and peak demand forecasts based on alternative assumptions such as:	Chapter 3.G. - Forecast Uncertainty and Range of Forecasts
(1) Rate of change in population.	Chapter 3.C.3.- Long-term Forecasting Models (base case)
(2) Economic activity.	Chapter 3.C. and G.
(3) Fuel prices.	Chapter 3.C. and G.
(4) Changes in technology.	Chapter 3.C.3.- Long-term Forecasting Models (base case)
(5) Behavioral factors affecting customer consumption.	Chapter 3.C.3.- Long-term Forecasting Models (base case)
(6) State and federal energy policies.	Chapter 3.C.3.- Long-term Forecasting Models (base case)
(7) State and federal environmental policies.	Not Applicable

Cross Reference Table PROPOSED IRP Rule Requirements	Report Reference
170 IAC 4-7-6 Resource assessment	
Sec. 6. (a) The utility shall consider continued use of an existing resource as a resource alternative in meeting future electric service requirements. The utility shall provide a description of the utility's existing electric power resources that must include, at a minimum, the following information:	Chapter 5.C. and Exhibit 5-1
(1) The net dependable generating capacity of the system and each generating unit.	Chapter 5.C. and Exhibit 5-1
(2) The expected changes to existing generating capacity, including, but not limited to, the following:	Chapter 5.C.
(A) Retirements.	Chapter 5.C.
(B) Deratings.	Chapter 5.C.
(C) Plant life extensions.	Chapter 5.C.
(D) Repowering.	Chapter 5.C.
(E) Refurbishment.	Chapter 5.C.
(3) A fuel price forecast by generating unit.	Chapter 5.C. and Conf. Exhibit 1
(4) The significant environmental effects, including:	Chapter 6 and Exhibit 11-1
(A) air emissions;	Chapter 6, see also Chapter 6.D. and Appendix Exhibit 11-1
(B) solid waste disposal;	Chapter 6, see also Chapter 6.B. and Appendix Exhibit 11-1
(C) hazardous waste; and	Chapter 6, see also Chapter 6.C. and Appendix Exhibit 11-1
(D) subsequent disposal; and	Chapter 6, see also Chapter 6.C. and Appendix Exhibit 11-1
(E) water consumption and discharge;	Not Available
at each existing fossil fueled generating unit.	
(5) An analysis of the existing utility transmission system that includes the following:	Chapters 7.C., 7.D., 7.E. and 7.F.
(A) An evaluation of the adequacy to support load growth and expected power transfers.	Chapters 7.D., 7.E. and 7.F.
(B) An evaluation of the supply-side resource potential of actions to reduce transmission losses, congestion, and energy costs.	Chapters 7.C., 7.D. and 7.E.
(C) An evaluation of the potential impact of demand-side resources on the transmission network.	Chapters 7.C., 7.D. and 7.E.
(D) An assessment of the transmission component of avoided cost.	Chapters 9.B. and 9.D.
(6) A discussion of demand-side programs, including existing company-sponsored and government-sponsored or mandated energy conservation or load management programs available in the utility's service area and the estimated impact of those programs on the utility's historical and forecasted peak demand and energy.	Chapter 4 - Demand Side Management
The information listed above in subdivision (a)(1) through subdivision (a)(4) and in subdivision (a)(6) shall also be provided for each year of the planning period.	Chapters 5 and 6.
(b) An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers. For a utility-sponsored program identified as a potential demand-side resource, the utility's IRP shall, at a minimum, include the following:	Chapter 4 - Demand Side Management

Cross Reference Table

PROPOSED IRP Rule Requirements	Report Reference
(1) A description of the demand-side program considered.	Chapter 4 - Demand Side Management
(2) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to resources under consideration such as project life and seasonal operation.	Chapter 4 - Demand Side Management (discussion) and Chapter 9.A. - Avoided Costs
(3) The customer class or end-use, or both, affected by the program.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(4) A participant bill reduction projection and participation incentive to be provided in the program.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(5) A projection of the program cost to be borne by the participant.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(6) Estimated energy (kWh) and demand (kW) savings per participant for each program.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(7) The estimated program penetration rate and the basis of the estimate.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(8) The estimated impact of a program on the utility's load, generating capacity, and transmission and distribution requirements.	Chapter 4 - Demand Side Management
(c) A utility shall consider a range of supply-side resources including cogeneration and non-utility generation as an alternative in meeting future electric service requirements. This range shall include commercially available resources or resources the director may request as part of a contemporary issues technical conference. The utility's IRP shall include, at a minimum, the following:	Chapter 5.D.
(1) Identify and describe the resource considered, including the following:	Chapter 5.D.
(A) Size (MW).	Chapter 5.D.
(B) Utilized technology and fuel type.	Chapter 5.D.
(C) Additional transmission facilities necessitated by the resource.	Chapter 5.D.
(2) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	Chapter 5.B.
(d) A utility shall consider new or upgraded transmission facilities as a resource in meeting future electric service requirements, including new projects, efficiency improvements, and smart grid resources. The IRP shall, at a minimum, include the following:	Chapters 7.B., 7.C., 7.D., 7.E., 7.F., 7.G. and 7.I.
(1) A description of the timing and types of expansion and alternative options considered.	Chapter 7.G. and 7.I.
(2) The approximate cost of expected expansion and alteration of the transmission network.	Chapter 7.G. and 7.I.
(3) A description of how the IRP accounts for the value of new or upgraded transmission facilities for the purposes of increasing needed power transfer capability and increasing the utilization of cost effective resources that are geographically constrained.	Chapters 7.B. and 7.C.
(4) A description of how:	
(A) IRP data and information are used in the planning and implementation processes of the RTO of which the utility is a member; and	Chapters 7.B. , 7.E. and 7.F.
(B) RTO planning and implementation processes are used in and affect the IRP.	Chapters 7.B. , 7.E. and 7.F.

Cross Reference Table

PROPOSED IRP Rule Requirements	Report Reference
170 IAC 4-7-7 Selection of future resources	
Sec. 7. (a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in sections 6(b) through 6(c) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in, but not limited to, a resource summary table. The following information must be provided for a resource selected for further analysis:	Chapter 5.D.
(1) Significant environmental effects, including the following:	Chapter 6
(A) Air emissions.	Chapter 6
(B) Solid waste disposal.	Chapter 6
(C) Hazardous waste and subsequent disposal.	Chapter 6
(D) Water consumption and discharge.	Chapter 6
(2) An analysis of how existing and proposed generation facilities conform to the utility-wide plan to comply with existing and reasonably expected future state and federal environmental regulations, including facility-specific and aggregate compliance options and associated performance and cost impacts.	Chapter 6
(b) Integrated resource planning includes one (1) or more tests used to evaluate the cost-effectiveness of a demand-side resource option. A cost-benefit analysis must be performed using the following tests except as provided under subsection (e):	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(1) Participant.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(2) Ratepayer impact measure (RIM).	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(3) Utility cost (UC).	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(4) Total resource cost (TRC).	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(5) Other reasonable tests accepted by the commission.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(c) A utility is not required to express a test result in a specific format. However, a utility must, in all cases, calculate the net present value of the program impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the discount rate used in the test.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(d) A utility is required to:	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(1) specify the components of the benefit and the cost for each of the major tests; and	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(2) identify the equation used to express the result.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(e) If a reasonable cost-effectiveness analysis for a demand-side management program cannot be performed using the tests in subsection (b), where it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(f) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.	Chapter 4 - Demand Side Management

Cross Reference Table

PROPOSED IRP Rule Requirements	Report Reference
170 IAC 4-7-8 Resource integration	
Sec. 8. (a) The utility shall develop candidate resource portfolios from the selection of future resources in section 7 and provide a description of its process for developing its candidate resource portfolios.	Chapter 8; also see below.
(b) From its candidate resource portfolios, a utility shall select a preferred resource portfolio and provide, at a minimum, the following information:	Chapter 8.C. and 8.D.
(1) Describe the utility's preferred resource portfolio.	Chapter 8.E. and 8.F.
(2) Identify the variables, standards of reliability, and other assumptions expected to have the greatest effect on the preferred resource portfolio.	Chapter 8.B. and 8.C.
(3) Demonstrate that supply-side and demand-side resource alternatives have been evaluated on a consistent and comparable basis.	Chapter 5 and 8
(4) Demonstrate that the preferred resource portfolio utilizes, to the extent practical, all economical load management, demand side management, technology relying on renewable resources, cogeneration, distributed generation, energy storage, transmission, and energy efficiency improvements as sources of new supply.	Chapter 5 and 8
(5) Discuss the utility's evaluation of targeted DSM programs including their impacts, if any, on the utility's transmission and distribution system for the first ten (10) years of the planning period.	Chapter 4.F.
(6) Discuss the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio. The discussion of the preferred resource portfolio shall include, where appropriate, the following:	Chapter 8.F. - Financial Effects
(A) Operating and capital costs.	Chapter 8.F. - Financial Effects
(B) The average cost per kilowatt-hour, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule.	Chapter 8.F. - Financial Effects and Figure 8F-1
(C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio.	Chapter 9.A.; Exhibit 9-1
(D) The utility's ability to finance the preferred resource portfolio.	Chapter 8.F. - Financial Effects
(7) Demonstrate how the preferred resource portfolio balances cost minimization with cost-effective risk and uncertainty reduction, including the following.	
(A) Identification and explanation of assumptions.	Chapter 6 and also throughout the plan as applicable.
(B) Quantification, where possible, of assumed risks and uncertainties, which may include, but are not limited to:	See below.
(i) regulatory compliance;	Chapters 4, 5, 6, 7 and 8
(ii) public policy;	Chapter 6
(iii) fuel prices;	Chapter 8
(iv) construction costs;	Chapter 5
(v) resource performance;	Chapter 8
(vi) load requirements;	Chapter 3
(vii) wholesale electricity and transmission prices;	Chapter 8
(viii) RTO requirements; and	Chapter 5
(ix) technological progress.	Chapter 5

Cross Reference Table PROPOSED IRP Rule Requirements	Report Reference
(C) An analysis of how candidate resource portfolios performed across a wide range of potential futures.	Chapter 8
(D) The results of testing and rank ordering the candidate resource portfolios by the present value of revenue requirement and risk metric(s). The present value of revenue requirement shall be stated in total dollars and in dollars per kilowatt-hour delivered, with the discount rate specified.	Chapter 8
(E) An assessment of how robustness factored into the selection of the preferred resource portfolio.	Chapter 8
(8) Demonstrate, to the extent practicable and reasonable, that the preferred resource portfolio incorporates a workable strategy for reacting to unexpected changes. A workable strategy is one that allows the utility to adapt to unexpected circumstances quickly and appropriately. Unexpected changes include, but are not limited to, the following:	See below.
(A) The demand for electric service.	Chapter 8.C.
(B) The cost of a new supply-side or demand-side technology.	Chapter 8.C.
(C) Regulatory compliance requirements and costs.	Chapter 8.C.
(D) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	Chapter 8.C.
170 IAC 4-7-9 Short term action plan	
Sec. 9. A short term action plan shall be prepared as part of the utility's IRP, and shall cover each of the three (3) years beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the preferred resource portfolio and its workable strategy, as described in 170 IAC 4-7-8(b)(8), where the utility must take action or incur expenses during the three (3) year period. The short term action plan must include, but is not limited to, the following:	Chapter 10 - Short-Term Action Plan
(1) A description of each resource in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following:	Chapter 10 - Short-Term Action Plan
(A) The objective of the preferred resource portfolio.	Chapter 10 - Short-Term Action Plan
(B) The criteria for measuring progress toward the objective.	Chapter 10 - Short-Term Action Plan
(2) The implementation schedule for the preferred resource portfolio.	Chapter 10 - Short-Term Action Plan
(3) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.	Chapter 10 - Short-Term Action Plan
(4) A description and explanation of differences between what was stated in the utility’s last filed short term action plan and what actually transpired.	Chapter 10 - Short-Term Action Plan

2) Objectives and Process

A. Introduction

The AEP East utilities that own generation[4] have for decades operated as part of the AEP integrated public utility holding company system under the now-repealed Public Utility Holding Company Act of 1935. As part of that arrangement, those companies coordinated the planning and operations of their respective generating resources pursuant to the AEP Interconnection Agreement (Pool or Pool Agreement).[5]

On December 17, 2010, in accordance with Section 13.2 of the Pool Agreement, each of the Pool members provided notice to the other members (and to American Electric Power Service Corporation (AEPSC), as agent) to terminate the Pool Agreement (which includes the Interim Allowance Agreement (IAA)), on January 1, 2014. As a result, effective January 1, 2014, I&M will be responsible for its own generation resources and will need to maintain an adequate level of power supply resources to individually meet its own load requirements for capacity and energy, including any required reserve margin.[6]

[4] Appalachian Power Company (APCo), I&M, Kentucky Power Company (KPCo) and Ohio Power Company (OPCo).

[5] The Pool Agreement, which has been amended several times, is on file with the Federal Energy Regulatory Commission (FERC) as I&M's Rate Schedule No. 17)

[6] Three of the current Pool Members – APCo, I&M, and KPCo –together with AEPSC, have agreed to participate under a new arrangement ("the Power Coordination Agreement"), which provides the opportunity for the members to collectively participate in the organized power markets of a regional transmission organization and provides an off-system sales allocation methodology. APCo, I&M, and KPCo together with OPCo and AEP Generation Resources have agreed to enter into an interim arrangement ("the Bridge Agreement") to provide for the allocation of the cost of meeting pre-existing PJM Fixed Resource Requirement (FRR) obligations and settling existing marketing and trading positions that will survive termination of the Pool Agreement. Additional information regarding the Power Coordination Agreement and the Bridge Agreement as they pertain to I&M can be found in FERC Docket No. ER13-235.

This IRP document presents a plan for I&M to meet its obligations as a stand-alone company.

The IRP process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the capacity and energy resource plan reported herein reflects, to a large extent, assumptions that are subject to change; it is simply a snapshot of the future at this time. This IRP is not a commitment to a specific course of action, as the future is uncertain. In light of current economic conditions and movement towards the increased use of renewable generation and end-use efficiency, as well as known and proposed environmental rulemaking to further control fossil plant emissions which will result in the retirement, (environmental emission control) retrofit, or fuel conversion of existing coal-fueled generating units, supply of capacity and energy to I&M will continue to be impacted. The resource planning process is becoming increasingly complex given such pending legislative and regulatory restrictions, technology advancement, changing energy supply pricing fundamentals, uncertainty of demand and energy efficiency advancements, all of which necessitate flexibility in any ongoing planning activity and processes. Lastly, the ability to invest in extremely capital-intensive generation infrastructure is increasingly challenged in light of current economic conditions and the impact of all these factors on I&M customers will be a primary consideration in this report.

Under the **P**referred Portfolio, I&M is anticipated to meet its reserve margin

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These proposed agreements have been submitted to FERC, but have not yet been accepted for filing.

requirements over the forecast period. **Exhibit 8-8** shows the annual capacity additions and resultant reserve margin for this Plan.

B. Objectives

The purpose of this report is to present I&M's IRP process and the resulting plan. The resulting Preferred Plan (The Plan) is intended to provide the lowest reasonable cost of power to I&M's customers while meeting environmental and reliability constraints and reflecting emerging preference for, and the viability of customer self-generation.

C. Assumptions

1. Environmental

This IRP considers final and proposed future EPA regulations, as described in Chapter 6, which will impact fossil-fueled EGUs.

2. Customer Base

While a portion of I&M's service territory is in Michigan, which allows for limited customer switching, this report assumes that I&M customer base remain relatively stable, for the duration of the planning period.

D. Reliability Criteria

(170 IAC 4-7-4(9), & 4(15))

On October 1, 2004, the AEP System-East Zone transferred functional control of its transmission facilities, as well as generation dispatch including the transmission and generation facilities owned by I&M, to PJM (the Commission approved this action by order dated September 10, 2003, in consolidated Cause Nos. 42350 and 42352). With that, the PJM Reliability Assurance Agreement defines the requirements surrounding various reliability criteria, including measuring and ensuring capacity adequacy. In that regard, each Load Serving Entity (LSE) in PJM is required to provide an amount of capacity resources determined by PJM based on several factors, including PJM's Installed Reserve Margin (IRM) requirement. The IRM is based on the amount of resources needed to maintain, among other things, a loss-of-load expectation of one day in ten years. Additionally, load diversity between each LSE and the PJM RTO zones and generating asset equivalent forced outage rates are other factors that impact each LSE's required minimum reserve levels.

The PJM RTO determines generation planning reserve requirements using probabilistic methods and a target loss of load criterion of one day in ten years. The method is similar to that historically used by I&M. PJM determines an installed capacity margin that has to be met by each of its members. This is converted into PJM Unforced Capacity (UCAP) requirements. However, for ease of understanding, the requirement is expressed in this report in terms of Installed Capacity (ICAP).

Although the current plan contains a changing mix of capacity through time, it also contains uncertainty surrounding the long-term forecast. As a result, I&M's IRM was held steady at the current 15.6% threshold for the remainder of the forecast period. However, it is important to note that PJM can revise the IRM annually as required, and as a result I&M will adjust the future IRM estimates accordingly

In February 2007, AEPSC, as agent for the AEP System-East Zone LSEs, gave formal notice of its intent to opt-out of the initial PJM "Reliability Pricing Model" (RPM) capacity auction and, instead, meet its capacity resource obligation through participation in the optional, FERC-authorized Fixed Resource Requirement (FRR) construct. FRR requires I&M to set forth its future capacity resource plan under, essentially, a "self-planning" format. This is an approach that would, however, initially not give I&M access to those generating sources offered into the PJM capacity auction, but rather would allow I&M to be free to plan for and build (or buy) the required generating capacity that would best fit the needs of its customers - such capacity purchases being limited by rule to either non-PJM generation sources, or PJM generation sources not cleared/picked-up within the RPM auction process.

I&M has opted out of the RPM capacity auction through the 2016/17 delivery year, for which the auction was held in May 2013 and will determine for each subsequent year whether to continue to utilize FRR for an additional year or to opt-in to the RPM auction for a minimum five-year period.

E. Planning Process

The resource planning process includes the following basic steps:

1. *Load Forecasting (Energy and Demand)* — Development of energy and peak demand *pro forma* estimates for customers for which I&M has–or anticipates– a known regulatory obligation to serve, as well as an estimation of wholesale customer load and demand profiles intended to optimize available generation.

2. *Reliability Analysis / Reserve Criteria* — Consideration of RTO and/or zonal requirements concerning sufficiency of (long-term) capacity planning reserves.

3. *Review / Assessment of Current Resources* — Broadly construed, this involves consideration of any physical or economic factor – including environmental compliance requirements – that may affect future use of current generation.

4. *Determination of Adequacy of Current Resources / Need for Additional Resources* — Matching existing and currently planned resources against total requirements (load plus reserve requirements), to determine projected shortfalls / needs.

5. *Identification of Capacity Resource Options* — Consideration of various resource options: supply-side and demand-side resources including self-build; market purchase; asset purchases; available technology options; demand response tariffs; energy efficiency programs; etc.

6. *Determination of Optimal Resource Mix and Timing* — Consideration of the timing and optimal resource mix for new supply and demand resources within the planning period under various modeling assumptions.

7. *Implementation Considerations* — Consideration of corporate ability to implement the plan, as well as financial, siting and other practical considerations.

Given the diverse and far-reaching nature of the many elements and participants in this process, it is imperative to emphasize that this is a continuously evolving activity.

In general, assumptions and plans are continually reviewed and modified as new information becomes available, and therefore are subject to change. Such analysis is needed to ensure that changing markets, market structures, technical parameters, are incorporated in any analysis. Reliability and environmental requirements are also constantly re-assessed to balance the interests of all stakeholders, including customers, regulators, and shareholders.

F. Stakeholder Process

1. Background

Pursuant to the IRP Draft Rule, I&M held three public advisory meetings with interested parties (stakeholders) during the development and analysis of the IRP. Invitations to the Stakeholder Process (the process) were sent to all parties who intervened in I&M's latest Indiana base rate case, as well as any known interested parties. The meetings sought to inform stakeholders about I&M's resource planning process, assumptions, and modeling methods as well as to receive input from stakeholders regarding these functions.

Assumptions reviewed with stakeholders included:

1. Load Forecast
2. Cost assumptions for available fossil supply resources including the costs for retrofitting each Rockport unit with an SCR and subsequent DFGD, natural gas combined cycle units, natural gas turbines, and a 200 MW "uprate" of each Cook Nuclear Plant unit.
3. Cost estimates for renewable resources including wind, solar, and other.
4. Cost estimates for demand-side resources including utility-sponsored energy efficiency, demand response, and Electric Energy Control Optimization (EECO).
5. Fundamental pricing assumptions for key economic variables.

Stakeholders were able to construct resource portfolios from the available options that satisfied I&M's load obligation and reserve requirement. In all, eight distinct portfolios were constructed by stakeholders (stakeholder portfolios) that met that criterion. These portfolios were subsequently evaluated using an updated load forecast and pricing assumptions reviewed at the stakeholder meetings.

In addition, I&M constructed two alternate "optimized" portfolios that used the same cost and performance profiles. The first portfolio was optimized using the "old load forecast" and the second portfolio using the "new load forecast". Ultimately, a third, "Preferred Portfolio" which combined the new load forecast-optimized portfolio with some elements of stakeholder portfolios, was formulated by I&M.

The results of the analysis and evaluation of the I&M and stakeholder portfolios was shared with stakeholders at the final public advisory meeting.

2. Stakeholder Portfolios

In an exercise designed to ensure that broad array of a potential resource portfolio were evaluated, stakeholders were engaged to construct portfolios, consisting of resources of their choosing that satisfied the reserve margin criteria by year through 2030. While most elements were in standard sizes (*e.g.,* combined cycle options were 768 MW), stakeholders were afforded the ability to enter "other" elements of any size and operating characteristics. The results of this exercise were eight distinct and plausible "stakeholder portfolios". The portfolios are summarized below (see **Table 2F-1**); additional detail is included in Section E in the Appendix.

Stakeholder portfolios are named according to the subgroup of stakeholders who developed the portfolio, where "T" indicates "table" and "P" indicates "portfolio."

Table 2F-1
Stakeholder Portfolios Summary

	all values in PJM (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	TC4 Gas Conversion	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
	SCR/FGD	-	-	-	-	-	1,105	1,105	1,105	1,105	1,105	1,105	1,105	1,105	1,105	1,105	1,105
	Nuclear Uprate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Stakeholder Portfolio 1 [T1P1]	Solar	-	-	-	140	140	140	140	140	140	140	140	140	140	140	140	140
	Wind	-	-	-	120	120	120	120	120	120	120	120	120	120	120	120	120
	DSM	-	-	-	-	-	27	34	46	58	98	110	122	134	159	161	163
	Combined Cycle	-	-	-	768	768	768	768	768	768	768	768	768	768	768	768	768
	CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Other (User Defined)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Total	500	500	500	1,528	1,528	2,660	2,667	2,679	2,691	2,731	2,743	2,755	2,767	2,792	2,794	2,796

	all values in PJM (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	TC4 Gas Conversion	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
	SCR/FGD	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Nuclear Uprate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Stakeholder Portfolio 2 [T1P2]	Solar	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102	102
	Wind	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65	65
	DSM	22	22	55	60	72	104	136	168	200	232	259	281	303	325	345	365
	Combined Cycle	-	-	-	-	-	768	768	768	768	768	768	768	768	768	768	768
	CT	200	400	600	600	600	800	800	800	800	800	800	800	800	800	800	800
	Other (User Defined)	45	45	45	65	80	160	160	160	160	160	160	160	140	140	140	140
		934	1,134	1,367	1,392	1,419	2,499	2,531	2,563	2,595	2,627	2,654	2,676	2,678	2,700	2,720	2,740

	all values in PJM (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	TC4 Gas Conversion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SCR/FGD	-	-	-	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153
	Nuclear Uprate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Stakeholder Portfolio 3 [T2P1]	Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM	47	54	104	116	156	168	180	212	239	261	283	303	323	343	363	383
	Combined Cycle	-	-	-	-	-	1,536	1,536	1,536	1,536	1,536	1,536	1,536	1,536	1,536	1,536	1,536
	CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Other (User Defined)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		47	54	104	1,269	1,308	2,856	2,868	2,900	2,927	2,949	2,971	2,991	3,011	3,031	3,051	3,071

	all values in PJM (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	TC4 Gas Conversion	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
	SCR/FGD	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Nuclear Uprate	-	-	-	-	-	400	400	400	400	400	400	400	400	400	400	400
Stakeholder Portfolio 4 [T3P1]	Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind	-	-	-	39	39	39	39	39	39	39	39	39	39	39	39	39
	DSM	34	46	80	92	126	158	190	217	239	261	281	301	321	341	361	381
	Combined Cycle	-	-	-	768	768	768	768	768	768	768	768	768	768	768	768	768
	CT	-	-	-	-	-	600	600	600	600	600	600	600	600	600	600	600
	Other (User Defined)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		534	546	580	1,399	1,433	2,465	2,497	2,524	2,546	2,568	2,588	2,608	2,628	2,648	2,668	2,688

	all values in PJM (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	TC4 Gas Conversion	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
	SCR/FGD	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Nuclear Uprate	-	-	-	-	-	400	400	400	400	400	400	400	400	400	400	400
Stakeholder Portfolio 5 [T3P2]	Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind	-	-	-	39	39	39	39	39	39	39	39	39	39	39	39	39
	DSM	22	22	44	44	66	86	106	126	146	166	186	206	226	246	266	286
	Combined Cycle	-	-	-	768	768	1,536	1,536	1,536	1,536	1,536	1,536	1,536	1,536	1,536	1,536	1,536
	CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Other (User Defined)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		522	522	544	1,351	1,373	2,561	2,581	2,601	2,621	2,641	2,661	2,681	2,701	2,721	2,741	2,761

	all values in PJM (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	TC4 Gas Conversion	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	SCR/FGD	-	-	-	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153	1,153
	Nuclear Uprate	-	-	-	-	-	400	400	400	400	400	400	400	400	400	400	400
Stakeholder Portfolio 6 [T3P3]	Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM	-	24	36	48	60	104	126	143	155	167	177	187	197	207	217	227
	Combined Cycle	-	-	-	-	-	768	768	768	768	768	768	768	768	768	768	768
	CT	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
	Other (User Defined)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		200	224	236	1,401	1,413	2,625	2,647	2,664	2,676	2,688	2,698	2,708	2,718	2,728	2,738	2,748

	all values in PJM (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	TC4 Gas Conversion	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
	SCR/FGD	-	-	-	1,153	1,153	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258	2,258
	Nuclear Uprate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Stakeholder Portfolio 7 [T4P1]	Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Combined Cycle	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Other (User Defined)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		500	500	500	1,653	1,653	2,758	2,758	2,758	2,758	2,758	2,758	2,758	2,758	2,758	2,758	2,758

	all values in PJM (MW)	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
	TC4 Gas Conversion	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500	500
	SCR/FGD	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Nuclear Uprate	-	-	-	-	-	400	400	400	400	400	400	400	400	400	400	400
Stakeholder Portfolio 8 [T4P2]	Solar	-	-	-	-	-	-	-	-	-	-	45	97	97	97	97	97
	Wind	-	-	-	-	-	-	-	26	26	26	26	26	26	26	26	26
	DSM	-	-	-	-	-	5	10	20	30	40	50	82	94	129	131	151
	Combined Cycle	-	-	-	768	768	1,536	1,536	1,536	1,536	1,536	1,536	1,536	1,536	1,536	1,536	1,536
	CT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	Other (User Defined)	-	-	-	3	14	-	-	-	-	5	-	-	2	-	31	46
		500	500	500	1,271	1,282	2,441	2,446	2,482	2,492	2,507	2,557	2,641	2,655	2,688	2,721	2,756

3. Issues Addressed During Stakeholder Process

The following is a discussion of the relevant issues raised by stakeholders during the public advisory process. Relevant items raised during the three meetings were either answered during the meeting or addressed at a subsequent meeting.

a. Energy Efficiency

Issues concerning energy efficiency arose during the course of the process. There was discussion on whether or not I&M could meet or exceed the regulated mandates that are in place for Indiana utilities through 2019. Incremental Energy Efficiency was not provided as a predefined resource option for stakeholder portfolios prior to 2020, although it could be included as a user-defined resource. I&M contends that the mandates in place are aggressive and are based on performance from states that use electricity in a materially different way than in Indiana. In addition, a disproportionately high percentage of programs in other states relied on lighting programs that will have limited utility, prospectively, given the impacts of EPAct 2005 and EISA 2007, primarily. Additional discussion of energy efficiency issues can be found in Section 4.

I&M proposed to run "sensitivity" where regulatory mandates are not met, which subsequently has become I&M's view of a "base" or expected outcome.

b. Distributed Generation

With low natural gas prices and rapidly declining installed solar costs, both (distributed) combined heat and power (CHP) and solar resources are increasingly viable resources. Indiana requires that host utilities credit full retail net metering for power sold back to the grid. For applications that meet the Public Utility Regulatory Policy Act

(PURPA) criteria, the utility pays its avoided costs. There was discussion on whether it made sense for I&M to offer compensation above these respective amounts in order to encourage or expedite the adoption of these efficient technologies. Further, the ability for “third-party” financing of these assets, which is not currently allowed by regulation, was suggested.

The issue of third-party financing was deemed to be out of scope for the resource planning effort. The need to pay amounts incremental to what is currently prescribed by regulation hinges on differences between the value of those resources to I&M within PJM and the retail net metering rate or PURPA rate which is being paid (see Chapter 4 for a detailed analysis). In order for I&M to justify, economically, paying more than prescribed, the assets must offer incremental value that is not covered in the rate alone. Often, in the case of distributed generation, this value could come in the form of avoided transmission and distribution costs. However, given I&M’s flat to declining load growth, there is only limited, case-by-case, opportunity to defer transmission and distribution costs.

c. Solar Price Declines

Stakeholder input was influential in refining the modeling assumptions regarding solar costs. Because of the rapidly changing nature of those costs, the Stakeholders were able to add a current and relevant market-driven perspective to fine-tune the solar cost inputs. Additional discussion of solar pricing assumptions can be found in Chapter 5.

G. Planning Organization

The IRP presents results based on input received from many functional areas coordinated by the AEPSC Corporate Planning & Budgeting (CP&B) Department. The areas individually investigated were:

- *Existing Unit Disposition* – examination of the physical and financial attributes and focused evaluations surrounding potential disposition options for certain existing generating units.
- *New Generation / Technology Review* – assessment of generation technologies considered for modeling, including renewables; as well as optimal unit siting and technology options.
- *Capacity, Load / Demand, Reserves* – determination of load and demand profiles (retail and wholesale) to be modeled, existing unit capability modifications needed, as well as zonal (capacity) reliability requirements; and initial "baseline" planning reserve margin profiles.
- *Transmission Integration Review* – review of physical transmission constraints relating to current power and energy import/export capabilities that would impact the IRP, as well as a review of the associated relative transmission infrastructure impacts and costs.
- *Demand-Side Management* – evaluations of potential cost-effective Demand Side Management (DSM) programs.
- *Renewable Resource Evaluation* – evaluations of potential cost-effective Renewable Resource programs that will aid in the achievement of state-mandated or voluntary renewable energy targets.
- *Resource Planning (RP) Modeling* – modeling of the least-cost "type and timing" of capacity resources to meet reliability and environmental compliance requirements at or near the lowest reasonable cost.
- *Finance and Regulatory Planning Modeling* – modeling of the corporate financial impacts of the IRP strategy in conjunction with other anticipated financial requirements.

3) Energy and Demand Forecast

A. Summary of Load Forecast

1. Forecast Assumptions

The I&M load forecast in this report is based on an economic outlook issued in December 2012 by Moody's Analytics. The forecast is based on load experience prior to 2013. Moody's Analytics projects moderate growth in the U.S. economy during the 2014-2033 forecast period, characterized by moderate inflation and a 2.3% average annual rise in real Gross Domestic Product (GDP), with the implicit GDP price deflator expected to rise by 1.9% per year. Industrial output, as measured by the Federal Reserve Board's index of industrial production, is projected to grow at 0.4% per year during the same period. Moody's Analytics also created the regional economic forecasts. The outlook for I&M's Indiana service area projects employment growth of 0.2% per year during 2014-2033, with real regional income per-capita growth projected to be 1.9%.

Inherent in the load forecasts are the impacts of past customer energy conservation activities, including company-sponsored DSM programs already implemented. The load impacts of future or expanded DSM programs are analyzed and projected separately, and appropriate adjustments applied to the load forecasts, as discussed in Chapter 4 of this report.

The load forecast does incorporate end-use concepts in its residential and commercial forecasts, which enables the evaluation of energy efficiency standards and other energy conservation trends.

2. Forecast Highlights

I&M's total internal energy requirements are forecasted to increase at an average annual rate of 0.2% from 2014 to 2033. For the Indiana portion of the Company's service area, the annual growth rate is expected to be 0.2%. I&M's corresponding summer and winter peak internal demands are forecasted to grow at average annual rates of 0.3% and 0.1%, respectively, with annual peak demand expected to continue to occur in the summer season through 2033.

B. Overview of Load Forecasting Methodology

I&M's load forecasts are based mostly on econometric, supplemented with state-of-the-art statistically adjusted end-use, analyses of time-series data – producing an internally consistent forecast. This consistency is enhanced by model logic expressed in mathematical terms and quantifiable forecast assumptions. This is helpful when analyzing future scenarios and developing confidence bands. Additionally, econometric analysis lends itself to objective model verification by using standard statistical criteria. This is particularly helpful because it allows apples-to-apples comparisons of different companies and forecast periods.

In practice, econometric analysis highlights alternatives in forecasting models that may not be immediately obvious to the layperson. Likewise, professional judgment is required to interpret statistical criteria that are not always clear-cut. I&M's analysts strive to interpret this data to produce as useful and as accurate a forecast as possible.

In pursuit of that goal, I&M's energy requirements forecast is derived from two sets of econometric models: 1) a set of monthly short-term models and 2) a set of long-term models, with some using monthly data and others using annual data. This procedure permits easier adaptation of the forecast to the various short- and long-term planning purposes that it serves.

- For the first full year of the forecast, the forecast values are generally governed by the short-term models, using billed or metered energy sales. The long-term sales are determined by the long-term models using billed sales.

- The short- and long-term forecasts are usually blended during the first six months of the second full year of the forecast. The blending ensures a smooth transition from the short-term to the long-term forecast.

The blended sales forecasts are converted to billed and accrued energy sales, which are consistent with the energy generated.

In both sets of models, the major energy classes are analyzed separately. Inputs such as regional and national economic conditions and demographics, energy prices, weather factors, special information such as known plans of specific major customers, and informed judgment are all used in producing the forecasts. The major difference between the two is that the short-term models use mostly trend, seasonal, and weather variables, while the long-term models use structural variables, such as population, income, employment, energy prices, and weather factors, as well as trends. Supporting forecasting models are used to predict some inputs to the long-term energy models. For example, natural gas models are used to predict sectoral natural gas prices that then serve as inputs.

Either directly, through national economic inputs to the forecast models, or indirectly, through inputs from supporting models, I&M's load forecasts are influenced by the outlook for the national economy. For the load forecasts reported herein, Moody's Analytics' December 2012 forecast was used as the basis for that outlook. Moody's

Analytics' regional forecast, which is consistent with its national economic forecast, was used for the regional economic forecast of income, employment, households, output, and population.

Company energy efficiency and demand side management program goals are included in the load forecast. The incremental impacts discussed in section 4, Demand Side Management. The impacts are subtracted from the blended sales forecast by revenue class.

The demand forecast model is a series of algorithms for allocating the monthly net internal energy to hourly demand. The inputs into forecasting hourly demand are internal energy, weather, 24-hour load profiles and calendar information. Flow charts depicting the structure of the models used in projecting electric load requirements are shown in Exhibits 3-1. Displays of model equations, including the results of various statistical tests, along with data sets, are provided in the Appendix and in Exhibits 5 and 6 of the Confidential Supplement. Due to the voluminous nature of the model outputs, only model results for energy sales in the Indiana service area and peak demand for the Company are provided (Section P).

C. Forecasting Methodology for Internal Energy Requirements
(170 IAC 4-7-4(5) and 170 IAC 4-7-5(a))

1. General

This section provides a detailed description of the short-term and long-term models employed in producing the forecasts of Indiana energy consumption, by customer class. For the purposes of the load forecast, the short term is defined as the first one to two years, and the long term as the years beyond the short term.

Conceptually, the difference between short and long term energy consumption relates to changes in the stock of electricity-using equipment, rather than the passage of time. The short term covers the period during which changes are minimal, and the long term covers the period during which changes can be significant. In the short term, electric energy consumption is considered to be a function of an essentially fixed stock of equipment. For residential and commercial customers, the most significant factor influencing the short term is weather. For industrial customers, economic forces that determine inventory levels and factory orders also influence short-term utilization rates. The short-term models recognize these relationships and use weather and recent load growth trends as the primary variables in forecasting monthly energy sales.

Over time, demographic and economic factors such as population, employment, income, and technology determine the nature of the stock of electricity-using equipment, both in size and composition. Long-term forecasting models recognize the importance of these variables and include most of them in the formulation of long-term energy forecasts.

Relative energy prices also have an impact on electricity consumption. One difference between the short-term and long-term forecasting models is energy prices are only included in long-term forecasts. In the short-term, consumers have little opportunity to respond to changes in price. In the long term, however, these constraints are lessened as durable equipment is replaced and as price expectations come to fully reflect price changes.

2. Short-term Forecasting Models

The goal of I&M's short-term forecasting models is to produce an accurate load forecast for the first full year. To that end, the short-term forecasting models generally employ a combination of monthly and seasonal binaries, time trends, and monthly heating and cooling degree-days. The heating and cooling degree-days are measured at weather stations in the service area. The forecasts relied on autoregressive integrated moving average (ARIMA) models.

The estimation period for the short-term models was January 2003 through January 2013.

a. Residential and Commercial Energy Sales

Residential and commercial energy sales are developed using ARIMA models to forecast usage per customer and number of customers. The usage models relate usage to lagged usage, lagged error terms, heating and cooling degree-days and binary variables. The customer models relate customers to lagged customers, lagged error terms and binary variables. The energy sales forecasts are a product of the usage and customer forecasts.

b. Industrial Energy Sales

Short-term industrial energy sales are forecast separately for 10 large industrial customers in Indiana and for the remainder of industrial energy customers as a unit. These 11 short-term industrial energy sales models relate energy sales to lagged energy sales, lagged error terms and binary variables. The industrial models are estimated using ARIMA models. The short-term industrial energy sales forecast is a sum of the forecasts for the 10 large industrial customers and the forecast for the remainder of the industrial customers.

c. All Other Energy Sales

The "all other" energy sales category includes public street and highway lighting, municipals, cooperative (*e.g.*, Wabash Valley Power Association) and the Indiana Municipal Power Association (IMPA). The Indiana municipal customers reflected in the forecast include Auburn, Avilla, Bluffton, Garrett, Mishawaka, New Carlisle and Warren. Auburn is forecasted separately and the remainder of the municipals is forecasted in aggregate.

Both the other retail and municipal models are estimated using ARIMA models. I&M's short-term forecasting model for public street and highway lighting energy sales includes binaries, and lagged energy sales. The sales-for-resale models include binaries, heating and cooling degree- days, lagged error terms and lagged energy sales.

3. Long-term Forecasting Models
(170 IAC 4-7-4(2) (D) and (E), and 170 IAC 4-7-5(b) (1) through (6))

The goal of the long-term forecasting models is to produce a reasonable load outlook. Given that goal, the long-term forecasting models, which were separately estimated for the Indiana and Michigan service areas, employ a full range of structural economic and demographic variables, electricity and natural gas prices, weather as measured by annual heating and cooling degree-days, and binary variables to produce load forecasts conditioned on the outlook for the U.S. economy, for the I&M service-area economy, and for relative energy prices.

Most of the explanatory variables enter the long-term forecasting models in a straightforward, untransformed manner. In the case of energy prices, however, it is assumed, consistent with economic theory, that the consumption of electricity responds to changes in the price of electricity or substitute fuels with a lag, rather than instantaneously. This lag occurs for reasons having to do with the technical feasibility of quickly changing the level of electricity use even after its relative price has changed, or with the widely accepted belief that consumers make their consumption decisions on the basis of expected prices, which may be perceived as functions of both past and current prices.

There are several techniques, including the use of lagged price or a moving average of price, which can be used to introduce the concept of lagged response to price change into an econometric model. Each of these techniques incorporates price information from previous periods to estimate demand in the current period.

The estimation period for the long-term load forecasting models was 1995-2012. The long-term energy sales forecast is developed by blending the first six month of the second full year of the short-term forecast with the long-term forecast. The energy sales forecast is developed by making a billed/unbilled adjustment to derive billed and accrued values, which are consistent with monthly generation.

a. Retail Natural Gas and Electricity Pricing Forecasts

In order to produce forecasts of certain independent variables used in the long-term internal energy requirements forecasting models, a supporting forecast was developed, i.e., a natural gas price forecast for the Company's service area.

The forecast price of natural gas used in I&M's energy models comes from a forecast of state natural gas prices for four primary consuming sectors: residential, commercial, industrial and electric utilities. The forecast of sectoral prices was assumed to have the same growth as the U.S. sectoral prices. The U.S. natural gas price forecasts were obtained from U.S. DOE/EIA's *2013 Annual Energy Outlook*.

The sectorial electricity prices are developed using internal information on anticipated prices for the near-term. In the long-term, electricity price growth patterns were obtained from U.S. DOE/EIA's 2013 Annual Energy Outlook.

b. Residential Energy Sales

Residential energy sales are forecasted using two models, the first of which projects the number of residential customers and the second of which projects kWh usage per customer. The residential energy sales forecast is calculated as the product of the corresponding customer count and usage forecasts.

c. Residential Customer Forecasts

The long-term residential customer forecasting model is linear and monthly. The model for the Indiana service area is depicted as follows:

$$customers = f(grossregionalproductpercapita, mortgagerate, customers_{-1})$$

The service area real gross regional product per capita provides a measure of economic growth in the region, which will affect customer growth. The lagged dependent variable captures the adjustment of customer growth to changes in the economy. There are also binary variables to capture monthly variations in customers, unusual data points and special occurrences.

The customer forecast is blended with the short-term residential customer forecast to produce a final forecast.

d. Residential Energy Usage Per Customer

The residential usage model is estimated using a Statistically Adjusted End-Use Model (SAE), which was developed by Itron, a consulting firm with expertise in energy modeling. This model assumes that use will fall into one of three categories: heat, cool and other. The SAE model constructs variables to be used in an econometric equation like the following:

$$Use = f(Xheat, Xcool, Xother)$$

The Xheat variable is derived by multiplying a heating index variable by a heating use variable. The heating index incorporates information about heating equipment saturation; heating equipment efficiency standards and trends; and thermal integrity and size of homes. The heating use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices, and electricity prices.

The Xcool variable is derived by multiplying a cooling index variable by a cooling use variable. The cooling index incorporates information about cooling equipment saturation; cooling equipment efficiency standards and trends; and thermal integrity and size of homes. The cooling use variable is derived from information related to billing days, heating degree- days, household size, personal income, gas prices, and electricity prices.

The Xother variable estimates the non-weather sensitive sales and is similar to the Xheat and Xcool variables. This variable incorporates information on appliance and equipment saturation levels; average number of days in the billing cycle each month;

average household size; real personal income, gas prices, and electricity prices.

The appliance saturations are based on historical trends from I&M's 2010 residential customer survey. The saturation forecasts are based on DOE forecasts and analysis by Itron. The efficiency trends are based on U.S. Department of Energy (DOE) forecasts and Itron analysis. The thermal integrity and size of homes are for the East North Central Census Region and are based on DOE and Itron data.

The number of billing days is from internal data. Economic and demographic forecasts are from Moody's Analytics and the electricity price forecast is developed internally.

The SAE model is estimated using a linear regression model. It is a monthly model for the period January 1996 through February 2013. This model incorporates the effects of the EPAct, EISA, ARRA and EIEA on residential energy consumption.

The long-term residential energy sales forecast is derived by multiplying the "blended" customer forecast by the usage forecast from the SAE model.

e. Commercial Energy Sales

Long-term commercial energy sales are forecast using a SAE model. This model is similar to the residential SAE model. The functional model is as follows:

$$Energy = f\,(Xheat, Xcool, Xother)$$

As with the residential model, Xheat is determined by multiplying a heating index by a heat use variable. The variables incorporate information on heating degree-days, heating equipment saturation, heating equipment operating efficiencies, square footage, average number of days in a billing cycle, commercial output and electricity price.

The Xcool variable uses measures similar to the Xheat variable, except it uses information on cooling degree-days and cooling equipment, rather than those items related to heating load.

The Xother variable measures the non-weather sensitive commercial load. It uses non-weather sensitive equipment saturations and efficiencies, as well as billing days, commercial output and electricity price information.

The saturation, square footage and efficiencies are from the Itron base of DOE data and forecasts. The saturations and related items are from DOE's *2010 Annual Energy Outlook*. Billing days and electricity prices are developed internally. The commercial output measure is real commercial gross regional product from Moody's Analytics. The equipment stock and square footage information are for the East North Central Census Region.

The SAE is a linear regression for the period January 1996 through February 2013. As with the residential SAE model, the effects of the EPAct 2005, EISA 2007, ARRA and EIEA are captured in this model.

f. Industrial Energy Sales

Industrial energy sales are estimated using a monthly model, which is depicted as follows:

$$Energy = f\,(electricityprice, grpmanufacturing, employment)$$

Service area employment, Federal Reserve Board industrial production indexes for motor vehicles and parts and primary metals, and the service area gross regional product for manufacturing are used as measures of manufacturing activity in the region. Real electricity price for industrial customers is used as I&M's own price measure. In addition binary variables are used for special occurrences.

g. All Other Energy Sales

The all other energy sales category is comprised of public street and highway lighting (PSHL) and sales-for-resale.

The PSHL forecast is a monthly model driven by regional commercial employment, which is a measure of economic expansion in the region and the need for additional lighting.

The wholesale customers forecast are the same as for the short run models. These models are monthly and have the following structure:

$$energy = f(employment, population, output, price, heating, cooling)$$

Each model is driven by the Company's Indiana service area employment, population or gross regional product, which are used as measures of economic growth in the region. Average real electric price for I&M Indiana wholesale customers is use to estimate the effects of price on sales. Heating and cooling degree-days are used to capture the sensitivity to weather of the energy sales.

4. Blending Short-term and Long-term Forecast Results

Values for the portion of the forecast horizon from March 2013 to December 2014 are generally taken from the short-term process. Values for the period of January 2015 to June 2015 are generally obtained by blending the results from the short-term and long-term models. This blending process combines the two forecasts by assigning weights to each forecasted value where these weights transition from favoring the short-term values initially to favoring the long-term values by the end of the blending period. Beyond the blending period, the long-term values are utilized. However, in the case of the Indiana jurisdiction, all of the retail classes and three of the wholesale customers utilized the long-term forecast throughout the forecast horizon in order to best utilize the long-term methodology's capability of anticipating turning points in economic growth.

5. Billed/Unbilled and Losses

a. Billed/Unbilled Analysis

Unbilled energy sales are forecast using the same methodology that is used by the Company to compute actual unbilled sales each month as part of its closing process. The Company starts with the projected monthly internal energy requirements forecast, subtracts the forecasted billed sales and estimate for line losses to derive the forecasted net unbilled sales.

b. Losses and Unaccounted-For Energy

Energy is lost in the transmission and distribution of the product. This loss of energy from the source of production to consumption at the premise is measured as the average ratio of all FERC revenue class energy sales measured at the premise meter to the net internal energy requirements metered at the source. In modeling, Company loss study results are incorporated to apply losses to each revenue class.

D. Forecasting Methodology for Seasonal Peak Internal Demand
(170 IAC 4-7-4(5) and 4-7-5 (a))

The demand forecast model is a series of algorithms for allocating the monthly blended FERC revenue class sales to hourly demand. The inputs into forecasting hourly demand are blended FERC revenue class sales, energy loss multipliers, weather, 24-hour load profiles and calendar information.

The weather profiles are developed from representative weather stations in the service area. Twelve monthly profiles of average daily temperature that best represent the cooling and heating degree-days of the specific geography are taken from the last 30 years of historical values. The consistency of these profiles ensures the appropriate diversity of the company loads.

The 24-hour load profiles are developed from historical hourly company or jurisdictional load and end-use or revenue class hourly load profiles. The load profiles were developed from segregating, indexing and averaging hourly profiles by season, day types (weekend, midweek and Monday/Friday) and average daily temperature ranges. The end-use and class profiles were obtained from Iron, Inc. Energy Forecasting load shape library and modeled to represent each company or jurisdiction service area.

In forecasting, the weather profiles and calendars dictate which profile to apply and the sales plus losses results dictate the volume of energy under the profile. In the end, the profiles are benchmarked to the aggregate energy and seasonal peaks through the adjustments to the hourly load duration curves of the annual 8,760 hourly values. These 8,760 hourly values per year are the forecast load of the individual companies of AEP that can be aggregated by hour to represent load across the spectrum from end-use or revenue classes to total for AEP companies in a RTO or total AEP System. Net internal energy requirements are the sum of these hourly values to a total company energy need basis. Company peak demand is the maximum of the hourly values from a stated period (month, season or year).

E. Base Load Forecast Results

(170 IAC 4-7-5(a) (3) and (6) and (7) (A-C))

Exhibit 3-2 presents I&M's annual internal energy requirements forecasted for the years 2013-2033, and on actual requirements from the years 2003-2013 (with 2013 being part history and part forecast). The requirements are separated by major category (residential commercial, industrial and other internal sales, as well as system losses). The exhibit also shows the average annual growth rates for both the historical and forecast periods. Exhibits 3-3 and 3-4 present the corresponding information for I&M's Indiana and Michigan service areas, respectively. Also, Exhibit 3-5 provides a disaggregation of the forecasted "other internal sales" figures shown on Exhibits 3-2 to 3-4.

Exhibit 3-6 shows, for I&M’s actual and forecasted summer, winter and annual peak demands, along with annual total internal energy requirements. Also shown are the associated growth rates and annual load factors. The forecasts provided in Exhibits 3-2 through 3-6 reflect after the effects of filed demand-side management programs.

F. Impact of Conservation and Demand-Side Management

The impact of past and ongoing customer conservation and load management activities, including DSM programs, is embedded in the historical record of electricity use and, in that sense, is intrinsically reflected in the load forecast. The load impacts of potential expanded DSM installations are analyzed separately and subtracted from the blended sales forecast. That analysis will be provided in Chapter 4 of this report.

G. Forecast Uncertainty and Range of Forecasts

(170 IAC 4-7-4(6) and 170 IAC 4-7-5(b) (2) and (b) (3))

Even though load forecasts are created individually for each of the operating companies in the AEP System–East Zone, and aggregated to form the AEP System–East Zone total, forecast uncertainty is of primary interest at the System level, rather than the operating company level. Thus, regardless of how forecast uncertainty is characterized, the analysis begins with AEP System–East Zone load.

Among the ways to characterize forecast uncertainty are: (1) the establishment of confidence intervals with a given percentage of possible outcomes, and (2) the development of high- and low-case scenarios that demonstrate the response of forecasted load to changes in driving-force variables. I&M continues to support both approaches. However, this report uses scenarios for capacity planning sensitivity analyses.

The first step in producing high- and low-case scenarios was the estimation of an aggregated "mini-model" of AEP System–East Zone internal energy requirements. This approach was deemed more feasible than attempting to calculate high and low cases for each of the many equations used to produce the load forecasts for all operating companies. The mini-model is intended to represent the full forecasting structure employed in producing the base-case forecast for the AEP System–East Zone and, by association, for the Company. The dependent variable is total AEP System–East Zone internal energy requirements, excluding sales to the two aluminum reduction plants in the AEP System–East Zone service area. This aluminum load is a large and volatile component of total load, which is treated judgmentally, not analytically, in the load forecast. It is simply added back to the alternative forecasts produced by the mini-model to create low- and high-case scenarios for total internal energy requirements. The independent variables are real service area gross regional product (GRP), the average real price of electricity to all AEP System–East Zone customer classes, the average real price of natural gas in the seven states served by AEP System–East Zone, and AEP System–East Zone service-area heating and cooling degree-days. Acceptance of this particular specification was based on the usual statistical tests of goodness-of-fit, on the reasonableness of the elasticity's derived from the estimation, and on a rough agreement between the model's load prediction and that produced by the disaggregated modeling approach followed in producing the base load forecast.

Once a base-case energy forecast had been produced with the mini-model, low and high values for the independent variables were determined. The values finally decided upon reflected professional judgment. The low- and high-case growth rates in real GRP for the forecast period were 1.1% and 2.3% per year, respectively, compared to 1.8% for the base case. Real electricity price high and low cases assumed average annual growth rates of 0.5% and 0.3%, respectively. Meanwhile, the base case for real electricity price assumed an average annual growth of 0.4%. Variations in weather were not considered; so the value of heating and cooling degree-days remained the same in all cases.

The low-case, base-case and high-case forecasts of summer and winter peak demands and total internal energy requirements for I&M are tabulated in Exhibit 3-7. Graphical displays of the range of forecasts of internal energy requirements and summer peak demand for I&M are shown in Exhibits 3-8.

For I&M, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2033, represent deviations of about 9% below and 7% above, respectively, the base-case forecast.

H. Performance of Past Load Forecasts

(170 IAC 4-7-4(5))

These exhibits reflect the uncertainty inherent in the forecasting process, and demonstrate the changing perceptions of the future.

The performance of the Company's past load forecasts is reflected in Exhibit 3-9, which displays, in graphical form, annual internal energy requirements and summer peak demands experienced since 1990, along with the corresponding forecasts made in 2001, 2003, 2005, 2007, 2009, 2011and 2013 (the current forecast).

I. Weather-Normalization of Load

(170 IAC 4-7-5(a) (4) and (5))

Exhibit 3-10 compares the recorded (i.e., actual) and weather-normalized summer and winter peak internal demands and annual internal energy requirements for I&M for the last ten years, 2003-2012.

Peak normalization is a fundamental process of evaluating annual or monthly peaks over time, without the impact of "abnormal" weather events and load curtailment events. The limited number of true annual or monthly peaks over time makes it difficult to use traditional regression analysis. So, a regression model is used to determine statistical relationships among a set of daily observations that are similar to annual/monthly peaks and weather conditions. Any load curtailment or significant outage events are added back to the daily observations. The peak normalization demand model is replicated numerous times in a Monte Carlo (stochastic) simulation model. This approach derives probability distributions for both the dependent variable (peak) and independent variables (weather). Multiple estimates for peak are obtained over time that ultimately produces a weather normalized peak.

Similarly, for each year, the weather-normalized internal energy requirements were determined by applying, to each month of the year, an adjustment related to heating or cooling degree-days, as appropriate, to each sector of the recorded internal energy requirements. The adjustment for each sector was obtained as the product of (1) the difference between the service area's expected (or "normal") heating or cooling-degree-days for the month and the actual heating or cooling degree-days for that month and (2) a weather-sensitivity factor (in MWh per heating or cooling degree-day), which was estimated by regressing over the past years monthly sectoral energy requirements against heating or cooling degree-days for the month. The normalized monthly energy requirements thus determined for each sector were then added for all sectors across all twelve months to obtain the net total weather-normalized energy requirements for the year.

J. Historical and Projected Load Profiles

(170 IAC 4-7-4(2) (A), 170 IAC 4-7-5(a) (1) (A), (B), (C) and (D), 170 IAC 4-7-5(a) (2) and (9))

Exhibits 3-11 to 3-14 display various historical and forecasted load profiles pertinent to the planning process. Exhibit 3-11 shows profiles of monthly peak internal demands for I&M on an actual basis for the years 2003 and 2008, and as forecasted for 2013 (includes actual data through August), 2023 and 2033. Exhibit 3-12 shows, for the winter-peak month and summer-peak month for the years 2007 and 2015, respectively, I&M’s average daily internal load shape for each day of the week, along with the peak-day load shape. Exhibit 3-13 displays, for the forecast years 2011 and 2021, I&M’s–East

Zone daily internal load shapes for a simulated week in the winter-peak month (January) and summer-peak month (August). In both cases, a weekday is assumed to represent the day of the monthly (and seasonal) peak. Such load shapes were developed for use in integrated resource planning analyses.

The Company maintains an on-going load research program consisting of samples of each major rate class in each jurisdiction. Exhibit 3-14 displays I&M's Indiana jurisdiction residential, commercial and industrial customer class summer and winter 2012 load shape information derived from these samples.

K. Data Sources

(170 IAC 4-7-4 (1))

The data used in developing the I&M load forecast come from both internal and external sources.

The external sources are varied and include state and federal agencies, as well as Moody's Analytics. Exhibit 3-15 identifies the data series and associated sources, along with notes on adjustments made to the data before incorporation into the load forecast.

L. Changes in Forecasting Methodology

Opportunities to enhance forecasting methods are explored by I&M/AEP on a continuing basis. The forecasts reported herein reflect a limited number of changes in the methodology implemented during the last two years.

M. Load-Related Customer Surveys

(170 IAC 4-7-4(2) and 170 IAC 4-7-4(3))

A residential customer survey was last conducted in the winter of 2013 in which data on end-use appliance penetration and end-use saturation rates were obtained.

Beginning in 1980, in intervals of approximately three years, the Company has regularly surveyed residential customers to monitor customers' demographic characteristics, appliance ownership, penetration of new energy use products and services, and conservation efforts. The 2013 survey was not used in the residential model estimation discussed above, as it was completed and validated at the time the load forecast models were estimated.

The Company has no proposed schedule for industrial and/or commercial customer surveys to obtain end-use information in the near future. I&M monitors its industrial and commercial (and residential) customer end-use consumption patterns through its ongoing load research program.

N. Load Research Class Interval Usage Estimation Methodology

(170 IAC 4-7-4(2)(A) and 170 IAC 4-7-5(9))

This section describes the methodology used to estimate load usage by customer class.

AEP is a participating member of the Association of Edison Illuminating Companies (AEIC) Load Research Committee, was a significant contributor to the AEIC Load Research Manual, and uses the procedures set forth in that manual as a guide for load research practices. AEP maintains an on-going load research program in each retail rate jurisdiction which enables class hourly usage estimates to be derived from actually metered period data for each rate class for each hour of each day. The use of actual period metered data results in the effective capture of weather events and economic factors in the representation of historical usage.

For each rate class in which customer maximum demand is normally less than 1

MW, a statistical random sample is designed and selected to provide at least 10% precision at the 90% confidence level at times of company monthly peak demand. In the sample design process, billing usage for each customer in the class is utilized in conjunction with any available class interval data to determine the optimal stratified sample design using the Dalenius-Hodges stratification procedure. Neyman Allocation is used to determine the necessary number of sample customers in each stratum. All active customers with the requisite data available in the rate class population are included in the sample selection process, which uses a random systematic process to select primary sample points and backup sample points for each primary point.

For selected sample sites that reside within an AMI area, the interval data is extracted from the Meter Data Management System and imported into the ITRON MV90 System. For selected sample sites that reside outside of an AMI area, each location undergoes field review and subsequent installation of an interval data recorder. The recorder is normally set to record usage in fifteen minute intervals. For rate classes in which customer maximum demand is normally 1 MW or greater, each customer in the class is interval metered, and these are referred to as 100% sampled classes. The interval data is retrieved at least monthly, validated through use of the ITRON MV90 System, edited or estimated as necessary, and stored for analytical purposes. The status of each sample point undergoes on-going review and backup sample points replace primary sample points as facilities close, change significant parameters such as rate class, or become unable to provide required information due to safety considerations. This on-going sample maintenance process ensures reasonable sample results are continuously available, and samples are periodically refreshed through a completely new sample design and selection process to capture new building stock and when necessary to capture rate class structure changes.

Prior to analysis, as an additional verification that all interval data is correct, interval data for each customer is summed on a billing month basis and the resulting total energy and maximum demand are compared to billing quantities. Any significant discrepancies between the interval data and the billing quantities are further investigated and corrected, as needed. Rate class analysis is then performed through DNV KEMA's RLW Load Research Analysis System. The sample interval data is post-stratified and weighted to represent the sampled class populations, and total class hourly load estimates are developed. The analysis provides hourly load estimates at both the stratum and class levels, and standard summary statistics, including non-coincident peaks, coincident peaks, coincidence factors, and load factors, at the class, stratum, and sample point levels.

The resulting class hourly load estimates are examined through various graphical approaches, the summary statistics are reviewed for consistency across time, and the monthly sample class energy results are compared against billed and booked billed and accrued values. Any anomalies are investigated, and a rate class analysis may be re-worked if the investigation shows that is necessary. When analysis and review of all rate classes is completed, losses are applied to the hourly rate class estimates, the class values are aggregated, and the resulting total estimate is compared to the company hourly load derived from the system interchange and generation metering. Any significant differences between the customer level load research derived numbers and the system level numbers are investigated, and class results may be re-analyzed, if necessary.

Rate classes are often comprised of combinations of commercial and industrial customers. Separate commercial and industrial hourly load estimates are developed after rate class analysis is completed. Monthly billing usage for each commercial and industrial customer is acquired from the customer information system and is imported into the DNV KEMA's RLW Load Research Analysis System, along with the sample point interval data available from the rate class random and 100% samples. The sample interval data is post-stratified and weighted to represent the commercial and industrial class populations, and total class hourly load estimates are developed. Losses are then applied to the resulting commercial and industrial class estimates, the values are combined with the residential class hourly load estimates from the rate class analysis, the class values are aggregated, and the resulting total estimate is compared to the company hourly load derived from the system interchange and generation metering. Any significant differences between the load research derived numbers and the system level numbers are investigated, and class results may be re-analyzed, if necessary. Final residential, commercial, and industrial class hourly load estimates are provided to the forecasting organization for use in the long-term forecasting and planning process.

O. Customer Self-Generation

(170 IAC 4-7-4(4))

On May 18, 2005, I&M's net metering program became effective for residential and school customers operating small, renewable-resource generation facilities with nameplate capacities of less than or equal to 10 kW. On October 20, 2011, I&M's net metering program was expanded to include all customer classes and the renewable-resource generation facility nameplate capacity limit was increased to 1 MW. Through September 6, 2013, 83 customers have signed up for this program with a total nameplate capacity of approximately 566 kW.

However, customer self-generation (including co-generation) historically has been minimal in the I&M service territory. For a variety of reasons, including the relatively low retail cost of electricity, I&M customers generally have not found self-generation to be cost effective. Thus, the load forecast does not include significant increases to customer self-generation.

However, as discussed in Chapter 4, the costs of customer generation may decline to the point where customers begin to adopt these technologies in significant numbers. This IRP addresses this possibility outside of the load forecast where customer-sited generation is viewed as a resource. Future IRPs may include the impacts of customer owned generation in the load forecast as its acceptance is better understood and predictable.

P. Exhibits 3-1 to 3-15

Exhibit 3-1

Indiana Michigan Power Company
Internal Energy Requirements and Peak Demand Forecasting Method

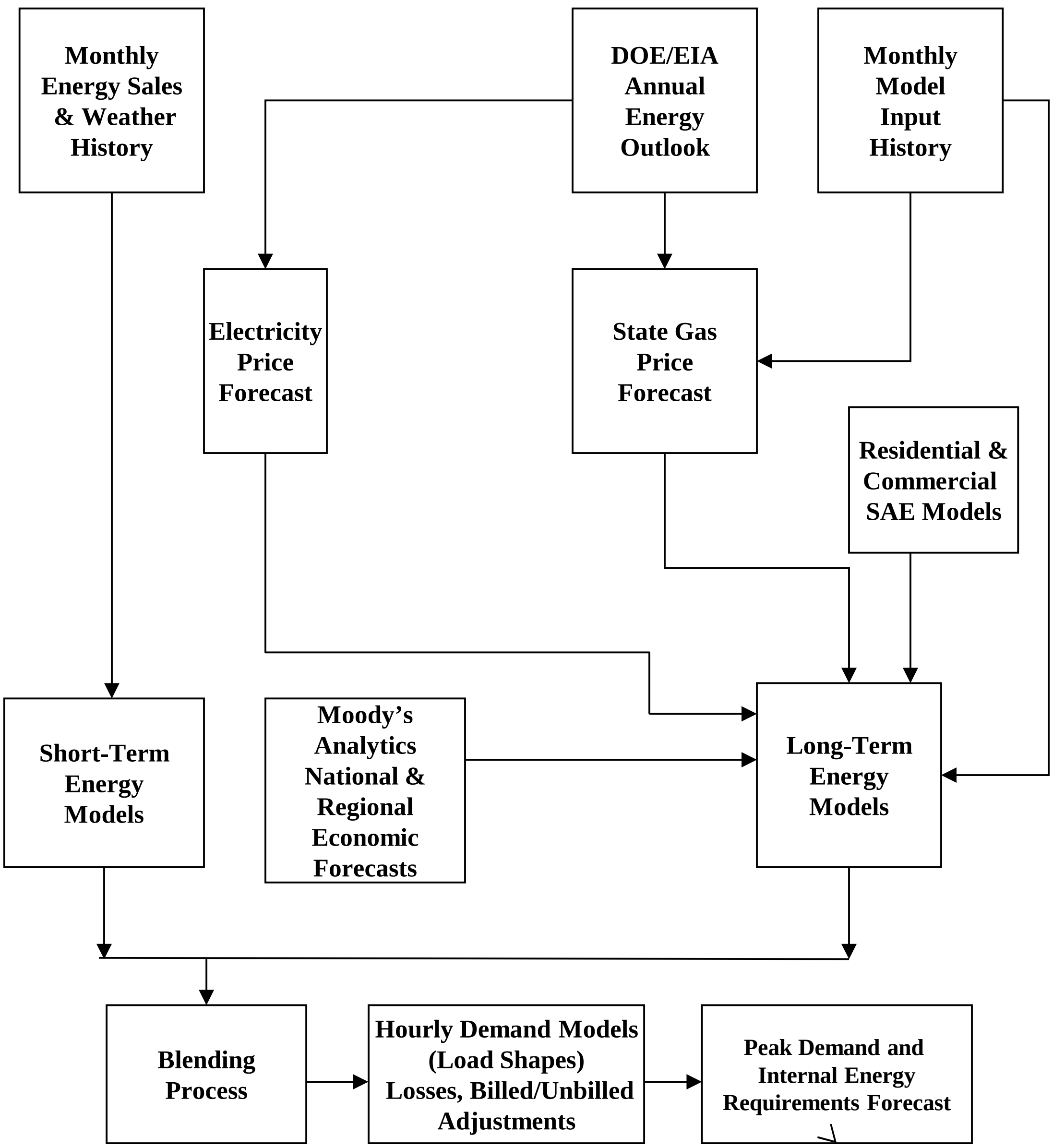


Exhibit 3-2

Indiana Michigan Power Company
Annual Internal Energy Requirements and Growth Rates
2003-2033

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
Year	**GWH**	**% Growth**	**GWH**	**% Growth**	**GWH**	**% Growth**	**GWH**	**% Growth**	**GWH**	**% Growth**	**GWH**	**% Growth**
Actual												
2003	5,476	---	4,777	---	7,878	---	2,542	---	2,191	---	22,865	---
2004	5,524	0.9	4,894	2.4	8,109	2.9	2,757	8.4	1,655	-24.5	22,939	0.3
2005	5,986	8.4	5,090	4.0	8,090	-0.2	2,253	-18.3	1,965	18.7	23,382	1.9
2006	5,784	-3.4	5,068	-0.4	8,049	-0.5	3,580	58.9	1,940	-1.2	24,421	4.4
2007	6,132	6.0	5,373	6.0	7,967	-1.0	4,620	29.1	1,912	-1.5	26,004	6.5
2008	6,059	-1.2	5,272	-1.9	7,536	-5.4	4,629	0.2	1,950	2.0	25,446	-2.1
2009	5,767	-4.8	5,038	-4.4	6,762	-10.3	4,628	0.0	2,102	7.8	24,297	-4.5
2010	6,083	5.5	5,121	1.6	7,445	10.1	4,887	5.6	2,294	9.1	25,829	6.3
2011	5,997	-1.4	5,045	-1.5	7,523	1.0	4,975	1.8	2,388	4.1	25,929	0.4
2012	5,771	-3.8	5,001	-0.9	7,556	0.4	5,112	2.8	2,290	-4.1	25,731	-0.8
2013*	5,775	0.1	4,906	-1.9	7,369	-2.5	5,107	-0.1	2,379	3.9	25,537	-0.8
Forecast												
2014	5,626	-2.6	4,859	-1.0	7,166	-2.8	5,127	0.4	2,117	-11.0	24,894	-2.5
2015	5,574	-0.9	4,842	-0.3	7,115	-0.7	5,164	0.7	2,109	-0.4	24,805	-0.4
2016	5,536	-0.7	4,841	0.0	7,000	-1.6	5,182	0.4	2,099	-0.5	24,657	-0.6
2017	5,503	-0.6	4,837	-0.1	6,882	-1.7	5,244	1.2	2,083	-0.7	24,550	-0.4
2018	5,470	-0.6	4,831	-0.1	6,774	-1.6	5,291	0.9	2,074	-0.5	24,439	-0.5
2019	5,446	-0.4	4,831	0.0	6,704	-1.0	5,356	1.2	2,068	-0.3	24,405	-0.1
2020	5,423	-0.4	4,840	0.2	6,653	-0.8	5,410	1.0	2,063	-0.2	24,388	-0.1
2021	5,415	-0.1	4,859	0.4	6,616	-0.6	5,481	1.3	2,065	0.1	24,436	0.2
2022	5,414	0.0	4,883	0.5	6,595	-0.3	5,538	1.0	2,066	0.1	24,496	0.2
2023	5,419	0.1	4,910	0.6	6,581	-0.2	5,606	1.2	2,071	0.2	24,586	0.4
2024	5,426	0.1	4,938	0.6	6,565	-0.2	5,653	0.8	2,078	0.3	24,660	0.3
2025	5,439	0.2	4,976	0.8	6,551	-0.2	5,720	1.2	2,086	0.4	24,773	0.5
2026	5,456	0.3	5,014	0.8	6,539	-0.2	5,772	0.9	2,093	0.3	24,874	0.4
2027	5,475	0.4	5,053	0.8	6,536	0.0	5,838	1.1	2,102	0.4	25,005	0.5
2028	5,499	0.4	5,092	0.8	6,543	0.1	5,891	0.9	2,109	0.3	25,134	0.5
2029	5,522	0.4	5,130	0.7	6,555	0.2	5,961	1.2	2,124	0.7	25,292	0.6
2030	5,548	0.5	5,167	0.7	6,565	0.2	6,017	0.9	2,136	0.6	25,433	0.6
2031	5,575	0.5	5,201	0.7	6,573	0.1	6,086	1.2	2,147	0.5	25,582	0.6
2032	5,599	0.4	5,230	0.6	6,580	0.1	6,142	0.9	2,156	0.4	25,707	0.5
2033	5,625	0.5	5,257	0.5	6,583	0.0	6,215	1.2	2,167	0.5	25,846	0.5

***Includes 6 months actual and 6 months forecast data.**

Average Annual Growth Rates

	Residential	Commercial	Industrial	Other Internal	Losses	Total
2003-2013	0.5	0.3	-0.7	7.2	0.8	1.1
2014-2033	0.0	0.4	-0.4	1.0	0.1	0.2

Exhibit 3-3

Indiana Michigan Power Company-Indiana
Annual Internal Energy Requirements and Growth Rates
2003-2033

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
Year	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual												
2003	4,329	---	4,044	---	6,825	---	2,194	---	1,852	---	19,243	---
2004	4,378	1.1	4,151	2.7	7,036	3.1	2,403	9.5	1,417	-23.5	19,385	0.7
2005	4,738	8.2	4,306	3.7	7,019	-0.2	1,882	-21.7	1,667	17.7	19,612	1.2
2006	4,580	-3.3	4,302	-0.1	7,024	0.1	2,994	59.1	1,642	-1.5	20,542	4.7
2007	4,871	6.3	4,538	5.5	6,959	-0.9	4,009	33.9	1,625	-1.0	22,002	7.1
2008	4,796	-1.5	4,433	-2.3	6,613	-5.0	4,039	0.7	1,654	1.8	21,535	-2.1
2009	4,548	-5.2	4,234	-4.5	5,977	-9.6	4,052	0.3	1,782	7.7	20,593	-4.4
2010	4,806	5.7	4,305	1.7	6,593	10.3	4,261	5.2	1,946	9.2	21,911	6.4
2011	4,750	-1.2	4,240	-1.5	6,727	2.0	4,352	2.1	1,808	-7.1	21,878	-0.2
2012	4,553	-4.1	4,183	-1.3	6,755	0.4	4,477	2.9	1,937	7.2	21,906	0.1
2013*	4,557	0.1	4,112	-1.7	6,574	-2.7	4,484	0.2	1,953	0.8	21,681	-1.0
Forecast												
2014	4,432	-2.7	4,075	-0.9	6,358	-3.3	4,503	0.4	1,763	-9.8	21,130	-2.5
2015	4,395	-0.8	4,051	-0.6	6,307	-0.8	4,530	0.6	1,756	-0.4	21,039	-0.4
2016	4,367	-0.6	4,048	-0.1	6,190	-1.9	4,543	0.3	1,745	-0.6	20,892	-0.7
2017	4,344	-0.5	4,044	-0.1	6,074	-1.9	4,604	1.3	1,731	-0.8	20,797	-0.5
2018	4,317	-0.6	4,039	-0.1	5,975	-1.6	4,649	1.0	1,722	-0.5	20,701	-0.5
2019	4,296	-0.5	4,039	0.0	5,913	-1.0	4,712	1.4	1,718	-0.2	20,678	-0.1
2020	4,277	-0.4	4,047	0.2	5,865	-0.8	4,763	1.1	1,714	-0.2	20,665	-0.1
2021	4,272	-0.1	4,065	0.4	5,829	-0.6	4,831	1.4	1,716	0.1	20,711	0.2
2022	4,273	0.0	4,085	0.5	5,809	-0.3	4,884	1.1	1,717	0.1	20,769	0.3
2023	4,278	0.1	4,110	0.6	5,799	-0.2	4,950	1.3	1,722	0.3	20,858	0.4
2024	4,285	0.2	4,135	0.6	5,788	-0.2	4,994	0.9	1,728	0.4	20,930	0.3
2025	4,297	0.3	4,169	0.8	5,776	-0.2	5,058	1.3	1,737	0.5	21,037	0.5
2026	4,312	0.3	4,203	0.8	5,766	-0.2	5,107	1.0	1,743	0.4	21,130	0.4
2027	4,330	0.4	4,238	0.8	5,764	0.0	5,169	1.2	1,751	0.5	21,252	0.6
2028	4,350	0.5	4,272	0.8	5,772	0.1	5,219	1.0	1,758	0.4	21,371	0.6
2029	4,371	0.5	4,305	0.8	5,784	0.2	5,285	1.3	1,771	0.7	21,516	0.7
2030	4,393	0.5	4,337	0.8	5,795	0.2	5,337	1.0	1,782	0.6	21,644	0.6
2031	4,415	0.5	4,365	0.6	5,803	0.1	5,403	1.2	1,792	0.6	21,779	0.6
2032	4,437	0.5	4,389	0.5	5,810	0.1	5,455	1.0	1,800	0.4	21,890	0.5
2033	4,459	0.5	4,411	0.5	5,813	0.1	5,524	1.3	1,809	0.5	22,016	0.6

*Includes 6 months actual and 6 months forecast data.

Average Annual Growth Rates												
2003-2013		0.5		0.2		-0.4		7.4		0.5		1.2
2014-2033		0.0		0.4		-0.5		1.1		0.1		0.2

Exhibit 3-4

Indiana Michigan Power Company-Michigan
Annual Internal Energy Requirements and Growth Rates
2003-2033

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
Year	**GWH**	**% Growth**	**GWH**	**% Growth**	**GWH**	**% Growth**	**GWH**	**% Growth**	**GWH**	**% Growth**	**GWH**	**% Growth**
Actual												
2003	1,147	---	733	---	1,054	---	348	---	338	---	3,621	---
2004	1,146	-0.2	743	1.2	1,074	1.9	354	1.7	238	-29.8	3,554	-1.9
2005	1,247	8.9	784	5.5	1,071	-0.2	370	4.5	298	25.2	3,770	6.1
2006	1,204	-3.5	766	-2.3	1,025	-4.3	585	58.1	299	0.4	3,879	2.9
2007	1,261	4.7	835	9.0	1,009	-1.6	610	4.3	287	-4.0	4,001	3.2
2008	1,262	0.1	839	0.5	923	-8.5	590	-3.3	297	3.4	3,911	-2.3
2009	1,218	-3.5	804	-4.1	785	-15.0	576	-2.4	321	8.0	3,704	-5.3
2010	1,277	4.8	816	1.4	852	8.5	626	8.6	348	8.6	3,918	5.8
2011	1,248	-2.3	805	-1.3	796	-6.6	623	-0.4	580	66.6	4,051	3.4
2012	1,217	-2.4	818	1.7	802	0.8	635	1.9	353	-39.2	3,825	-5.6
2013*	1,218	0.1	794	-3.0	795	-0.8	623	-1.9	426	20.8	3,856	0.8
Forecast												
2014	1,193	-2.0	784	-1.3	808	1.7	624	0.1	355	-16.7	3,764	-2.4
2015	1,179	-1.2	791	0.9	808	0.0	633	1.5	353	-0.4	3,765	0.0
2016	1,168	-0.9	793	0.3	810	0.2	640	1.0	354	0.2	3,765	0.0
2017	1,159	-0.8	793	0.0	808	-0.2	641	0.2	352	-0.5	3,753	-0.3
2018	1,153	-0.5	792	-0.1	800	-1.0	642	0.1	351	-0.3	3,738	-0.4
2019	1,150	-0.3	792	0.0	792	-1.0	644	0.3	350	-0.4	3,727	-0.3
2020	1,146	-0.3	793	0.1	788	-0.4	647	0.5	349	-0.3	3,723	-0.1
2021	1,143	-0.3	795	0.3	787	-0.1	650	0.5	349	0.0	3,724	0.0
2022	1,141	-0.1	797	0.3	786	-0.2	653	0.5	349	0.0	3,726	0.1
2023	1,141	-0.1	800	0.4	782	-0.4	656	0.4	349	0.0	3,728	0.0
2024	1,141	0.0	803	0.4	778	-0.6	659	0.4	349	0.1	3,730	0.1
2025	1,142	0.1	807	0.5	774	-0.4	662	0.5	350	0.1	3,736	0.2
2026	1,144	0.2	811	0.5	772	-0.3	665	0.5	350	0.1	3,743	0.2
2027	1,146	0.2	815	0.5	771	-0.1	669	0.5	351	0.2	3,752	0.2
2028	1,149	0.3	820	0.5	771	0.0	672	0.5	351	0.1	3,763	0.3
2029	1,152	0.3	825	0.6	771	-0.1	676	0.5	353	0.4	3,776	0.3
2030	1,156	0.3	830	0.6	770	0.0	679	0.5	354	0.4	3,790	0.4
2031	1,160	0.3	836	0.7	770	0.0	683	0.6	355	0.4	3,804	0.4
2032	1,163	0.3	841	0.6	770	0.0	687	0.6	357	0.3	3,817	0.3
2033	1,166	0.2	846	0.6	770	0.0	691	0.5	358	0.3	3,830	0.3

***Includes 6 months actual and 6 months forecast data.**

Average Annual Growth Rates

	Residential	Commercial	Industrial	Other Internal	Losses	Total
2003-2013	0.6	0.8	-2.8	6.0	2.3	0.6
2014-2033	-0.1	0.4	-0.3	0.5	0.0	0.1

Exhibit 3-5

Indiana Michigan Power Company
Composition of Forecast of Other Internal Sales (GWh)
2014-2033

	Indiana					Michigan				Total Company				
		Internal Sales for Resale					Internal Sales for Resale				Internal Sales for Resale			
Year	Street Lighting	Coop.	Muni.	IMPA	Total	Street Lighting	Muni.	Coop.	Total	Street Lighting	Muni.	Coop.	IMPA	Total
2014	60	1,261	1,550	1,631	4,503	11	613	0	624	71	2,163	1,261	1,631	5,127
2015	60	1,223	1,566	1,681	4,530	11	622	0	633	71	2,188	1,223	1,681	5,164
2016	59	1,194	1,572	1,717	4,543	11	629	0	640	70	2,201	1,194	1,717	5,182
2017	59	1,206	1,571	1,767	4,604	11	630	0	641	70	2,201	1,206	1,767	5,244
2018	59	1,217	1,571	1,803	4,649	11	631	0	642	69	2,202	1,217	1,803	5,291
2019	58	1,229	1,572	1,853	4,712	11	633	0	644	69	2,206	1,229	1,853	5,356
2020	58	1,241	1,576	1,889	4,763	10	636	0	647	68	2,212	1,241	1,889	5,410
2021	58	1,255	1,579	1,939	4,831	10	640	0	650	68	2,219	1,255	1,939	5,481
2022	57	1,271	1,581	1,975	4,884	10	643	0	653	68	2,224	1,271	1,975	5,538
2023	57	1,285	1,583	2,025	4,950	10	646	0	656	68	2,229	1,285	2,025	5,606
2024	57	1,297	1,585	2,055	4,994	10	649	0	659	67	2,233	1,297	2,055	5,653
2025	57	1,310	1,586	2,105	5,058	10	652	0	662	67	2,238	1,310	2,105	5,720
2026	57	1,322	1,587	2,140	5,107	10	655	0	665	67	2,242	1,322	2,140	5,772
2027	57	1,334	1,588	2,191	5,169	10	658	0	669	67	2,247	1,334	2,191	5,838
2028	57	1,347	1,589	2,226	5,219	10	662	0	672	67	2,251	1,347	2,226	5,891
2029	57	1,362	1,590	2,276	5,285	10	666	0	676	67	2,256	1,362	2,276	5,961
2030	57	1,377	1,591	2,312	5,337	10	669	0	679	67	2,260	1,377	2,312	6,017
2031	57	1,392	1,592	2,362	5,403	10	673	0	683	67	2,265	1,392	2,362	6,086
2032	57	1,407	1,594	2,397	5,455	10	677	0	687	67	2,270	1,407	2,397	6,142
2033	57	1,425	1,595	2,447	5,524	10	680	0	691	67	2,275	1,425	2,447	6,215

Exhibit 3-6

Indiana Michigan Power Company
Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor
2003-2033

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2003	08/21/03	4,223	---	01/07/03	3,683	---	4,223	---	22,865	---	61.8
2004	07/22/04	4,016	-4.9	01/22/04	3,465	-5.9	4,016	-4.9	22,939	0.3	65.0
2005	08/03/05	4,193	4.4	01/28/05	3,465	0.0	4,193	4.4	23,382	1.9	63.7
2006	07/31/06	4,650	10.9	12/08/05	3,537	2.1	4,650	10.9	24,421	4.4	60.0
2007	08/07/07	4,528	-2.6	02/06/07	3,945	11.5	4,528	-2.6	26,004	6.5	65.6
2008	07/31/08	4,264	-5.8	01/25/08	3,875	-1.8	4,264	-5.8	25,446	-2.1	67.9
2009	06/25/09	4,262	0.0	01/15/09	3,728	-3.8	4,262	0.0	24,297	-4.5	65.1
2010	07/23/10	4,474	5.0	12/10/09	3,858	3.5	4,474	5.0	25,829	6.3	65.9
2011	07/21/11	4,837	8.1	12/13/10	3,785	-1.9	4,837	8.1	25,929	0.4	61.2
2012	07/06/12	4,726	-2.3	01/20/12	3,686	-2.6	4,726	-2.3	25,731	-0.8	62.0
2013*	09/10/13	4,544	-3.9	01/22/13	3,782	2.6	4,427	-6.3	25,537	-0.8	65.9
Forecast											
2014		4,393	-3.3		3,763	-0.5	4,393	-0.8	24,894	-2.5	64.7
2015		4,372	-0.5		3,756	-0.2	4,372	-0.5	24,805	-0.4	64.8
2016		4,337	-0.8		3,717	-1.0	4,337	-0.8	24,657	-0.6	64.9
2017		4,328	-0.2		3,712	-0.1	4,328	-0.2	24,550	-0.4	64.7
2018		4,315	-0.3		3,692	-0.5	4,315	-0.3	24,439	-0.5	64.7
2019		4,312	-0.1		3,682	-0.3	4,312	-0.1	24,405	-0.1	64.6
2020		4,306	-0.1		3,665	-0.5	4,306	-0.1	24,388	-0.1	64.7
2021		4,329	0.5		3,680	0.4	4,329	0.5	24,436	0.2	64.4
2022		4,346	0.4		3,686	0.2	4,346	0.4	24,496	0.2	64.3
2023		4,361	0.4		3,698	0.3	4,361	0.4	24,586	0.4	64.4
2024		4,369	0.2		3,694	-0.1	4,369	0.2	24,660	0.3	64.4
2025		4,404	0.8		3,720	0.7	4,404	0.8	24,773	0.5	64.2
2026		4,427	0.5		3,732	0.3	4,427	0.5	24,874	0.4	64.1
2027		4,454	0.6		3,747	0.4	4,454	0.6	25,005	0.5	64.1
2028		4,475	0.5		3,754	0.2	4,475	0.5	25,134	0.5	64.1
2029		4,512	0.8		3,787	0.9	4,512	0.8	25,292	0.6	64.0
2030		4,542	0.7		3,805	0.5	4,542	0.7	25,433	0.6	63.9
2031		4,572	0.7		3,824	0.5	4,572	0.7	25,582	0.6	63.9
2032		4,589	0.4		3,826	0.1	4,589	0.4	25,707	0.5	63.9
2033		4,629	0.9		3,856	0.8	4,629	0.9	25,846	0.5	63.7

***Total energy requirements reflect 6 months actual and 6 months forecast data. The summer peak reflects actual peak through mid-September.**

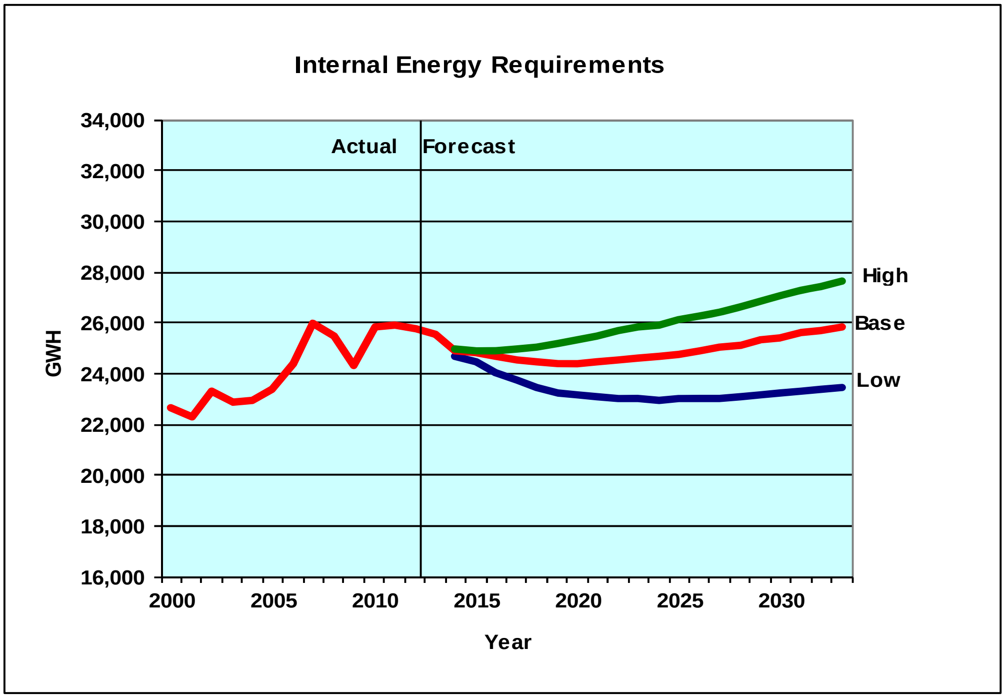
Exhibit 3-7

Indiana Michigan Power Company
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements

	Winter Peak Internal Demands (MW)			Summer Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base Case	High Case
2014	3,731	3,763	3,777	4,356	4,393	4,410	24,683	24,894	24,986
2015	3,700	3,756	3,772	4,307	4,372	4,391	24,436	24,805	24,917
2016	3,627	3,717	3,751	4,231	4,337	4,376	24,057	24,657	24,881
2017	3,589	3,712	3,776	4,185	4,328	4,403	23,736	24,550	24,974
2018	3,543	3,692	3,783	4,141	4,315	4,421	23,458	24,439	25,044
2019	3,510	3,682	3,800	4,110	4,312	4,450	23,263	24,405	25,185
2020	3,474	3,665	3,805	4,083	4,306	4,471	23,121	24,388	25,323
2021	3,472	3,680	3,840	4,085	4,329	4,519	23,057	24,436	25,504
2022	3,463	3,686	3,860	4,083	4,346	4,551	23,016	24,496	25,655
2023	3,459	3,698	3,881	4,079	4,361	4,577	22,996	24,586	25,802
2024	3,442	3,694	3,885	4,070	4,369	4,594	22,974	24,660	25,931
2025	3,452	3,720	3,918	4,087	4,404	4,639	22,992	24,773	26,097
2026	3,451	3,732	3,938	4,095	4,427	4,671	23,004	24,874	26,244
2027	3,453	3,747	3,960	4,105	4,454	4,707	23,045	25,005	26,425
2028	3,448	3,754	3,975	4,110	4,475	4,739	23,085	25,134	26,615
2029	3,468	3,787	4,018	4,132	4,512	4,787	23,164	25,292	26,833
2030	3,476	3,805	4,044	4,149	4,542	4,828	23,234	25,433	27,033
2031	3,484	3,824	4,072	4,166	4,572	4,869	23,310	25,582	27,241
2032	3,479	3,826	4,082	4,173	4,589	4,896	23,378	25,707	27,425
2033	3,500	3,856	4,123	4,202	4,629	4,950	23,462	25,846	27,639
Average Annual Growth Rate % - 2014-2033									
	-0.3	0.1	0.5	-0.2	0.3	0.6	-0.3	0.2	0.5

Exhibit 3-8

Indiana Michigan Power Company
Range of Forecasts



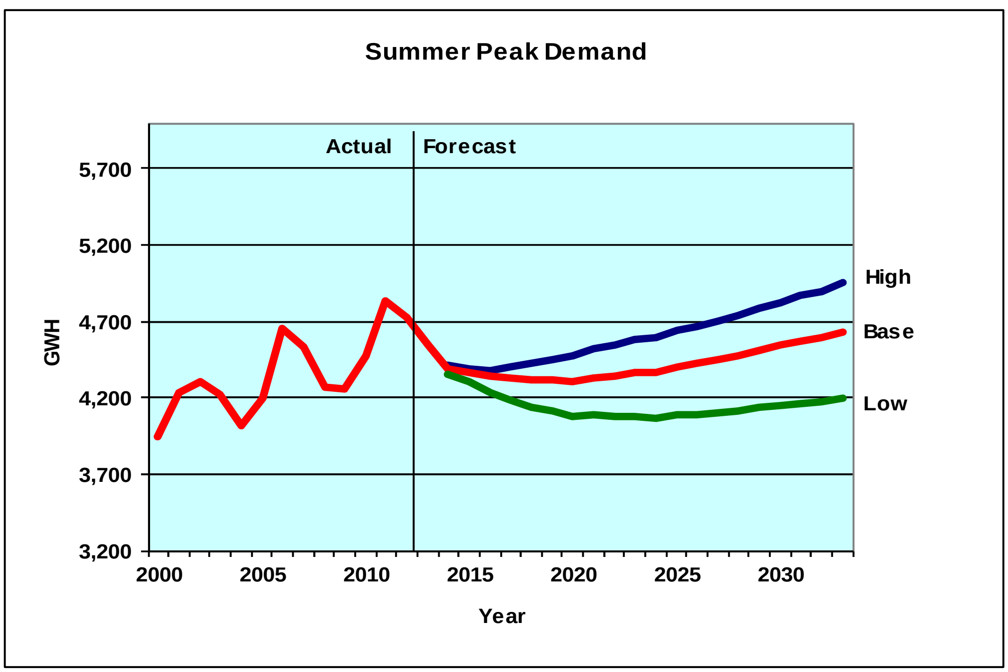
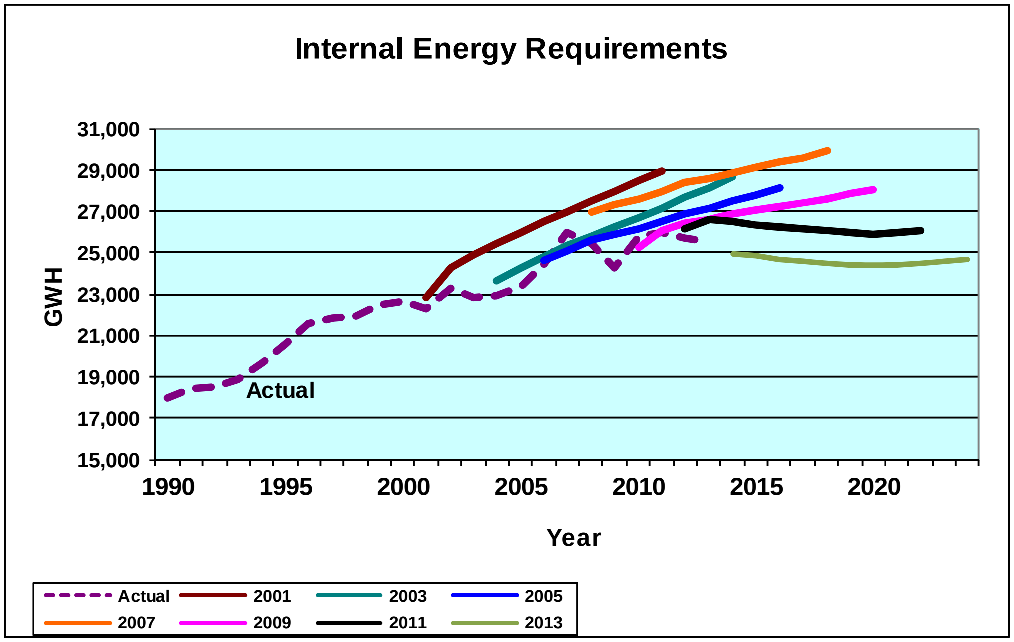


Exhibit 3-9

**INDIANA MICHIGAN POWER COMPANY
COMPARISON OF FORECASTS**



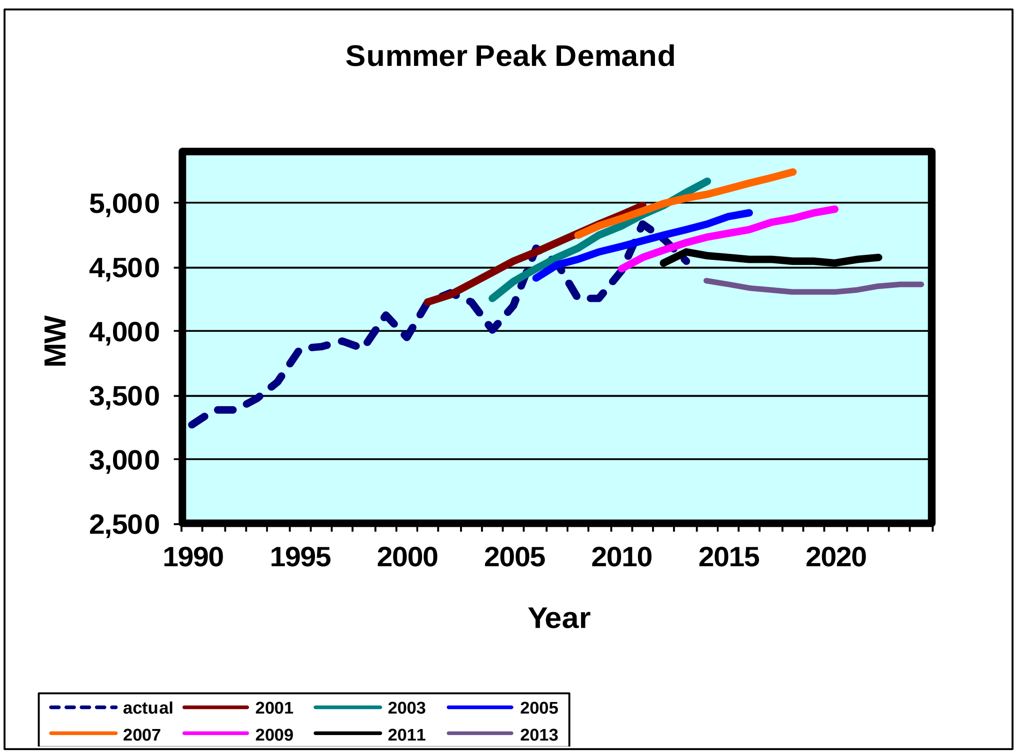


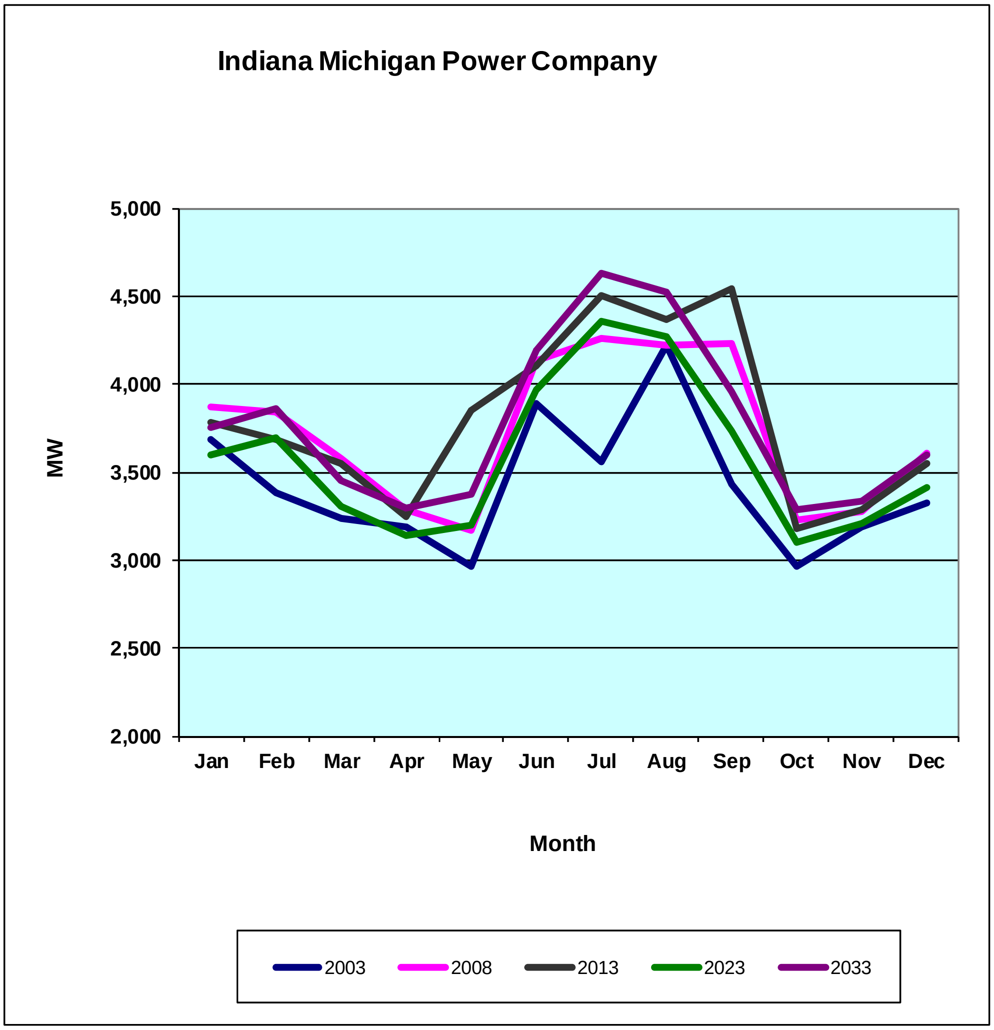
Exhibit 3-10

Indiana Michigan Power Company
Recorded and Weather Normalized Peak Load (MW) and Energy (GWh)
2003-2012

		2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Indiana Michigan Power Company											
A.	**Peak Load - Summer**										
	1. Recorded	4,223	4,016	4,193	4,650	4,528	4,264	4,262	4,474	4,837	4,726
	2. Weather - Normalized	4,168	4,158	4,234	4,373	4,568	4,445	4,275	4,472	4,452	4,561
B.	**Peak Load - Preceding Winter**										
	1. Recorded	3,683	3,465	3,465	3,537	3,945	3,875	3,728	3,858	3,785	3,686
	2. Weather - Normalized	3,568	3,522	3,480	3,600	3,741	3,880	3,621	3,829	3,821	3,785
C.	**Energy**										
	1. Recorded	22,865	22,939	23,382	24,421	26,004	25,446	24,297	25,829	25,929	25,731
	2. Weather - Normalized	23,118	23,254	23,114	24,771	25,779	25,475	24,628	25,456	25,651	25,627

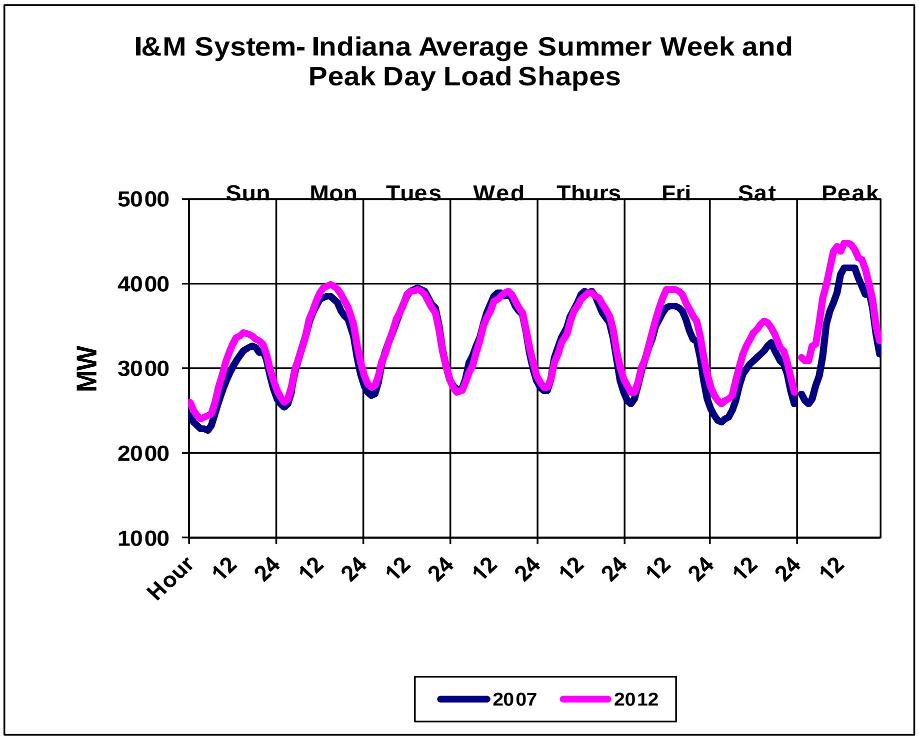
Exhibit 3-11

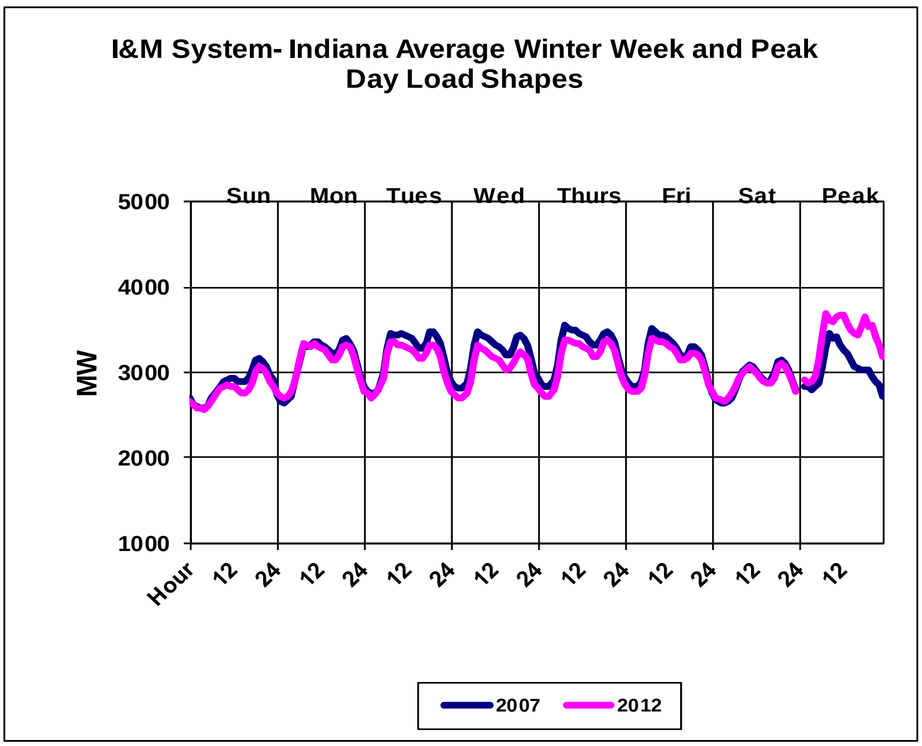
Indiana Michigan Power Company
Profiles of Monthly Peak Internal Demands
2003, 2008, 2013* (Actual)
2023 and 2033



***Data for 2013 include nine months actual and three month forecast.**

Exhibit 3-12


I&M System- Indiana Average Summer Week and Peak Day Load Shapes
Sun
Mon
Tues
Wed
Thurs
Fri
Sat
Peak
5000
4000
3000
2000
1000
MW
Hour
12
24
2007
2012


I&M System- Indiana Average Winter Week and Peak Day Load Shapes
Sun
Mon
Tues
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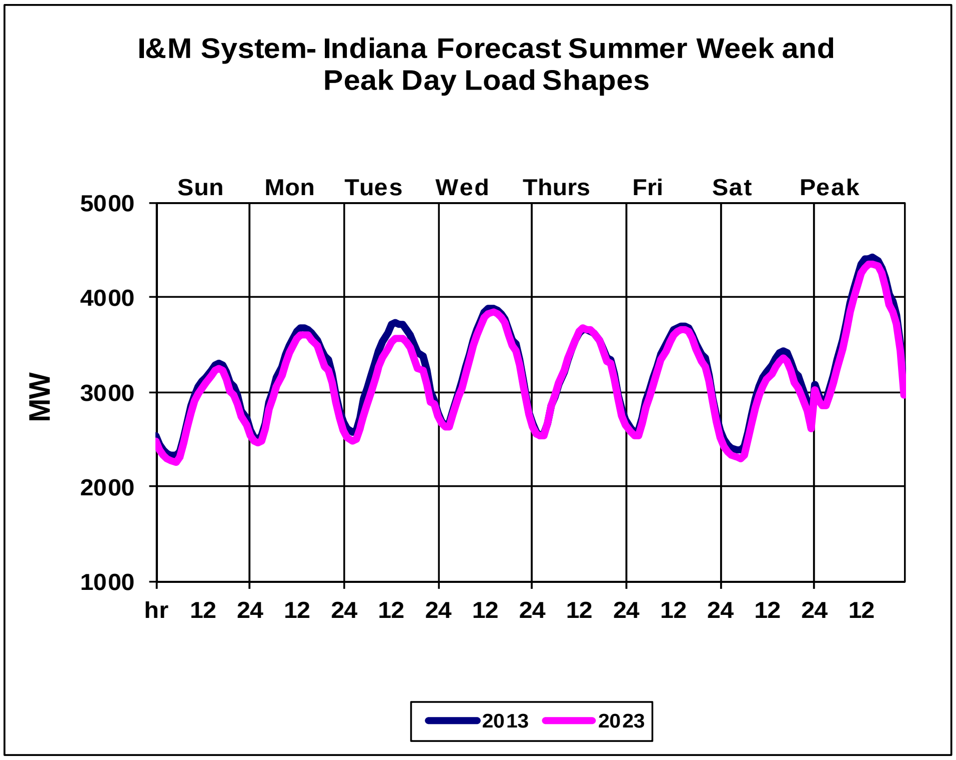
MW
Hour
12
24
2007
2012

Exhibit 3-13


I&M System- Indiana Forecast Summer Week and Peak Day Load Shapes
Sun
Mon
Tues
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Peak
MW
5000
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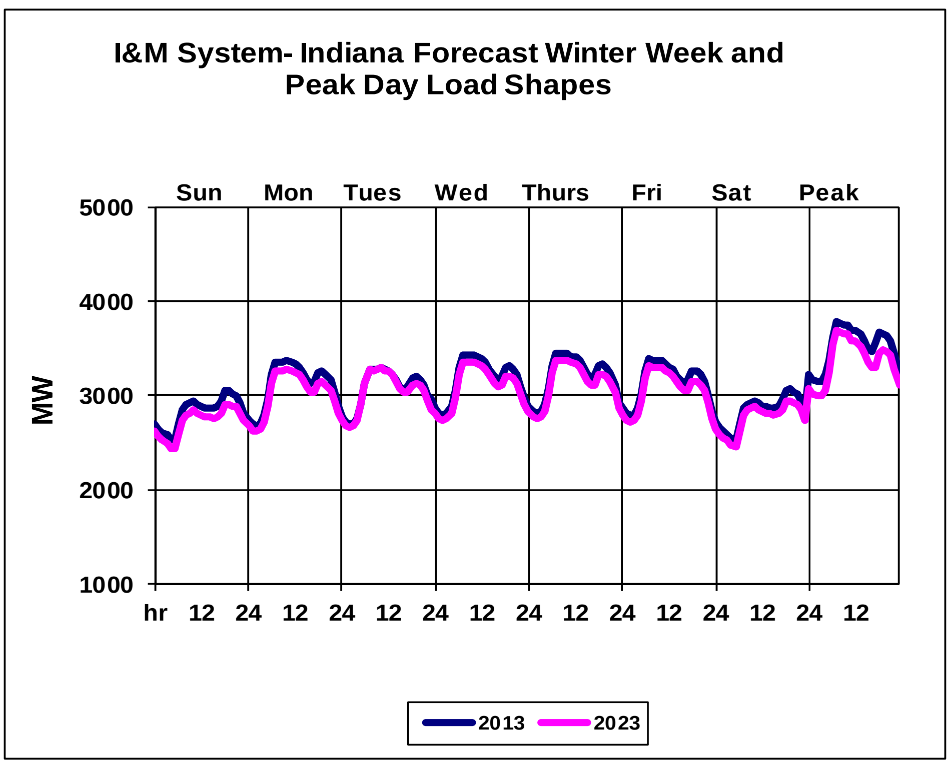
hr 12 24 12 24 12 24 12 24 12 24 12 24 12 24 12
2013
2023


I&M System- Indiana Forecast Winter Week and Peak Day Load Shapes
Sun
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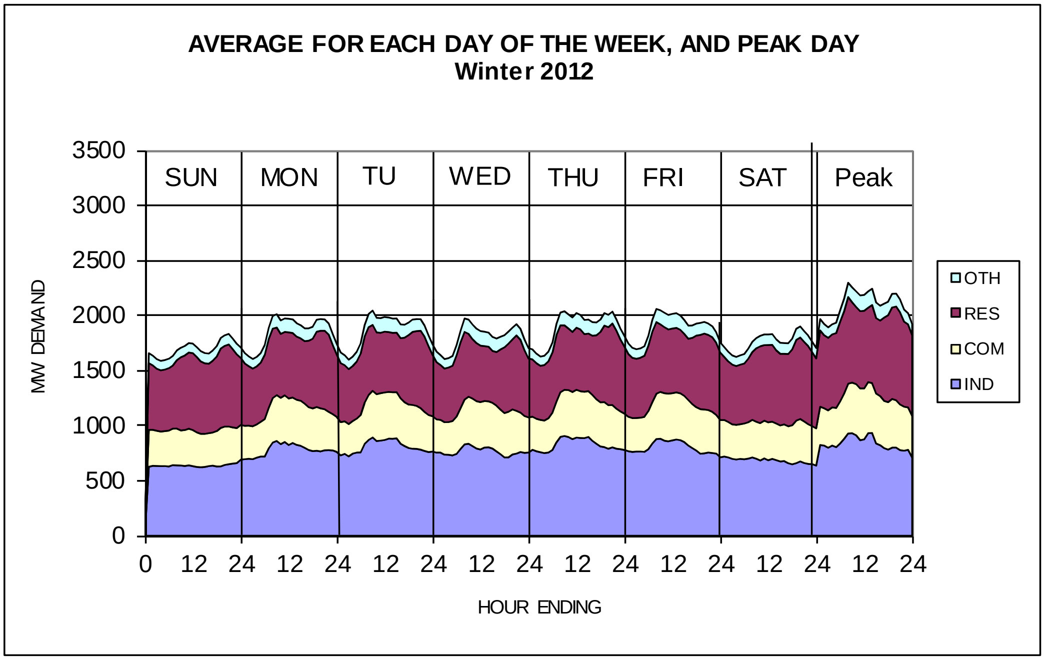
hr 12 24 12 24 12 24 12 24 12 24 12 24 12 24 12
2013
2023

Exhibit 3-14

I&M - INDIANA JURISDICTION
HOURLY DEMAND BY CLASS



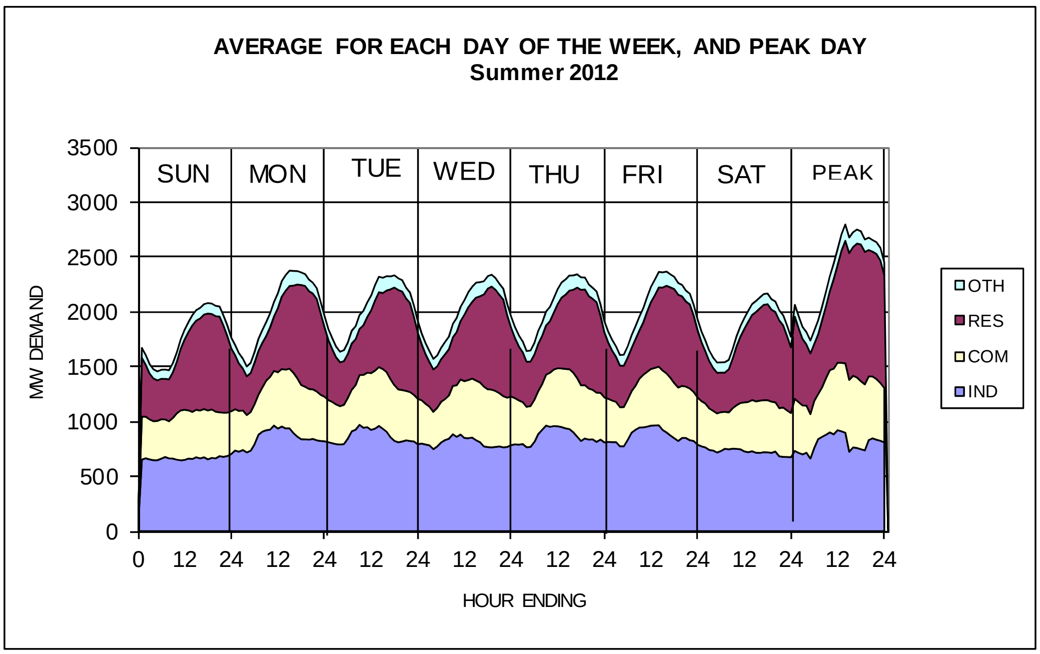


Exhibit 3-15

INDIANA MICHIGAN POWER COMPANY LOAD FORECAST
DATA SOURCES OUTSIDE THE COMPANY

DATA SERIES	FREQUENCY	GEOGRAPHIC	INTERVAL	SOURCE	ADJUSTMENT
Average Daily Temperatures at time of Daily Peak Load	Daily	Selected weather stations throughout the AEP System	1984-2012	NOAA (1) Weather Bank	None
Heating and Cooling Degree-Days	Monthly	Selected weather stations throughout the AEP System	1/84-2/13	NOAA (1) Weather Bank	
Gross Regional Product, Manufacturing	Monthy	U. S.	1984-2042	Moody's Analytics (2)	None
Implicit Deflator-Gross Domestic Product	Monthly	U. S.	1980-2042	Moody's Analytics (2)	
U.S. Gas Prices, U.S. Gas Consumption	Monthly	U.S.	1980-2042	DOE/EIA (6)	Growth rates used for forecast with historical data, extrapolated forecast
Federal Reserve Board Industrial Production Indexes - Selected Industries	Monthly	U. S.	1975-2042	Moody's Analytics (2) FRB (3)	Annual averages used in long-term models
Residential Appliance Efficiencies, Saturation Trends, Housing Size	Annual, Monthly	East North Central Census Region	1995-2042	DOE via Itron(7) Itron	Extrapolated projections, applied trends to Company Saturations
Commericial Equipment Efficiencies, Saturations Square-Footage	Annual, Monthly	East North Central Census Region	1995-2042	DOE via Itron(8) Itron	Extrapolated projections
U. S., Indiana and Michigan Natural Gas Prices by Sector	Monthly	U. S.	1980-2012	DOE/EIA (4)	None
Gross Regional Product	Monthly	Selected Indiana and Michigan Counties	1980-2042	Moody's Analytics (5)	None
Employment (Total and Selected Sectors), Personal Income and Population	Monthly	Selected Indiana and Michigan Counties	1980-2042	Moody's Analytics (5)	None

Source Citations:
(1) "Local Climatological Data," National Oceanographic and Atmospheric Administration.
(2) December 2012 Forecast, Moody's Analytics
(3) Board of Governors of Federal Reserve System, "Federal Reserve Statistical Release," 1975-2012
(4) U. S. Department of Energy/Energy Information Administration "Natural Gas Monthly," Selected Issues.
(5) December 2012 Regional Forecast, Moody's Analytics
(6) U.S. Department of Energy/Energy Information Administration "Annual Energy Outlook 2013 with Projections to 2040" Early release.
(8) Itron June 2012, DOE "Annual Energy Outlook 2012"
(7) Itron July 2012 DOE "Annual Energy Outlook 2012"

4) Demand Side Management

(170 IAC 4-7-6(a) (7); 4-7-6(b); 4-7-7(b) through (f))

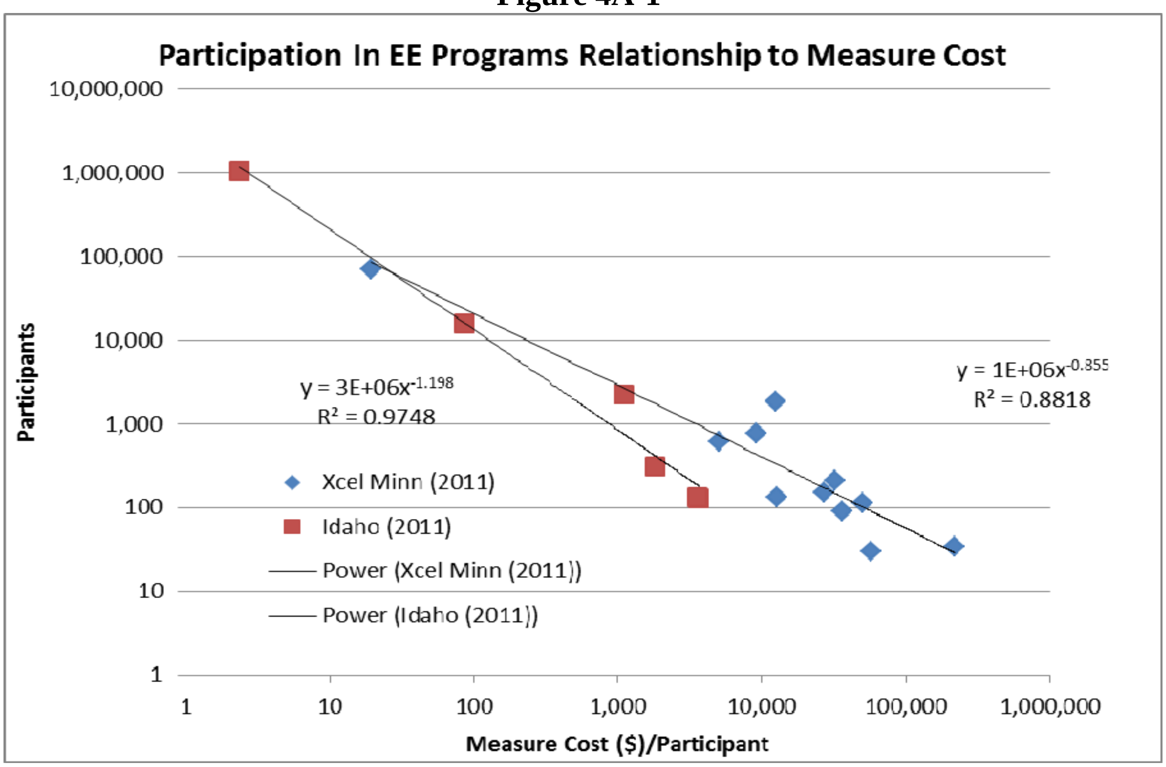
A. Introduction

I&M currently offers a variety of conservation and DSM programs designed to encourage and influence customers to become more aware of their consumption levels, use electricity more efficiently, conserve energy, and use appropriately incentivized, cost-effective electro-technologies. The load impacts associated with the past, current, and future implementation of these programs, are embedded in I&M's actual load experience and its load forecast.

The energy efficiency landscape has changed considerably since the Commission issued its Phase II Generic Order, Cause No. 42693, in December 2009. At this time, substantially all of the lighting standards included in the EISA 2007 have been phased in. EISA 2007 requires that screw-in lighting be 25% more efficient than traditional incandescent lights by the end of 2013 which has resulted in the typical 100, 75, and 60 watt incandescent light bulbs being phased out. Compact Fluorescent Lamp (CFL) bulbs, as part of an energy efficiency program, may still represent savings over the increased standard, as there are some substitutes, notably, efficient halogens. However, by year-end 2019, the standard increases to preclude any substitutes, and the CFL bulb becomes the de facto standard. Similarly, the commercial T-12 light has been prohibited from manufacture or import since mid-2012. Replacing T-12 lights with T-8 lights has constituted the bulk of commercial lighting programs nationwide but eventually, as old stock is consumed, will no longer be considered as an option for utility lighting programs. The long-term load forecast recognizes this and assumes all lighting will be at the mandated standards. This makes any capacity savings associated with traditional lighting programs short-lived, as they become implicit in the load forecast.

As a result, the programs that have constituted the foremost basis of utility energy efficiency programs nationwide, namely residential and commercial lighting programs, have, and will continue to have absent any new market transforming technologies, diminished basis, effectiveness, and impact. While that eventuality was not wholly unforeseen, viable substitute programs that have the same "bang-for-the-buck" and resultant popularity with consumers have not materialized. More generally, the single biggest hurdle to participation is the cost of the measure. **Figure 4A-1** shows this relationship for two separate utilities for which data were available. The lower cost programs consist primarily of lighting and other high bang-for-the-buck, low-cost measures. A similarly inexpensive, highly cost-effective technology has yet to emerge.

Figure 4A-1



With lighting programs de-emphasized, the prospects for reaching the levels contemplated in the Indiana Phase II order are diminished and the load forecast reflects I&M's current estimate of what is likely achievable.

B. Current DSM Programs

I&M currently offers fifteen energy efficiency programs, five of which are statewide Core Programs as required by the Phase II Generic Order (Cause No. 42693). The remaining ten are Core Plus Programs administered by I&M. 2013 represents the final year of I&M's Three Year DSM Plan approved by the IURC in Cause No. 43959. I&M filed a one year 2014 DSM Plan in Cause No. 43827 DSM 3 on July 1, 2013 to bridge I&M's authority to offer and fund such programs until the next multi-year plan filed during 2014. In 2013, the IURC granted a one year extension of the Core Program Third Party Administrator (TPA) and Evaluation, Measurement, and Verification (EM&V) Administrator contracts through 2014 to allow for Core program performance to be fully understood. I&M correspondingly filed its one year 2014 DSM Plan as a result, in lieu of the three year plan (2014-2016) required by the Phase II Generic Order to be filed in 2013. The 2014 DSM Plan carried forth the same programs operated in 2013, requested authority to add two new programs, the Residential EE Products Program and the Electric Energy Consumption Optimization Program (EECO, a/k/a Volt Var or VVO), and proposed a revised forecasting method based on past portfolio and program performance, called the Forecast Expected Performance. The filing also provided the same state mandated goal compliance forecast as well, providing the Commission a balanced view for comparison perspective. I&M's actual program experience from 2010 through October 2013 has been similar to the typical program performance seen nationwide, depicted and described by the graph at the beginning of this section, where lighting, in both the residential and C&I sectors, constitutes the primary end use measure purchased by customers. Since both the existing energy savings effects and future potential from lighting measures are diminishing, as described in Section 1 by the changing federal lighting standards (EISA 2007), I&M is actively seeking new market transforming technologies and programs to supplant the reliance on lighting as the foundation for its DSM and EE programs. However, as few such technologies have emerged, I&M recognizes that its ability to deliver similarly cost effective programs will be challenged for the foreseeable future. As such, and to the extent that other technologies' energy efficiency baselines are increasing as well (e.g., residential and commercial/industrial building codes), the cost to provide energy efficiency programs in pursuit of the state mandated goals from Cause No. 42693 will undoubtedly increase and I&M's portfolio of technologies offered and incented will change and evolve. A list of programs currently offered by I&M is below:

- Residential Lighting
- Home Energy Audit
- Income Qualified Weatherization
- Energy Efficient Schools
- C&I Prescriptive
- Residential Appliance Recycling
- Residential Online Audit

- Residential Home Energy Reports
- Residential Weatherization
- Residential Peak Reduction
- C&I Custom
- C&I Retro Commissioning Lite
- C&I HVAC & Refrigeration
- C&I Audit
- Renewables & Demonstrations

Additional offerings proposed and planned for 2014 include:

- Residential EE Products
- Electric Energy Consumption Optimization

C. I&M Demand-Side Management Status

In both I&M's Indiana and Michigan jurisdictions, annual energy efficiency targets have been mandated (Enrolled Senate Bill 213 – Michigan, Cause No. 42693 Phase II Generic Order – Indiana). The Michigan requirement, which took effect in late 2008 seeks to achieve 10.55% of installed energy savings by 2020 while the Indiana requirement, which began in 2010, seeks to achieve 11.9% installed energy efficiency by 2019.

To that end, this plan reflects current program impacts as well as impacts from as yet undefined future programs but at levels required for forecasted expected performance in Indiana and target compliance in Michigan. Impacts are modeled based on load shapes that best replicate current and likely future programs. Prospective program composition is extrapolated from the current mix of programs and measures. The ultimate mix of Indiana programs will be determined through the collaborative process of the I&M Program Implementation Oversight Board, the DSM Coordination Committee, the State-wide Third Party Administrator and the Commission. The ultimate mix of Michigan programs will also be determined through collaboration with the Michigan Public Service Commission and its Staff.

To achieve the goals in both jurisdictions, a mix of traditional consumer programs and smart grid technologies will likely be necessary and both are considered in this IRP.

D. Program Types

1. Consumer Programs

Energy efficiency measures save money for customers billed on a “per kilowatt-hour” usage basis. The trade-off is reduced volumetric utility charges on the customer bill for any conservation created through either behavioral change, more efficient consumption, or any up-front investment in a building/appliance/equipment modification, upgrade, or any new technology that produces a change in the utility load shape through its deployment. On the participatory side, if the consumer feels that the new technology is a viable substitute and will pay back in the form of reduced bills over an acceptable period of time, the consumer will adopt, accept, or undertake it.

EE measures include efficient lighting, weatherization, efficient pumps and motors, efficient HVAC infrastructure, and efficient appliances. Often, multiple measures are bundled into a single program that might be offered to either residential or commercial/industrial customers in order to deliver these products in a cost-effective manner.

EE measures will, in all cases, reduce the amount of energy consumed, but some measures may have limited effectiveness at the time of peak demand. EE is viewed as a readily deployable, relatively low cost, and clean energy resource that provides many benefits. According to a March 2007 DOE study such benefits include:

Economics	Reduced energy intensity provides competitive advantage and frees economic resources for investment in non-energy goods and services
Environment	Saving energy reduces air pollution, the degradation of natural resources, risks to public health and global climate change
Infrastructure	Lower demand lessens constraints and congestion on the electric transmission and distribution systems
Security	EE can lessen our vulnerability to events that cut off energy supplies

Unlike supply-side resources, demand-side resources, particularly EE resources, require consumers achieve reduced consumption. While an analysis may indicate that an "investment" in a particular measure is cost-effective, it does not guarantee that conservation will be universally achieved or adopted as technology adoption can be dependent upon many other factors as well, including ease of adoption, market delivery methods, market barriers, and customer economics.

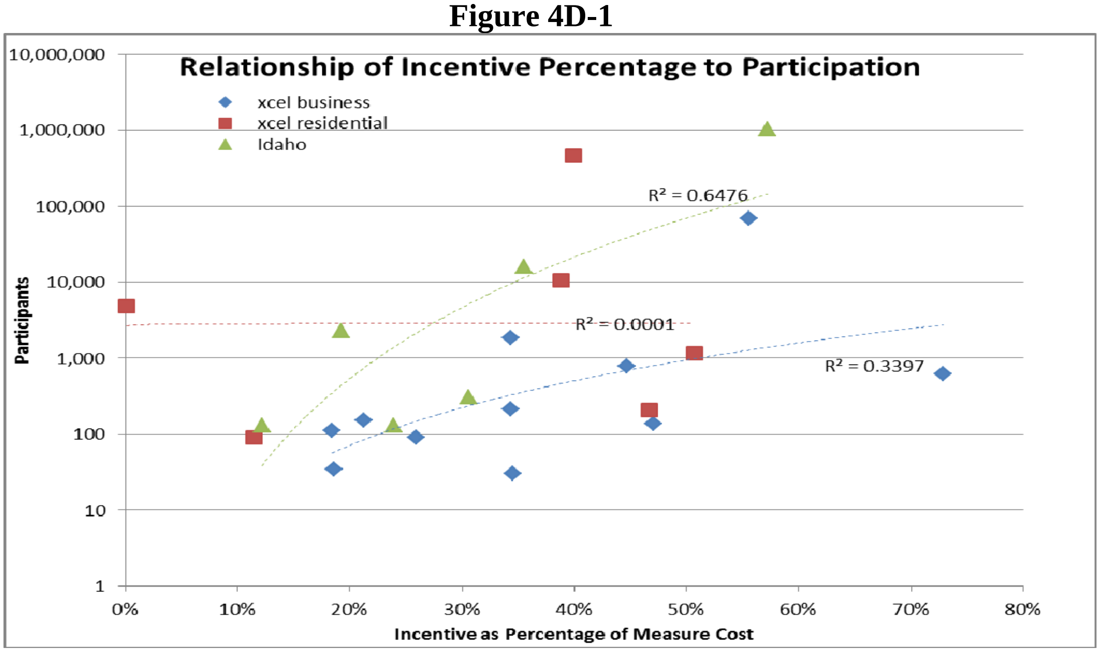
Market barriers to EE exist which limit the rate and ultimate level at which efficiency measures are adopted by consumers (program participants). These typically include: high initial cost, uncertainty about performance, and "agency" problems, where the person buying an appliance may not benefit from the improved efficiency.

To overcome many of the participant barriers noted above, a portfolio of programs may often include several of the following elements:

- Consumer education
- Technical training
- Energy audits
- Rebates and discounts for efficient appliances, equipment and buildings
- Industrial process improvements

The level of incentives (rebates or discounts) offered to participants is a major determinant in the pace of market transformation and measure adoption. To achieve rapid adoption of efficiency measures, it is reasonable to expect increased program costs associated with higher consumer incentives, higher administrative costs and marketing. However, this relationship is not as strong (**Figure. 4D-1**) as the prior relationship of measure cost to participation, as shown by the same data.

Figure 4D-1



Thus, it is safe to say that the over-riding factor affecting participation and "first year" program savings/achievement is the availability of inexpensive energy saving measures. Until the next breakthrough in this area emerges, it is unrealistic to expect program achievement that aligns with mandates conceived during a period where relatively inexpensive (lighting, primarily) programs were responsible for the bulk of the savings.

2. Smart Meters

"Smart meters" are meters that receive and transmit information about energy consumption that is available not only to the utility, but also the consumer. Enhanced information, such as rates that vary with the time of day is enabled with a smart meter. The promise of a smart meter is with the information in the hands of the individual customers; they are better positioned to make decisions to reduce consumption at time of peak.

In 2009, I&M undertook the Smart Meter Pilot Program (SMPP); a unique limited scope test program where I&M customers did not pay for the Pilot deployment. Yet, even with an extensive advertising campaign only 2.2% of customers who had access to the SMPP programs bothered to participate despite clear financial incentives designed to elicit their participation. The SMPP and previous experience from the standard time of day tariff suggests voluntary customer participation rates in excess of 10% will be very difficult to achieve. <u>Substantially greater customer interest will be necessary in order to justify the cost of this or similar future programs.</u>

3. Demand Response

Peak demand, measured in megawatts (MW), can be thought of as the amount of power used at the time of maximum power usage. In the PJM zone, this maximum (System peak) is likely to occur on the hottest summer weekday of the year, in the late afternoon. This happens as a result of the near-simultaneous use of air conditioning by the majority of customers, as well as the normal use of other appliances and (industrial) machinery. At all other times during the day, and throughout the year, the use of power is less.

As peak demand grows with the economy and population, new capacity must ultimately be built. To defer construction of new power plants, the amount of power consumed at the peak must be reduced. In addition to "passive" or "non-dispatchable" resources like EE and EECO, "active" or "dispatchable" resources, which have impacts primarily only at times of peak demand, include:

- *Interruptible loads*. This refers to a contractual agreement between the utility and a large consumer of power, typically an industrial customer. In return for reduced energy costs, an industrial customer agrees to "interrupt" or reduce power consumption during peak periods, freeing up that capacity for use by other consumers.

- *Direct load control*. Very much like an (industrial) interruptible load, but accomplished with many more, smaller, individual loads. Commercial and residential customers, in exchange for monthly credits or payments, allow the energy manager to deactivate or cycle discrete appliances, typically air conditioners, hot water heaters, lighting banks, or pool pumps during periods of peak demand. These power interruptions can be accomplished through various media such as FM-radio signals that activate switches, or through a digital “smart” meter that allows activation of thermostats and other control devices.

- *Time-differentiated rates*. Offers customers different rates for power at different times during the year and even the day. During periods of peak demand, power would be relatively more expensive, encouraging conservation. Rates can be split into as few as two rates (peak and off-peak) and to as often as 15-minute increments known as “real-time pricing.” Accomplishing real-time pricing would typically require digital (smart) metering to “download” pricing signals from a utility host system.

I&M has a Residential Peak Reduction program with over 6,000 participants and interruptible contracts with larger customers amounting to 200 MW of realized capacity reductions coincident with PJM’s peak. Additional peak demand reduction capability has been accomplished with the introduction of tariff-based DR offerings for C&I customers totaling 58 MW.

Expanding DR options beyond interruptible industrial contracts and C&I DR offerings is likely necessary to achieve increased peak demand reductions. I&M continues to explore ways to increase participation in its interruptible and DR programs. On a broad scale, direct load control-type programs are typically more expensive as similar infrastructure is needed to achieve smaller load reductions. Moreover, these programs can also introduce consumer dissatisfaction since the “economic choice” is removed from the customer.

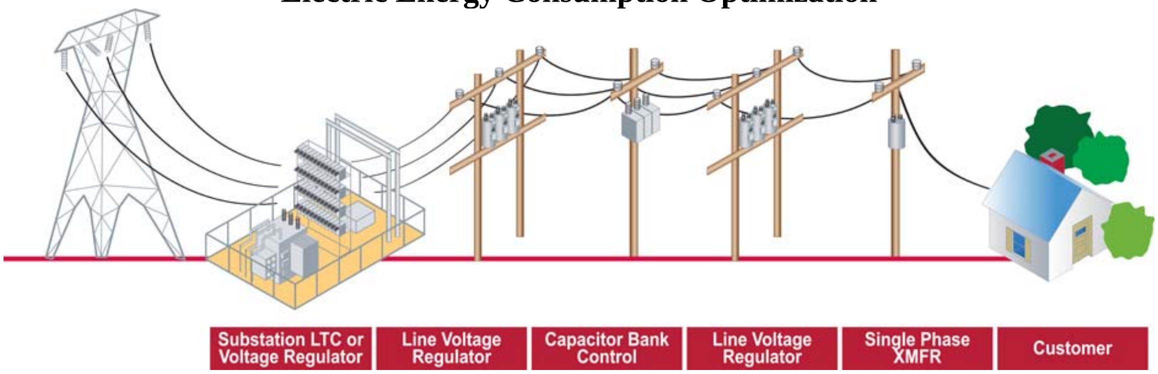
This IRP assumes a continuation of the demand response levels associated with current contracts and tariffs. Other options, including expanded residential DR may also be considered in the future.

4. Electric Energy Consumption Optimization (EECO)

EECO is a smart grid technology that falls under the gridSMART® umbrella of programs. EECO provides all of the benefits of power factor correction, voltage optimization, and condition-based maintenance in a single, optimized package. In addition, EECO enables conservation voltage reduction (CVR) on a utility's system. CVR is a process by which the utility systematically reduces voltages in its distribution network, resulting in a proportional reduction of load on the network. A 1% reduction in voltage typically results in a 1.0% reduction in load.

As the electric infrastructure was built out in the last century, distribution systems were designed to ensure end-users received voltages ranging from 114 to 126 volts in accordance with national standards. Most utility systems were designed so that customers close to the substation received voltages close to 126 volts and customers farther from the substation received lower voltages. This design kept line construction costs low because voltage regulating equipment was only applied when necessary to ensure the required minimum voltages were provided. However, since most devices operated by electricity, especially motors, are designed to operate most efficiently at 115 volts, any "excess" voltage is typically wasted, usually in the form of heat. Tighter voltage regulation, enabled by smart-grid infrastructure, allows end-use devices to operate more efficiently without any action on the part of consumers (**Figure 4D-2**). Consumers will simply use less energy to accomplish the same tasks.

Figure 4D-2
Electric Energy Consumption Optimization



5. Distributed Generation (DG)

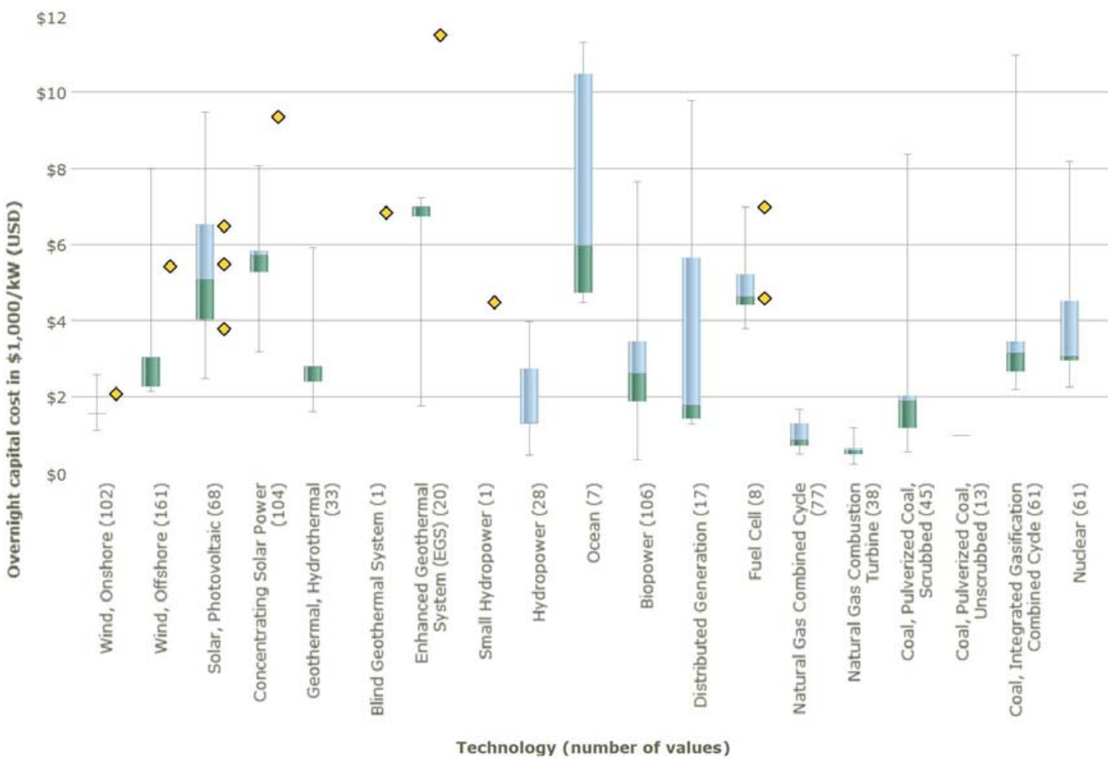
DG can take multiple forms from rooftop (or pole-mounted) solar photovoltaic (PV) panels to combined heat and power (CHP), fuel cells, micro-turbines, diesel internal combustion engines, and small wind turbines. From the perspective of the utility, these different technologies are the same in that they result in a reduction to the load forecast, are owned by the customer, and cost a prescribed amount: either the retail net metering or PURPA rates. Operating characteristics are different and so corresponding the "resource value" to the utility will vary.

6. Technologies Considered But Not Evaluated

Some DG alternatives include: microturbines, fuel cells, CHP, and residential and small commercial wind were not specifically evaluated. However, distributed generation was modeled as a resource that cost either the (full retail) net metering rate or the PURPA rate as appropriate.

Currently, these technologies cost more than other options and were not considered for wide-scale utility implementation. Their costs will continue to be monitored. **Figure 4D-3** shows the significant variation in capital costs for DG and where the costs are relative to other generating technologies[7].

Figure 4D-3
Distributed Generation Capital Costs



E. Assessment of Demand Side Resources

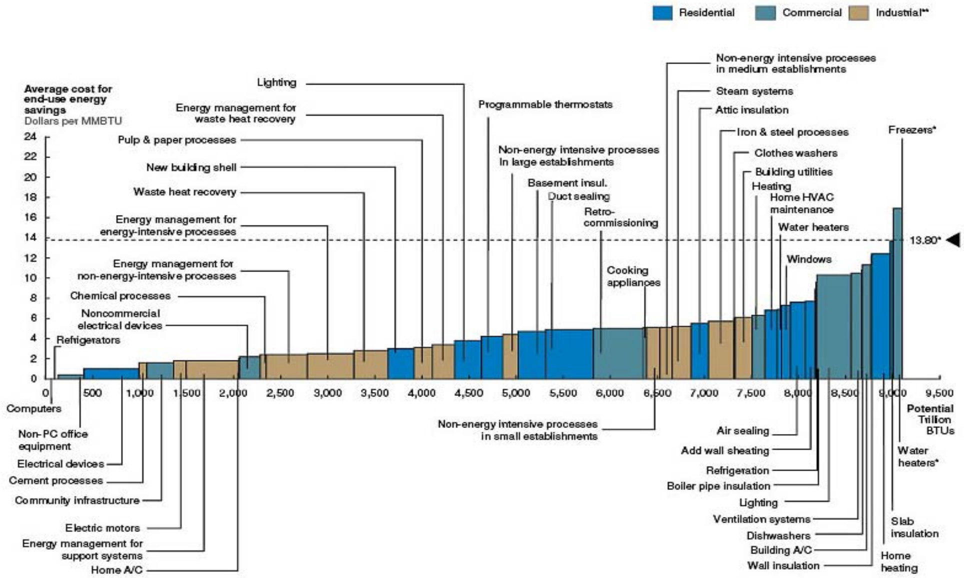
1. Energy Efficiency

While EE measures have a wide range of costs and thus have a "supply curve" similar to other assets, as depicted in **Figure 4E-1**, it is not practically true that the cheapest options will be exhausted first and ahead of more expensive options. Typically, a utility-sponsored program will be required to provide a portfolio of efficiency measures

[7] http://www.nrel.gov/analysis/tech_cost_dg.html

and programs which encompass a range along the cost curve.

Figure 4E-1
EE Supply Curve



* Average price of avoided energy consumption at the industrial price; $35.60/MMBTU represents the highest regional electricity price used; new build cost based on AEO 2008 future construction costs
** Our 49th source of savings, refining processes, offers no NPV-positive savings
Source: EIA AEO 2008, McKinsey analysis

However, the cost that becomes part of the revenue requirement is the program costs, which includes the amount of incentive paid to customers to induce participation as well as program administrative and marketing costs. To evaluate a comprehensive portfolio of measures necessary to achieve large energy reductions, I&M used data from Efficiency Vermont.[8] Efficiency Vermont provides detailed, "by measure" break outs of costs and impacts of well-established programs. The data were adjusted to account for the difference in climate (See **Table 4E-1**).

These resource options were made available after 2019 for optimized portfolios.

[8] See http://www.efficiencyvermont.com/about_us/information_reports/annual_reports.aspx

In addition, to validate the energy efficiency resources that are included in the load forecast, a scenario was run that made EE resources available beginning in 2014 relative to a load forecast that assumed no energy efficiency resources. Running an optimization in this way picks energy efficiency resources including EECO. Again, implicit in the load forecast is an assumption of efficiency resources in this period.

Table 4E-1

		Tier 1	Tier 2
Measure Family	Measure Life (years)	Measure Cost ($/first year MWh)	
Residential Cooling	16	$ 788	$ 788
Residential Heating	24	$ 743	$ 2,074
Residential Lighting	7	$ 264	$ 453
Residential Other	9	$ 500	$ 500
Commercial Cooling	16	$ 184	$ 359
Commercial Heating	24	$ 861	$ 1,187
Commercial Other (lighting)	10	$ 1,124	$ 1,124
Industrial	13	$ 158	$ 710

2. Demand Response

I&M's demand response capability is currently 6% of its peak demand, or approximately 10% of the combined C&I peak demand. Additional resources were not modeled, as this level of resources is considered to be near a practical limit. However, as outlined in Section G of this chapter, multiple tariffs are available for (primarily) commercial customers to enroll directly with I&M for PJM demand-response programs. As customers enroll, I&M will adjust this assumption.

3. EECO

Similar to EE, I&M evaluated EECO as an option prior to 2019 to help satisfy Energy Efficiency benchmarks. The model did select EECO as a resource, validating its cost-effectiveness in the time period. I&M expects to use EECO as an energy efficiency resource.

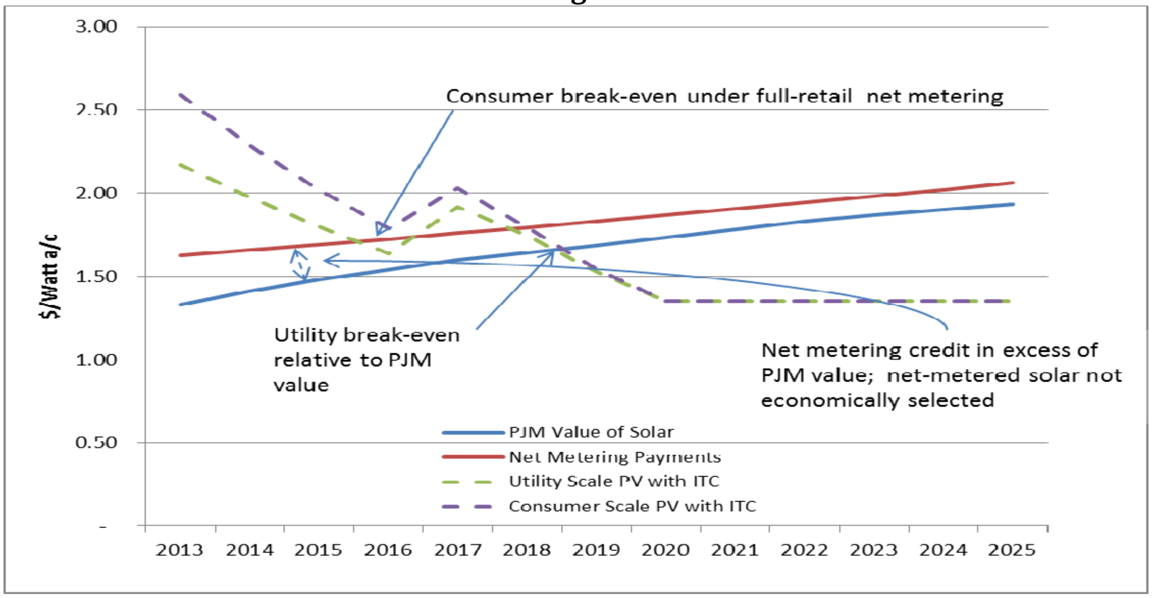
4. Smart Meters

Given the results of the 2009 smart meter pilot, incremental rollouts are not anticipated during the action period. However, residents who chose to participate in the load control feature can continue to participate. Residential (and Commercial) direct load control is a viable way to affect peak demand reductions, but it is not typically as economical as commercial load reductions.

5. Distributed Generation

Distributed generation resources were evaluated using a solar PV resource, as this is likely the primary distributed resource. Solar also has favorable characteristics in that it produces the majority of its energy at times when power prices in PJM are their highest. Costs were the full net metering rate, which is the credit required by regulation. In spite of relatively low current retail rates, customer-sited distributed generation costs the utility more than the PJM value it provides. **Figure 4E-3** shows the dynamic in effect.

Figure 4E-3



6. Discussion and Conclusion

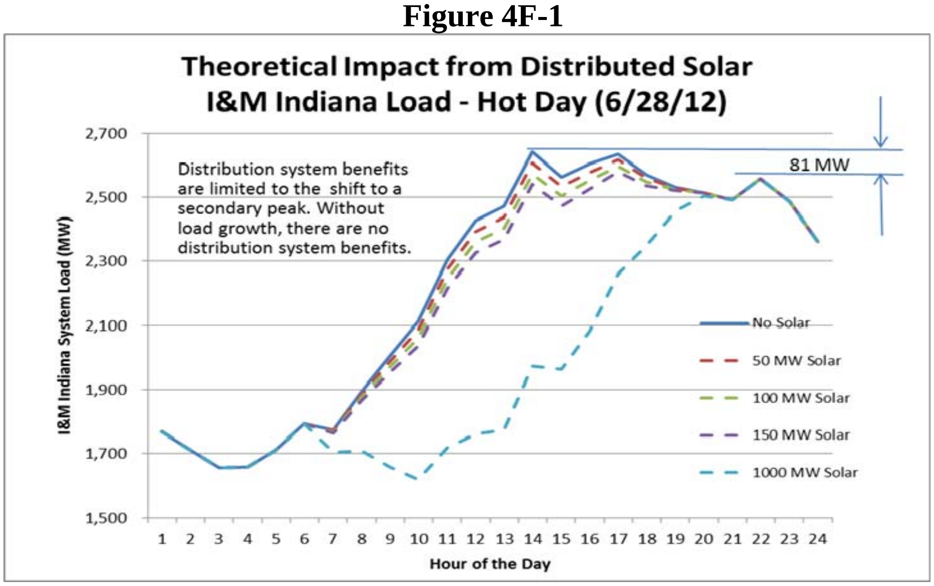
As a result of the requirements of the Indiana DSM Phase II order, an aggressive ramp up of energy efficiency programs remains underway. The composition of the portfolio of programs is decided in an open, collaborative process. A summary of the current portfolio composition is included in **Exhibit 8-9**. Payments to customer-sited generators are currently insufficient to foster much adoption but they also currently exceed the resource's value in PJM. In the near future, net metering credits may be sufficient, given expected cost-reduction in installed solar costs, to spur customer adoption, although those net-metering payments will continue to exceed the value within I&M.

F. DSM and Distributed Generation: Distribution and Transmission Applications

While net metering credits outpace the PJM value of distributed solar, an argument exists that distributed solar's value to the grid is overlooked. In the case of

I&M, this part of solar's value is largely absent for a couple of reasons. First, and foremost, I&M's load is flat-to-negative (see Chapter 3 for a detailed discussion) which practically means that I&M's distribution system is already sized for a load that is higher than its expected load. Similarly, the regional growth is very muted, and I&M, as a result, only has one expansion-related transmission project in PJM's planning queue. The second consideration when determining whether or not any distribution or transmission benefits will result from distributed generation in one's service territory is the nature of the peak demand on the system. Because I&M's peak occurs late in the day in summer and trails off slowly, not abruptly, solar resources will initially reduce peak requirements to the point that a secondary peak develops after the sun goes down (see **Figure 4F-1**). Thus, in a growing service territory, distributed solar resource can effect initial peak reductions, but quickly lose their incremental ability to do so.

Figure 4F-1



G. Current Interruptible Service Rate Options

A contributor to the Company's demand-side management programs currently impacting the IRP is the set of interruptible and curtailment tariffs, riders and special contract agreements. These programs are currently offered to qualifying commercial and industrial customers along with, in some cases, certain market buy-through privileges.

I&M's interruptible service options provide industrial and commercial customers discounts in exchange for their agreement to temporarily curtail their service when requested. I&M's interruptible service options include a Contract Service - Interruptible Power tariff and demand response riders filed by the Company and approved by the IURC relating to emergency and economic interruptions. I&M also has an interruptible customer under a special contract arrangement.

In compliance with the Commission's Order in Cause No. 43566 dated July 28, 2010, the Company began offering several demand response riders in Indiana providing customers additional opportunities to receive compensation in exchange for curtailing demand and energy. These demand response riders are modeled after the PJM demand response programs where customers are only enrolled through the Company. The demand response riders include: Emergency Demand Response (D.R.S. 1), Economic Demand Response (D.R.S. 2) and Ancillary Service Demand Response (D.R.S. 3).

For the 2014 forecast year, and annually thereafter, it is anticipated there will be three interruptible customers with contracted interruptible capacity of approximately 305 MW. Based on historical load patterns and the particular nature of each interruptible contract, the estimated available interruptible load for purposes of this resource planning process is 200 MW (summer rating) for I&M. In addition to these interruptible customers, the Company has 68 demand response (95.6 MW) and 6,067 Residential Peak Reduction Rider customers that may be interrupted under certain conditions, with these customers having 5.5 MW of total demand reduction capacity.

H. Current Time-Of-Use Service Options

Another contributor to I&M's demand-side management programs include optional time-of-use tariffs and demand forgiveness provisions.

Some of I&M's tariffs contain features that are designed to encourage customers to shift load from the on-peak period to the off-peak period. Customers participating in these tariffs are rewarded for shifting load from the on-peak period to the off-peak period and generally benefit from lower off-peak rates for energy and demand shifted to the off-peak period. Encouraging customers to shift their energy consumption to off-peak periods creates a "win-win" situation for I&M and its customers. Participating customers have an opportunity to receive reduced energy costs and I&M has the potential to reduce costs and realize efficiency gains in producing electricity.

I&M offers its customers an opportunity to reduce energy costs through standard and experimental time-of-day (TOD) tariffs, storage water heater, load management time-of-day and off-peak forgiveness tariff provisions. The standard TOD tariffs are available to all customer classes and provide on-peak and off-peak energy charges that are uniformly applicable all year, depending on the day of the week. The experimental TOD tariffs are available to those customers located within the former South Bend Smart Meter Pilot Program (SMPP) area and a limited number of customers outside of the SMPP area and provide on-peak and off-peak energy charges that vary depending on the month of the year. The load management TOD provisions are available to customers who use energy-storage devices with time-differentiated load characteristics (generally equipment operating only during the off-peak hours). The off-peak forgiveness provision disregards, for billing purposes, demand created during the off-peak hours up to certain tariff limitations. Over 3,000 Indiana customers are presently served on TOD tariffs, and approximately 14,300 Indiana residential customers have installed off-peak water heater systems.

The rates associated with time-of-use are designed to reflect the different costs the Company incurs in providing electricity during peak periods when electricity demand is high and off-peak periods when electricity demand is low. I&M’s standard on-peak period is defined as 7 A.M. to 9 P.M., Monday through Friday with the off-peak period being all other hours not defined during the on-peak period. I&M’s experimental on-peak period is defined as 2 P.M. to 6 P.M. May through September with the off-peak period being all other hours not defined during the on-peak period, including all hours during the months of October through April.

Whether customers benefit from time-of-use rates is contingent upon the percentage of total consumption used during on-peak periods, or rather, how much usage is shifted from the on-peak period to the off-peak period.

Listing of I&M’s Time-Of-Use, Interruptible and Demand Response Tariffs

As mentioned above, I&M provides tariffs that encourage customers to make energy-efficient and cost saving decisions by participating in time-of-use and interruptible load programs.

A description of these time-of-use and interruptible service options are shown below in **Table 4H-1**.

Table 4H-1 Time-Of-Use, Interruptible and Demand Response Tariffs-Indiana and Michigan

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
RS-TOD	Time-Of-Use	Available to single-phase residential customers. This tariff provides standard on-peak and off-peak energy charges. Limited to first 2,500 customers (Indiana).	Indiana, Michigan	5,403
RS-TOD2	Time-Of-Use	Experimental program available to single-phase residential customers located within the former South Bend Smart Meter Pilot Program (SMPP) area and a limited number of customers outside of the SMPP. This tariff provides experimental on-peak and off-peak energy charges.	Indiana, Michigan	136
RS-OPES (RS-OPES/PEV in Michigan)	Time-Of-Use	Available to customers eligible for Tariff RS (Residential Service) who use approved energy storage devices with time-differentiated load characteristics, such as electric thermal storage space heating equipment and water heaters that consume electrical energy only during standard off-peak hours and store it for use during standard on-peak hours.	Indiana, Michigan	1,260

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
RS-LMWH/SWH	Time-Of-Use	Provision available for residential customers who install a company-approved load management water heating system with capacity of at least 80 gallons, which consumes electrical energy primarily during off-peak hours specified by the Company and stores hot water for use during on-peak. The last 250 kWh of use in any month shall be billed at an off-peak energy charge. The storage water heating provision is withdrawn except for the present installations of current customers receiving service at premises served prior to May 1, 1997.	Indiana, Michigan	15,217
Rider R.P.R.	Interruptible	Available on a voluntary basis for customers receiving residential electric service. To participate, customers must allow the Company to install load control equipment and, if necessary, auxiliary communicating devices to control the customer's central electric cooling unit(s). The Company will utilize the installed control devices to reduce customer's energy use during load management events.	Indiana	6,067

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
GS-LMTOD (SGS & MGS LM-TOD in Michigan)	Time-Of-Use	Available to customers who use approved energy-storage devices with time-differentiated load characteristics, such as electrical thermal storage space-heating and/or cooling systems and water heaters that consume electrical energy only during Company-specified standard off-peak hours and store energy for use during standard on-peak hours. This tariff provides on-peak and off-peak energy charges.	Indiana, Michigan	147
GS-TOD2 (SGS-TOD2 in Michigan)	Time-Of-Use	Experimental program available to single-phase customers with demands less than 10 kW located within the former South Bend Smart Meter Pilot Program (SMPP) area and a limited number outside the SMPP. This tariff provides on-peak and off-peak energy charges.	Indiana	3
GS-TOD (MGS-TOD in Michigan)	Time-Of-Use	Available to a limited number of general service customers with demands of 150 kW or less These tariffs provide on-peak and off-peak energy charges.	Indiana, Michigan	1,662
LGS-TOD	Time-Of-Use	Available to a limit number of general service customers with demands less than 1,000 kW. This tariff provides on-peak and off-peak energy charges.	Indiana	16

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
LGS-LM-TOD	Time-Of-Use	Available to customers who use approved energy-storage devices with time-differentiated load characteristics, such as electrical thermal storage space-heating and/or cooling systems and water heaters which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours. These tariffs provide on-peak and off-peak energy charges.	Indiana, Michigan	24
LGS OPHP (Off-Peak Hour Provision)	Time-Of-Use	Available for general service customers with maximum demands greater than 60 kVA but less than 1,000 kVA (Indiana) and greater than 100 but less than 1,500 kW (Michigan). Demand created during the off-peak hours is disregarded for billing purposes provided that the billing demand is not less than 60 percent of the maximum demand created during the billing month nor less than 60 percent of either (a) the contract capacity, (b) the customer's highest previously established monthly billing demand during the past 11 months, or (c) 100 kVA.	Indiana, Michigan	1,847
LP OPHP (Off-Peak Hour Provision)	Time-Of-Use	Available for general service customers with contracted capacity of 1,500 kW or greater. Demand created during the off-peak hours is disregarded for billing provided that the billing demand is not less than 60% of the maximum demand created during the billing month, nor less than 1,500 kW nor less than 60% of the contract capacity.	Michigan	24

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
LP (Time-Of-Day Energy Charges)	Time-Of-Use	Available for general service customers with contracted capacity of 1,500 kW or greater under Tariff LP. This tariff provides on-peak and off-peak energy charges.	Michigan	Customers included in the previous LP tariff schedule.
IP OPHP (Off-Peak Hour Provision)	Time-Of-Use	Available for general service customers with normal maximum requirements of 1,000 kVA or greater. Demand created during the off-peak hours is disregarded for billing purposes provided that the billing demand is not less than 60% of the maximum demand created during the billing month nor less than 60% of either (a) the contract capacity or (b) the customer's highest previously established monthly billing demand during the past 11 months.	Indiana	235
WSS (Optional TOD)	Time-Of-Use	Available for the supply of electric energy to waterworks and sewage disposal systems who consume metered usage during off-peak periods. Customers with normal maximum demands of 100 kW or more (Michigan only) have the option to receive this service. This tariff provides on-peak and off-peak energy charges.	Indiana, Michigan	4

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
EHS OPHP (Off-Peak Hour Provision)	Time-Of-Use	Not available for new applications. Available to primary and secondary schools and to college and university buildings where the principal energy requirements (all lighting, heating, cooling, water heating, and cooking) are provided by electric energy. Demand created during the off-peak hours is disregarded for billing purposes provided that the billing demand is not less than 60 percent of the maximum demand created during the billing month. Note: This tariff has been withdrawn except for existing installations.	Michigan	40
CS-IRP2 (CS-IRP in Michigan)	Interruptible	Available to customers with interruptible demands of 1,000 kW/kVA who contract for service under one or both of the Company's interruptible service options, those being emergency and discretionary. The total contract capacity for all customers served under this tariff, Tariff CS-IRP2, and Rider DRS1 is limited to 235,000 kVA in Indiana and 50,000 kW in Michigan.	Indiana, Michigan	7
Special Interruptible Contract	Interruptible	Special Contract provides for curtailment of load.	Indiana	1

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
D.R.S.-1	Interruptible	Available to commercial and industrial customers who have the ability to curtail load under the provisions of this demand response emergency rider and receives a payment each month. The Company will directly enroll customers in the PJM Emergency Demand Response Program.	Indiana	63
D.R.S.-2	Interruptible	Available to commercial and industrial customers who voluntarily respond to locational marginal prices (LMP) by reducing consumption and receive a payment for those reductions. The Company will directly enroll customers in the PJM Economic Demand Response Program.	Indiana	5
D.R.S.-3	Interruptible	Available to commercial and industrial customers who have the opportunity to offer demand response to meet the needs of the transmission system and receive a payment or credit for such demand response. The Company will directly enroll customers in the PJM Economic Demand Response Program.	Indiana	0

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
Utility Residential Weatherization Program (URWP)	Weatherization	Upon customer request, I&M may provide financial assistance in the form of loans to residential customers for the cost of certain energy conservation measures. Qualified homes must use electricity for space heating or air conditioning. After I&M conducts the Residential Conservation Service Program audit, the Company will assist the customer to install energy conservation measures by financing the cost of such conservation measures in amounts up to $1,500 with a maximum repayment period of three years.	Indiana	12

Note 1: I&M-Indiana and I&M-Michigan's standard off-peak billing period is defined as 9 p.m. to 7 am, local time, Monday through Friday including all hours of Saturdays and Sundays. I&M-Indiana's experimental off-peak billing period used in the former South Bend Smart Meter Pilot area is defined as midnight to 2 p.m. and 6 p.m. to midnight May through September and all hours October through April.

Note 2: The Utility Residential Weatherization Program shown in the table above is offered by the Company to its Indiana customers through Terms and Conditions of Service #23.

Note3: The tariff descriptions shown above are in summary form. To obtain a full description, please see the Company's current Indiana and Michigan Tariff Books.

Table 4H-2 below reflects I&M's demand reduction in MW for each off-peak tariff schedule.

Table 4H-2 - Time-Of-Use Demand Reduction

Class	**Coincident Peak Demand Reduction (MW)**
Residential LMWH	3.3
Residential WH80	0.2
Residential WH100	0.2
Residential WH120	2.1
Residential TOD2	0.1
Residential TOD	0.7
Residential OPES	1.0
Residential RPR	6.7
GS TOD	4.6
GS LM-TOD	0.9
GS-TOD2	0.0
SGS LMTOD (MI)	0.0
MGS LM-TOD (MI)	0.0
MGS TOD (MI)	0.4
LGS LM-TOD	0.8
LGS TOD	0.6
LGS Secondary OPHP	0.6
LGS Primary OPHP	1.1
IP Primary OPHP	0.5
IP Secondary OPHP	0.9
IP Subtrans OPHP	0.4
IP Transmission OPHP	1.4
LP Primary OPHP	0.2
LP Secondary OPHP	0.0
LP Subtrans OPHP	0.0
LP Transmission OPHP	0.3
WSS-TOD	0.1
Total	27.1

5) Supply-Side Resources

A. Introduction

Supply-side resources include existing and new utility-scale sources that can supply the electrical energy requirements of I&M's customers. This chapter describes existing capacity and other bulk power arrangements, expected changes to existing capacity, including potential retirements, and the screening of potential new resources.

B. Existing Pool and Bulk Power Arrangements

(170 IAC 4-7-6(a) (5) and 170 IAC 4-7-6(c) (4))

1. Interconnection Agreement

As stated in Section 2.A., on December 17, 2010, in accordance with Section 13.2 of the Pool Agreement, each of the Pool members provided notice to the other members (and to AEPSC), as agent) to terminate the Pool Agreement (which includes the IAA), on January 1, 2014. As a result, effective January 1, 2014, I&M will be responsible for its own generation resources and will need to maintain an adequate level of power supply resources to individually meet its own load requirements for capacity and energy, including any required reserve margin.

2. Transmission Agreement

The AEP System Transmission Agreement, updated and approved by FERC Order on October 29, 2010, provides for the sharing among the members of the AEP System-East Zone, including I&M, of the costs incurred by the members for the ownership, operation, and maintenance of their portions of the high voltage transmission system, in order to enhance equity among the members for the continued development of a reliable and economic high voltage system. Members having high voltage transmission investments greater than their respective load shares receive payments from members with investments less than their respective load shares.

3. PJM Membership

On October 1, 2004, the AEP System-East Zone, including I&M, joined the PJM Interconnection. PJM is a FERC-approved RTO that coordinates the movement of wholesale electricity in all or parts of thirteen states and the District of Columbia. PJM manages a regional planning process for expansion of the transmission system and continuously monitors the transmission grid. PJM operates a competitive wholesale electricity market and dispatches the generating units of its members, based on energy offers made by the members, seeking to provide the lowest possible cost of electricity within its footprint. PJM sets generation planning reserve requirements for its members *(Refer to Chapter 2 section D).*

4. OVEC Purchase Entitlement

Three AEP operating companies (APCo, I&M and OPCo) are among the owners of the Ohio Valley Electric Corporation (OVEC) and its subsidiary Indiana-Kentucky Electric Corporation (IKEC). At this time, I&M's share of the OVEC units' capacity is approximately 18.06%.

C. Existing Units

(170 IAC 4-7-4 (7) and 170 IAC 4-7-6 (a) (1)-(3))

1. Current Supply

Exhibit 5-1 offers a summary of all existing supply resources for I&M as of June 1, 2013. **Figure 5C-1** summarizes the data in Exhibit 5-1 and also includes, for information, the PJM RTO installed capacity (including purchases) by fuel type as of July 1, 2013[9]. Total PJM RTO capacity is 185,539 MW of which 40.4% is coal fired, 34.5% is gas/oil and 18.2% is nuclear. The 2013 summer I&M capacity of 5,495 MW are composed of the following resource types (MW):

Figure 5C-1

2013 Generating Capacity

	I&M		PJM RTO	
Supply Resource Type	MW	% of Total	MW	% of Total
Coal	3,205	58.3%	75,003	40.4%
Nuclear	2,064	37.6%	33,771	18.2%
Natural Gas	0	0.0%	49,830	26.9%
Oil	0	0.0%	14,226	7.7%
Hydro	18	0.3%	7,964	4.3%
Wind	41	0.7%	877	0.5%
Solar	0	0.0%	106	0.1%
Other	0	0.0%	1,757	0.9%
Purchase	167	3.0%	2,005	1.1%
Total	5,495	100.0%	185,539	100.0%

Note: Totals exclude DSM/EE programs values

2. Capability Adjustments

The capability forecast of the existing I&M generating fleet over the 2014-2033 forecast period reflects a reduction of approximately 896 MW as a result of unit reratings associated with environmental facility retrofit, and coal unit retirements, netted against upgrades associated with planned efficiency improvements. This table reflects the Preferred Portfolio.

[9] http://www.pjm.com/~/media/markets-ops/ops-analysis/capacity-by-fuel-type-2013.ashx

Output changes to I&M generating units are shown in **Figure 5C-2** as well as **Exhibit 5-2**.

Figure 5C-2

Year	Unit	Modification	Capacity Change (MW)
2015	Tanners Creek 1	Retirement	(145)
2015	Tanners Creek 2	Retirement	(142)
2015	Tanners Creek 3	Retirement	(195)
2015	Tanners Creek 4	Retirement	(500)
2015	Rockport 1	DSI	0
2015	Rockport 2	DSI	0
2016	Cook 2	Turbine Uprate	50
2017	Rockport 1	Turbine Uprate	36
2019	Rockport 2	Turbine Uprate	36
2026	Rockport 1	FGD Derate	(18)
2029	Rockport 2	FGD Derate	(18)
		Total	(896)

3. Fuel Inventory and Procurement Practices

a. General

The generating units of I&M are expected to have adequate fuel supplies to meet full-load burn requirements in both the short-term and the long-term. AEPSC, acting as agent for I&M, is responsible for the procurement and delivery of coal to I&M's generating stations, as well as setting coal inventory target level ranges and monitoring those levels. AEPSC's primary objective is to assure a continuous supply of quality coal at the lowest cost reasonably possible. Deliveries are arranged so that sufficient coal is available at all times. The consistency and quality of the coal delivered to the generating stations is also vitally important. The consistency of the sulfur content of the delivered coal is fundamental to I&M in achieving and maintaining compliance with the applicable environmental limitations.

b. Units

I&M has two coal-fired generating stations, Rockport and Tanners Creek, both in Indiana. The Rockport Generating Station, located in Spencer County, consists of two 1,300-megawatt coal fired generating units. Sulfur dioxide (SO_2) emissions at Rockport are limited to 1.2 lb. SO_2/MMBtu. Compliance with the emission limit is achieved by using a blend of Powder River Basin low sulfur sub-bituminous coal and low sulfur bituminous coal from Colorado or eastern sources. The Tanners Creek generating station is located in Dearborn County, and consists of four coal-fired units with a total Net Maximum Capacity (NMC) of 995 megawatts. In accordance with the NSR Consent Decree, Tanners Creek Units 1, 2, and 3 (TC 1-3) are limited to fuels with a sulfur content no greater than 1.2 lb. SO_2/MMBtu and Unit 4 (TC-4) is limited to fuels with a sulfur content no greater than 1.2%, with both sulfur content restrictions on the Tanners Creek units being enforced on an annual average basis. As a result of the different air emission standards, as well as differences in the boiler designs, the coal supplies for Tanners Creek 1-3 and Tanners Creek-4 vary in order to match the differing quality requirements of the units. The fuel for Tanners Creek 1-3 will be from bituminous sources located in Colorado and from eastern bituminous sources. Tanners Creek 4, similar to the Rockport Station, can use a blend of Powder River Basin coal from Wyoming and low sulfur bituminous coal from eastern sources.

c. Procurement Process

Coal delivery requirements are determined by taking into account existing coal inventory, forecasted coal consumption, and adjustments for contingencies that necessitate an increase or decrease in coal inventory levels. Sources of coal are established by taking into account contractual obligations and existing sources of supply. I&M's total coal requirements are met using a portfolio of long-term arrangements, and spot-market purchases. Long-term contracts support a relatively stable and consistent supply of coal. When needed, spot purchases are used to provide flexibility in scheduling contract deliveries to accommodate changing demand and to cover shortfalls in deliveries caused by force majeure and other unforeseeable or unexpected circumstances. Occasionally, spot purchases may also be made to test-burn any promising and potential new long-term sources of coal in order to determine their acceptability as a fuel source in a given power plant's generating units.

d. Contract Descriptions

Rockport's need for coal is being supplied primarily through two long-term supply agreements with Peabody COALSALES, LLC.

In addition to these long-term contracts, there are several other committed contracts, both term and spot, that will contribute to fulfilling the supply requirements. Any remaining supply requirements will be fulfilled with non-committed purchases. As these agreements expire, additional coal supplies will be contracted to maintain a sufficient supply of coal.

Contract coal for Tanners Creek 1-3 will be supplied pursuant to the Bowie Resources, LLC Magnum Coal Sales LLC, and the Argus Energy LLC long-term agreements. The primary source of Tanners Creek 4 coal deliveries is the extended

Peabody COALSALES, LLC long-term contract discussed above. In addition to these long-term contracts, non-committed coal will be purchased to maintain sufficient coal supplies.

e. Inventory

I&M attempts to maintain in storage at each plant an adequate coal supply to meet full-load burn requirements. However, in situations where coal supplies fall below prescribed minimum levels, programs have been developed to conserve coal supplies. In the event of a severe coal shortage, I&M would implement procedures for the orderly reduction of the consumption of electricity, in accordance with the Emergency Operating Plan.

f. Forecasted Fuel Prices

I&M specific forecasted annual fuel prices, by unit, for the period 2014 through 2023 are displayed in **Exhibit 1** of the Confidential Supplement.

4. Capacity Acquisitions and Dispositions

As part of its resource planning process, I&M continues to investigate the viability of placing indicative offers on additional utility or IPP-owned natural gas peaking and combined cycle facilities.

Another important initial process within this 2013 IRP cycle was the establishment of a near-term view of disposition alternatives facing older, smaller currently uncontrolled coal-steam units in I&M. Prior "Unit Disposition" analyses identified aging I&M generating assets consisting of a total of 4 units with a PJM (summer) rating of 982 MW. The units include Tanners Creek Units 1-3 (482 MW), and Tanners Creek Units 4 (500 MW).

Among this group of units are those that were impacted by the Consent Decree from the previously settled NSR litigation, which require that AEP retires a total of 600 MW of coal-fired generating units from a portfolio of units that includes TC 1-3. These units, and the dates by which, according to the agreement, they must be retired, repowered (as highly thermally efficient combined cycle units), or retrofitted with FGD and SCR systems (R/R/R), include Tanners Creek 1-3 by December 31, 2018. Regardless, the previously described EPA MATS rule has now forced the retirement of TC 1-3 units by June 2015.

Also, while TC 4 was not specifically called out in the original Decree in terms of disposition alternatives, the (3rd) modified Consent Decree now establishes a date-certain disposition date and/or options for that unit. That unit now must either refuel with natural gas or retire by June 2015.

All units will need to be controlled under the MATS rule by June 2015 (or, potentially, June 2016 should a one-year extension be granted for that purpose). This new rule effectively established a new disposition date for each uncontrolled Tanner's Creek unit.

All units will need to be controlled under the MATS rule by June 2015 (or, potentially, June 2016 should a one-year extension be granted for that purpose). This new rule effectively established a new R/R/R date for each uncontrolled unit, including Tanners Creek 1-4.

5. Projected Capacity Position

Figure 5C-3 shows I&M's "Going-in" PJM capacity position with the specified retirements versus the projected PJM reserve margin requirement. This position reflects I&M's capacity before any potential additions. Based on the assumptions mentioned, the capacity of I&M would move to a deficit position in 2015 and 2016 from the PJM view and capacity long for the remainder of the forecast period.

Figure 5C-3

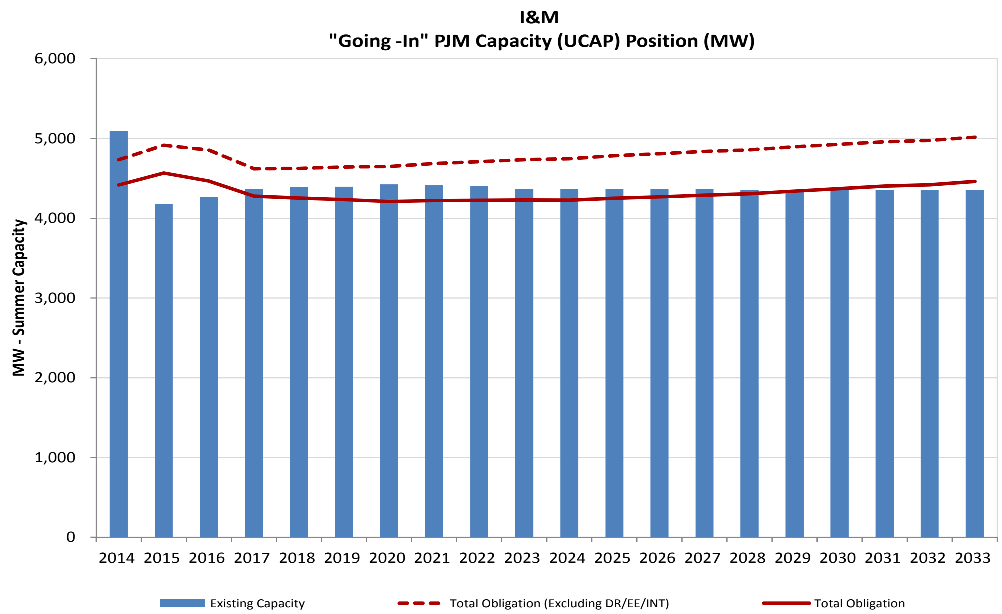


Exhibit 5-3 shows the final position after the analysis. The impact of any new non-contracted market purchases are shown as "Short Term Purchases." The impact of additional Renewable Purchase Power Agreements (REPA) and incremental EE that would be required to minimally achieve mandated renewable energy resources are shown as "New Generation."

D. Supply-Side Resource Screening

(170 IAC 4-7-6(c) (1)-(2) and 170 IAC 4-7-7(a) and 170 IAC 4-7-8(4))

1. Capacity Resource Options

In addition to market capacity purchase options, new-build options were modeled to represent peaking and baseload/intermediate capacity resource options. To reduce the number of modeling permutations in *Plexos*®, the available technology options were limited to certain representative unit types. However, it is important to note that alternative technologies with comparable cost and performance characteristics may ultimately be substituted should technological or market-based profile changes warrant. The options assumed to be available for modeling analyses for I&M are presented in **Exhibit 2** of the Confidential Supplement. When applicable, I&M may take advantage of economical market opportunities in the form of limited-term bilateral capacity purchases and discounted generation asset purchases. Such market opportunities could be utilized to hedge capacity planning exposures should they emerge and create (energy) option value to the Company. Prospectively, these opportunities could take the place of currently planned resources and will be evaluated on a case-by-case basis.

2. Supply-Side Screening

As identified in Exhibit 2 of the Confidential Supplement, base/intermediate and peaking generating technologies were considered in this IRP. However, in an attempt to reduce the problem size within the *Plexos*® modeling application, an economic screening process was used to analyze various options and develop a quantitative comparison for each type of capacity (baseload, intermediate, and peaking) on a forty-year, levelized basis. The options were screened by comparing levelized annual busbar costs over a range of capacity factors.

In this evaluation, each type of technology is represented by a line showing the relationship between its total levelized annual cost per kW and an assumed annual capacity factor. The value at a capacity factor of zero represents the fixed costs, including carrying charges and fixed O&M, which would be incurred even if the unit produced no energy. The slope of the line reflects variable costs, including fuel, emissions, and variable O&M, which increase in proportion to the energy produced.

All peaking technology options, for example, were compared to find the relative economic "best of class" to be used for purposes of further modeling within *Plexos* ®. Screening curves for the peaking capacity types are shown on **Exhibit 5-4**. This chart suggests that the GE 7EA and 7FA turbines are generally more economical than the various aero-derivative machines up to a capacity factor range of 15-20%. Similar screening results are presented for natural gas combined cycle capacity in **Exhibit 5-5.** A comparison of the best-in-class technologies is presented in **Exhibit 5-6**.

The best of class technology determined by this screening process was taken forward to the *Plexos*® model. These generation technologies were intended to represent reasonable proxies for each capacity type (baseload, intermediate, peaking). Subsequent substitution of specific technologies could occur in any ultimate plan, based on emerging economic or non-economic factors not yet identified.

AEP's Generation organization is responsible for the tracking and monitoring of estimated cost and performance parameters for a wide array of generation technologies.

Utilizing access to industry collaboratives such as EPRI and the Edison Electric Institute, AEP's association with architect and engineering firms and original equipment manufacturers as well as its own experience and market intelligence, this group continually monitors supply-side trends. **Table 5D-1** offers a summary of the most recent technology performance parameter data developed.

Table 5D-1
New Generation Technology Options

Key Supply-Side Resource Option Assumptions (a)(b)(c)

Type	Capability (MW) Std. ISO	Trans. Cost (e) ($/kW)	Emission Rates SO2 (g) (Lb/mmBtu)	NOx (Lb/mmBtu)	CO2 (Lb/mmBtu)	Capacity Factor (%)	Overall Availability (%)
Base / Intermediate							
Combined Cycle (1X1 GE7FA.05)	300	60	0.0007	0.009	116.0	60	89.1
Combined Cycle (2X1 GE7FA.05)	624	60	0.0007	0.009	116.0	60	89.1
Combined Cycle (2X1 GE7FA.05, w/ Duct Firing)	624	60	0.0007	0.009	116.0	60	89.1
Combined Cycle (2X1 GE7FA.05, w/ Duct Firing, Inlet Chillers)	624	60	0.0007	0.009	116.0	60	89.1
Combined Cycle (2X1 GE7FA.05, w/ Duct Firing, Blk Start)	624	60	0.0007	0.009	116.0	60	89.1
Combined Cycle (1X1 SGT6-5000, w/ Evap Coolers)	294	60	0.0007	0.010	116.0	60	89.1
Combined Cycle (2X1 SGT6-5000, w/ Evap Coolers)	609	60	0.0007	0.010	116.0	60	89.1
Combined Cycle (2X1 KA24-2, w/ Evap Coolers)	647	60	0.0007	0.011	116.0	60	89.1
Combined Cycle (2X1 M501GAC, w/ Duct Firing, Inlet Chillers)	780	60	0.0007	0.007	116.0	60	89.1
Peaking							
Combustion Turbine (2X1GE7EA)	164	57	0.0007	0.033	116.0	3	93.0
Combustion Turbine (2X1GE7EA,w/ Blk Start)	164	57	0.0007	0.033	116.0	3	93.0
Combustion Turbine (2X1GE7EA, w/ Inlet Chillers)	164	59	0.0007	0.009	116.0	3	93.0
Combustion Turbine (2X1GE7FA.05, w/ Inlet Chillers)	418	59	0.0007	0.007	116.0	3	93.0
Aero-Derivative (1X GE LM6000PF)	45	60	0.0007	0.093	116.0	3	95.0
Aero-Derivative (2X GE LM6000PF)	91	60	0.0007	0.093	116.0	3	95.0
Aero-Derivative (2X GE LM6000PF, w/ Blk Start)	91	60	0.0007	0.093	116.0	3	95.0
Aero-Derivative (1X GE LMS100PB)	98	59	0.0007	0.011	116.0	30	95.0
Aero-Derivative (2X GE LMS100PB, w/ Blk Start)	196	59	0.0007	0.093	116.0	30	95.0
Aero-Derivative (2X GE LMS100PB, w/ Inlet Chillers)	196	59	0.0007	0.007	116.0	25	95.0
Wartsila 22 X 20V34SG	201	60	0.0007	0.018	116.0	3	94.0

Notes:
(a) Installed cost, capability and heat rate numbers have been rounded.
(b) All costs in 2012 dollars. Assume 1.6% escalation rate for 2012 and beyond.
(c) $/kW costs are based on Standard ISO capability.
(e) Transmission Cost ($/kW,w/AFUDC).
(g) Based on 4.5 lb. Coal.

3. Baseload/Intermediate Alternatives

Coal and Nuclear baseload options were not included in this plan. For coal, the proposed EPA New Source Performance Standards (NSPS) rulemaking[10] effectively makes the construction of new coal plants environmentally/economically impractical due

[10] On March 27, 2012, the US EPA issued proposed NSPS for GHG emissions from new power plants pursuant to section 111 of the Clean Air Act (CAA)

to the implicit requirement of carbon capture and sequestration (CCS) technology. For new nuclear construction, it is financially impractical since it requires (minimally) $6,000/kW investment cost. However, the Cook Nuclear Plant uprate of 200MW per unit was made available for the model to select.

Intermediate generating sources are typically expected to serve a load-following and cycling duty and shield baseload units from that obligation. Historically, many generators, such as AEP's eastern fleet, have relied on older, smaller, less-efficient/higher dispatch cost, subcritical coal-fired units to serve such load-following roles. Over the last several years, these units' staffs have made strides to improve ramp rates, regulation capability, and reduce downturn (minimum load capabilities). As the fleet continues to age and subcritical units are retired, other generation dispatch alternatives and new generation will need to be considered to cost effectively meet this duty cycle's operating characteristics.

a. Natural Gas Combined Cycle (NGCC)

An NGCC plant combines a steam cycle and a combustion gas turbine cycle to produce power. Waste heat (~1,100°F) from one or more combustion turbines passes through a heat recovery steam generator (HRSG) producing steam. The steam drives a steam turbine generator which produces about one-third of the NGCC plant power, depending upon the gas-to-steam turbine design "platform," while the combustion turbines produce the other two-thirds.

The main features of the NGCC plant are high reliability, reasonable capital costs, operating efficiency (at 45-60% Low Heating Value), low emission levels, small footprint and shorter construction periods than coal-based plants. In the past 8 to 10 years, NGCC plants were often selected to meet new intermediate and certain baseload needs. NGCC plants may be designed with the capability of being "islanded" which would allow them, in concert with an associated diesel generator, to perform system restoration ("black start") services. Although cycling duty is typically not a concern, an issue faced by NGCC when load-following is the erosion of efficiency due to an inability to maintain optimum air-to-fuel pressure and turbine exhaust and steam temperatures. Methods to address these include:

- Installation of advanced automated controls.
- Supplemental firing while at full load with a reduction in firing when load decreases. When supplemental firing reaches zero, fuel to the gas turbine is cutback. This approach would reduce efficiency at full load, but would likewise greatly reduce efficiency degradation in lower-load ranges.
- Use of multiple gas turbines coupled with a waste heat boiler that will give the widest load range with minimum efficiency penalty.

4. Peaking Alternatives

Peaking generating sources provide needed capacity during extreme high-use peaking periods and/or periods in which significant shifts in the load (or supply) curve dictate the need for "quick-response" capability. The peaks occur for only a few hours each year and the installed reserve requirement is predicated on a one day in ten year loss of load expectation, so the capacity dedicated to serving this reliability function can be expected to provide very little energy over an annual load cycle. As a result, fuel efficiency and other variable costs are of less concern. This capacity should be obtained at the lowest practical installed cost, despite the fact that such capacity often has very high energy costs. This peaking requirement is manifested in the system load duration curve.

In addition, in certain situations, peaking capacity such as combustion turbines can provide backup and some have the ability to provide emergency (Black Start) capability to the grid.

a. Simple Cycle Combustion Turbines (NGCT)

In “industrial” or “frame-type” combustion turbine systems, air compressed by an axial compressor (front section) is mixed with fuel and burned in a combustion chamber (middle section). The resulting hot gas then expands and cools while passing through a turbine (rear section). The rotating rear turbine not only runs the axial compressor in the front section but also provides rotating shaft power to drive an electric generator. The exhaust from a combustion turbine can range in temperature between 800 and 1,150 degrees Fahrenheit and contains substantial thermal energy. A simple cycle combustion turbine system is one in which the exhaust from the gas turbine is vented to the atmosphere and its energy lost, i.e., not recovered as in a combined cycle design. While not as efficient (at 30-35% LHV), they are inexpensive to purchase, compact, and simple to operate.

b. Aeroderivatives (AD)

Aeroderivatives are aircraft jet engines used in ground installations for power generation. They are smaller in size, lighter weight, and can start and stop quicker than their larger industrial or "frame" counterparts. For example, the GE 7EA frame machine requires 20 minutes to ramp up to full load while the smaller LM6000 aeroderivative only needs 10 minutes from start to full load. However, the cost per kW of an aeroderivative is on the order of 20% higher than a frame machine.

The AD performance operating characteristics of rapid startup and shutdown make the aeroderivatives well suited to peaking generation needs. The aeroderivatives can operate at full load for a small percentage of the time allowing for multiple daily startups to meet peak demands, compared to frame machines which are more commonly expected to start up once per day and operate at continuous full load for 10 to 16 hours per day. The cycling capabilities provide aeroderivatives the ability to backup variable renewables such as solar and wind. This operating characteristic is expected to become more valuable over time as: a) the penetration of variable renewables increase; b) baseload generation processes become more complex limiting their ability to load follow and; c) intermediate coal-fueled generating units are retired from commercial service.

Aeroderivatives weigh less than their industrial counterparts allowing for skid or modular installations. Efficiency is also a consideration in choosing an aeroderivative over an industrial turbine. Aeroderivatives in the less than 100 MW range are more efficient and have lower heat rates in simple cycle operation than industrial units of equivalent size. Exhaust gas temperatures are lower in the aeroderivative units.

Some of the better known aeroderivative vendors and their models include GE's LM series, Pratt & Whitney's FT8 packages, and the Rolls Royce Trent and Avon series of machines.[11]

5. Renewable Alternatives

Renewable generation alternatives use energy sources that are either naturally occurring (wind, solar, hydro or geothermal), or are sourced from a by-product or waste-product of another process (biomass or landfill gas). In the recent past, development of these resources has been driven primarily as the result of renewable portfolio requirements. That is not universally true now as advancements in both solar PV and wind turbine manufacturing have brought costs down.

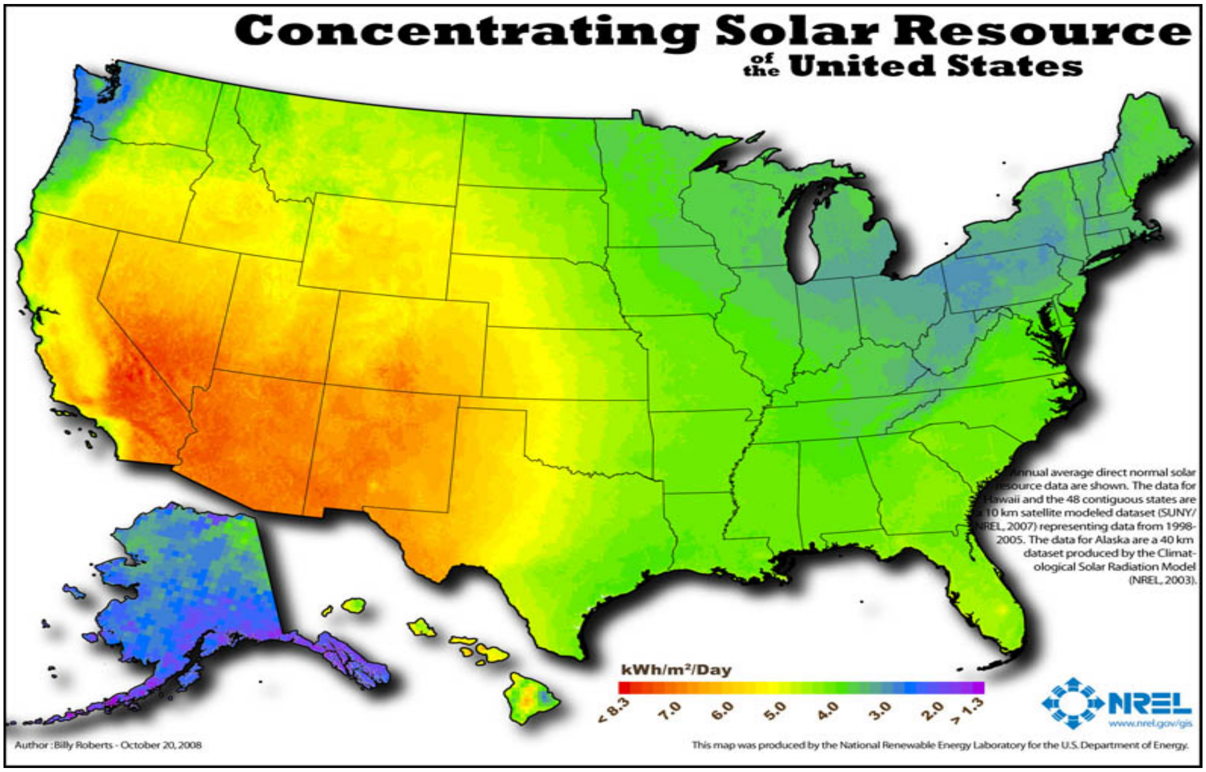
Because wind resources are not always productive during the time of system peak, these resources are assumed to have "useful capacity" equivalent to 13% of their nameplate capacity within PJM.

a. Utility Scale Solar

Solar power takes a couple of viable forms to produce electricity: concentrating and photovoltaics. Concentrating solar – which heats a working fluid to temperatures sufficient to power a turbine - produces electricity on a large scale and is similar to traditional centralized supply assets in that way. Photovoltaics produce electricity on a smaller scale (2 kW to 20 MW per installation) and can be distributed throughout the grid. **Figure 5D-2** shows the potential solar resource locations in the U.S.

[11] Turbomachinery International, Jan/Feb. 2009; Gas Turbine World; EPRI TAG

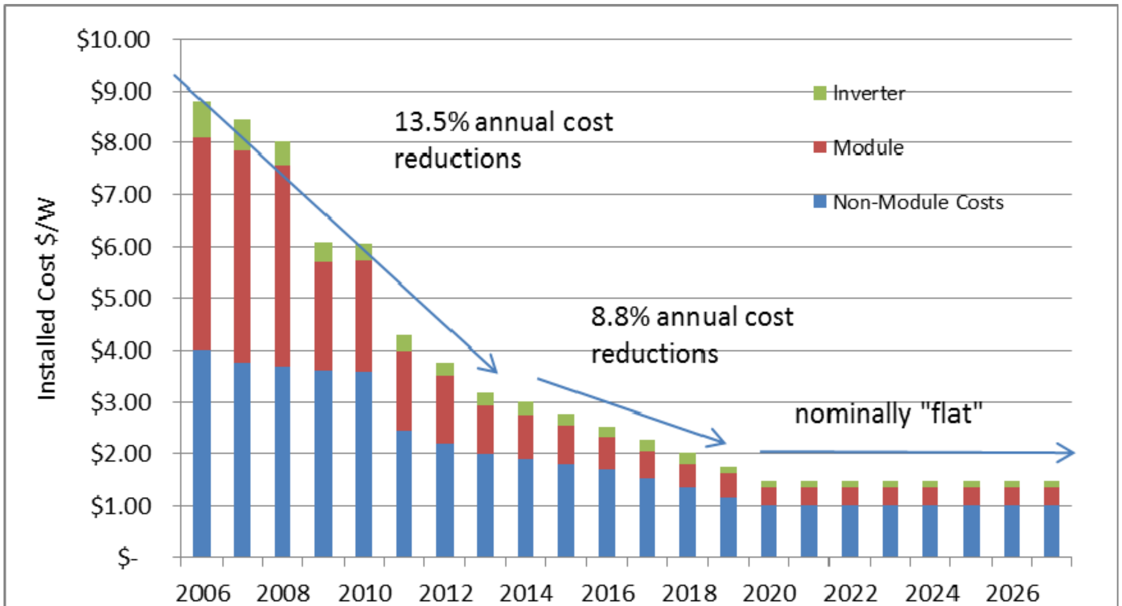
Figure 5D-2
United States Solar Power Locations



The cost of solar panels has declined considerably in the past decade. This has been mostly a result of reduced panel prices that have resulted from manufacturing efficiencies spurred by accelerating penetration of solar energy in Europe, Japan, and California. With the trend firmly established, forecasts generally foresee declining nominal prices in the next decade as well.

Not only are utility scale solar plants getting less expensive, the costs to install solar panels in distributed locations, often on a rooftop, are lessening as associated hardware, such as inverters, racks, and wiring bundles become standardized (See **Figure 5D-3**). If the projected cost declines materialize, both distributed and utility scale solar projects will be economically justifiable in the future.

Figure 5D-3
Solar Panel Installed Cost



Source: Navigant Consulting and AEP Resource Planning

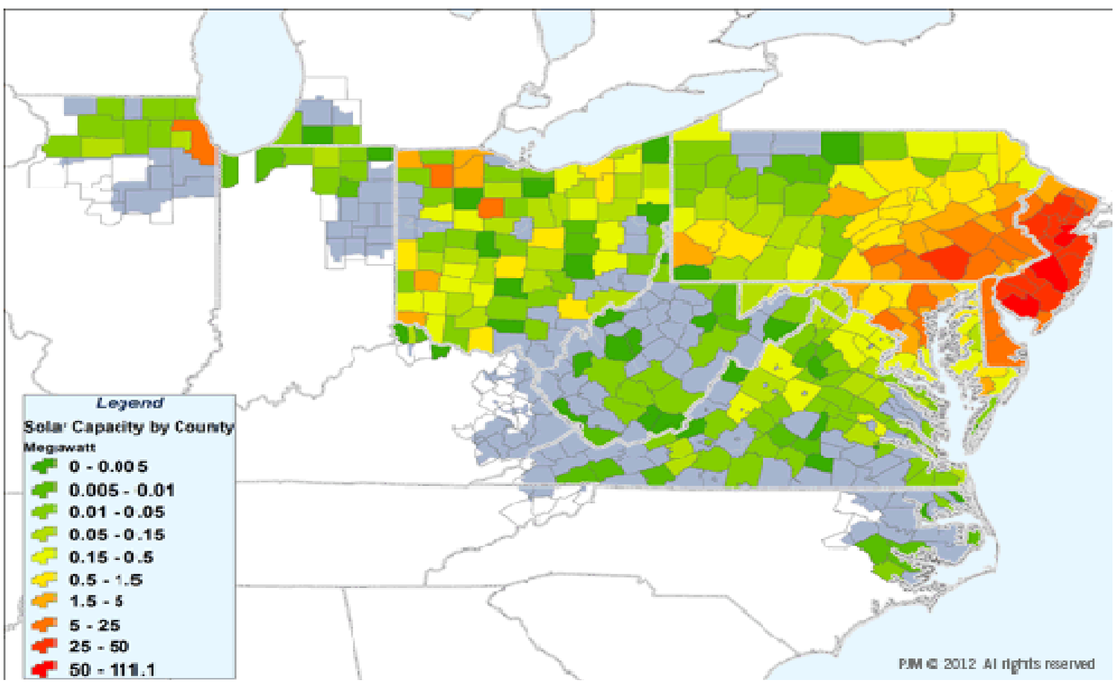
Utility solar plants require less lead time to build than fossil plants. There is not a defined limit to how much utility solar can be built in a given time. However, in practice, solar facilities are not added in an unlimited fashion. **Figure 5D-4** shows the density of solar installations by county, which the vast majority of counties in PJM having less than 1 MW of solar installed. In the period from July 2012 – June 2013, solar photovoltaic constituted less than one-tenth of one percent of total generation in PJM.

For this reason, solar resources were considered available resources with some limits on the rate with which they could be chosen. Utility solar resources were made available up to 50MW of incremental nameplate capacity starting in 2014. To provide some context around that, a typical commercial installation is 50kW and effectively covers the surface of a typical "big box" retailer's roof. A 50 MW utility-scale solar "farm" consumes nearly 150 acres.

As with wind resources, solar resources' useful capacity is less than its nameplate rating. In PJM, that capacity credit is 38% of the nameplate rating. PJM's peak is in the late afternoon, around 5 p.m. well past the point that solar panels are producing at their peak, typically 1 p.m.

Time will tell whether solar can be implemented at a pace that approaches the limits incorporated, or perhaps, even exceed those limits.

Figure 5D-4
Density of Solar Installation by County

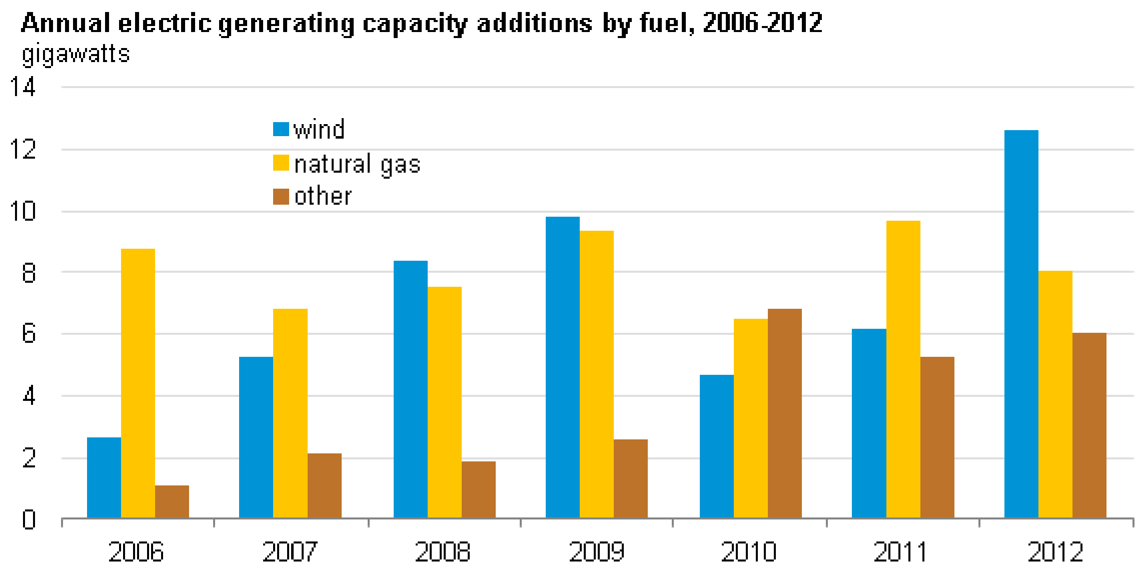


b. Wind

b.1 Modeling Wind Resources

Utility wind energy is generated by wind turbines with a range 1.0 to 2.5 MW, with a 1.5 MW turbine being the most common size used in commercial applications today with over 60,000 MW[12] of wind online in the United States as of December 31, 2012. **Figure 5D-5** shows the annual electric generating capacity additions by fuel.

Figure 5D-5



Typically, multiple wind turbines are grouped in rows or grids to develop a wind turbine power project which requires only a single connection to the transmission system. Location of wind turbines at the proper site is particularly critical as not only does the wind resource vary by geography, but its proximity to a transmission system with available capacity will factor into the cost.

Ultimately, as turbine production increases to match the significant increase in demand, the high capital costs of wind generation should begin to decline. Currently, the cost of electricity from wind generation is becoming competitive within PJM due largely to subsidies, such as the federal production tax credit as well as consideration given to

[12] Data is from the American Wind Energy Association (AWEA) Fourth Quarter 2012 Market Report (http://www.awea.org)

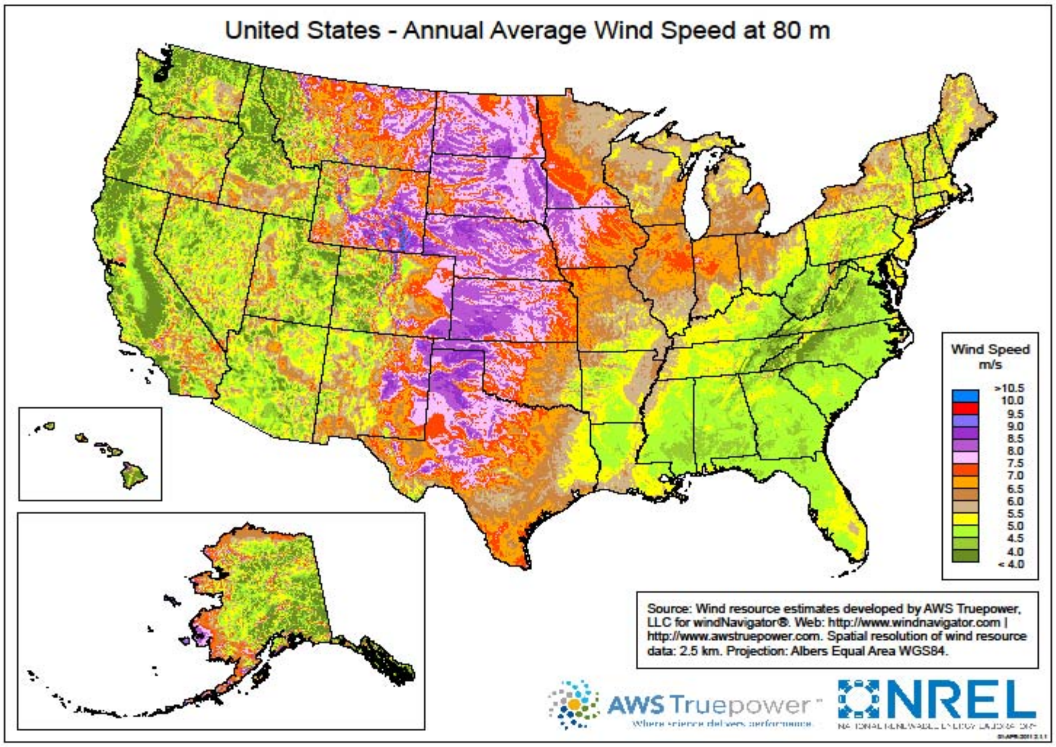
(renewable energy certificate) REC values, if available, anticipated rising fuel costs and potential future carbon costs.

A variable source of power in most non-coastal locales, with capacity factors ranging from 30 to 50 percent, wind energy's life-cycle cost ($/MWh), excluding subsidies, is currently higher than the marginal (avoided) cost of energy, in spite of its negligible operating costs. Another obstacle with wind power is that its most critical factors (i.e., wind speed and sustainability) are typically highest in very remote locations, and this forces the electricity to be transmitted long distances to load centers necessitating the build out of EHV transmission to optimally integrate large additions of wind into the grid. In the PJM region, wind is credited with 13% useful capacity, or wind turbines are, on average, producing at 13% of nameplate capacity at the time of PJM peak. For modeling purposes, wind resources were available in 100MW blocks at a cost of $65/MWh ($2013) with no renewal of the federal production tax credit (PTC) which expires for projects not initiated before year-end 2013.

For this IRP, wind resources are modeled as Purchases Power Agreements (PPAs) with costs at constant real value of $65/MWh which reflects both increased efficiency of the turbines offset by reduced site selection. Similar to solar resources, the implementation of wind resources is limited to a realistic amount, 100 MW, each year. There is no expectation that the Federal Production Tax Credit, which expires at year-end 2013 will be extended. Distributed wind was not modeled for this IRP.

Figure 5D-5 shows the wind resource locations in the U.S. and their relative potential.

Figure 5D-5
United States Wind Power Locations



c. Hydro

The available sources of hydroelectric potential have largely been exploited and those that remain must compete with the other uses, including recreation and navigation. The time associated with environmental studies, permitting for hydroelectric power, high construction costs, and environmental issues (fish and wildlife) make hydro prohibitive at this time. No incremental hydroelectric resources were considered in this IRP.

d. Biomass

Biomass is a term that typically includes organic waste products (sawdust or other wood waste), organic crops (corn, switchgrass, poplar trees, willow trees, etc.), or biogas produced from organic materials, as well as select other materials. Biomass costs will vary significantly depending upon the feedstock. Biomass was not considered an option in this IRP due to prevailing costs.

E. Exhibits 5-1 to 5-6

Exhibit 5-1

INDIANA MICHIGAN POWER COMPANY
GENERATING CAPACITY IN SERVICE (A)

			CAPABILITY (2013) - MW I&M (B)	
PLANT	**UNITS**	**NOTES**	**Winter (F)**	**Summer (E)**
Cook Nuclear	1-2		2,191	2,064
Rockport	1-2		2,227	2,223
Tanners Creek	1-4		995	982
Conventional Hydro			15	11
		Total	5,428	5,280
Capacity Purchases				
Clifty & Kyger (OVEC)	1-6	(C)	174	166
Fowler Ridge Phase 1 (Wind)		(G)	20	19
Fowler Ridge Phase 2 (Wind)		(G)	10	9
Wildcat (Wind)	1-3	(D)	13	13
Robert Mone (Gas)	1-3	(D)	27	7
SEPA (Hydro)			1	1
		Total Purchases	244	215
		Total Incl. Purchases	5,672	5,495

NOTES:
A. Except where stated otherwise, all units are coal fired.
B. I&M plant capabilities based on AEP System Interconnection Agreement pool view.
C. I&M's PPR shares of OVEC purchase.
D. Capability shown for I&M reflects I&M's MLR share of the Mone purchase.
E. Expected capacity at time of I&M Summer 2013 peaks.
F. Expected capacity at time of I&M Winter 2012/2013 peaks.
G. Wind and Solar capacity values are assumed to be 13% and 38% of nameplate or based on historical performance.

Exhibit 5-2

Existing I&M Generating Units (MW)

Summer	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Cook 1	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007
Cook 2	1,057	1,057	1,057	1,107	1,107	1,107	1,107	1,107	1,107	1,107
Rockport 1	1,118	1,118	1,118	1,118	1,148	1,148	1,148	1,148	1,148	1,148
Rockport 2	1,105	1,105	1,105	1,105	1,105	1,105	1,136	1,136	1,136	1,136
Tanners Creek 1	145	-	-	-	-	-	-	-	-	-
Tanners Creek 2	142	-	-	-	-	-	-	-	-	-
Tanners Creek 3	195	-	-	-	-	-	-	-	-	-
Tanners Creek 4	500	-	-	-	-	-	-	-	-	-
Unit Total	5,269	4,287	4,287	4,337	4,367	4,367	4,398	4,398	4,398	4,398

Summer	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Cook 1	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007
Cook 2	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107	1,107
Rockport 1	1,148	1,148	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133
Rockport 2	1,136	1,136	1,136	1,136	1,136	1,136	1,120	1,120	1,120	1,120
Tanners Creek 1	-	-	-	-	-	-	-	-	-	-
Tanners Creek 2	-	-	-	-	-	-	-	-	-	-
Tanners Creek 3	-	-	-	-	-	-	-	-	-	-
Tanners Creek 4	-	-	-	-	-	-	-	-	-	-
Unit Total	4,398	4,398	4,383	4,383	4,383	4,383	4,367	4,367	4,367	4,367

Note: Rockport is based on I&M's portion only (85% of Unit 1 and 85% of Unit 2)
No Unit sales are reflected here

Exhibit 5-3

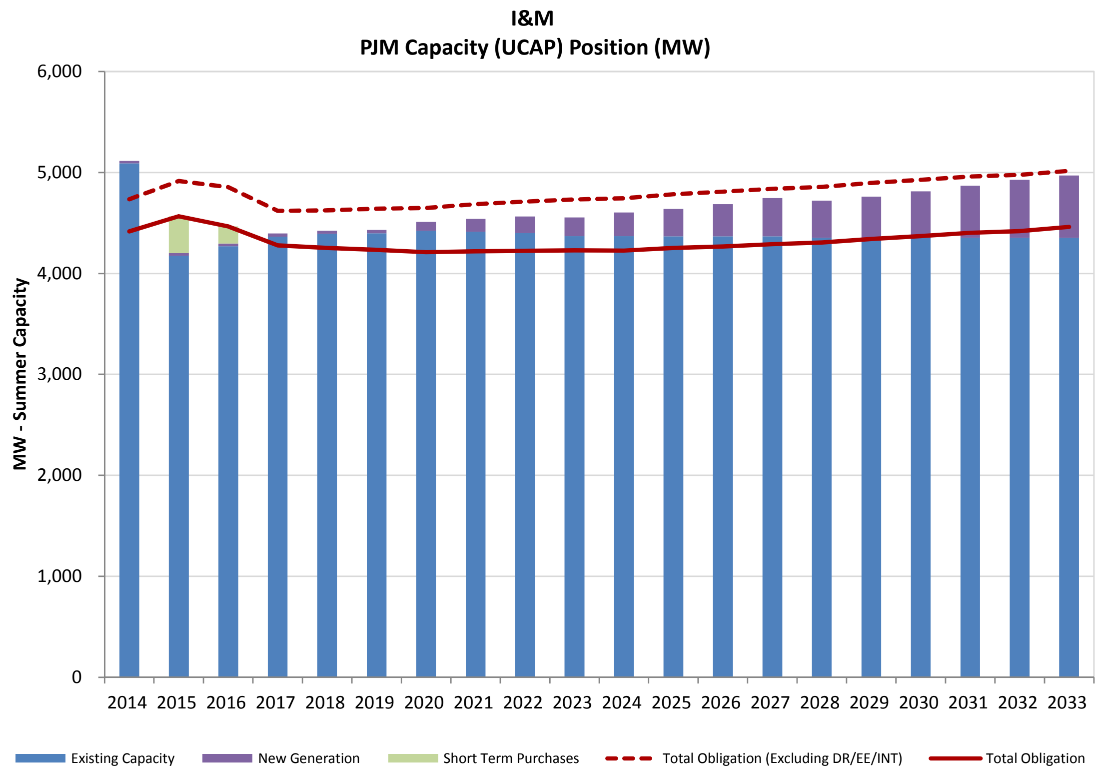

I&M
PJM Capacity (UCAP) Position (MW)
MW - Summer Capacity
6,000
5,000
4,000
3,000
2,000
1,000
0
2014 2015 2016 2017 2018 2019 2020 2021 2022 2023 2024 2025 2026 2027 2028 2029 2030 2031 2032 2033
Existing Capacity
New Generation
Short Term Purchases
Total Obligation (Excluding DR/EE/INT)
Total Obligation

Exhibit 5-4

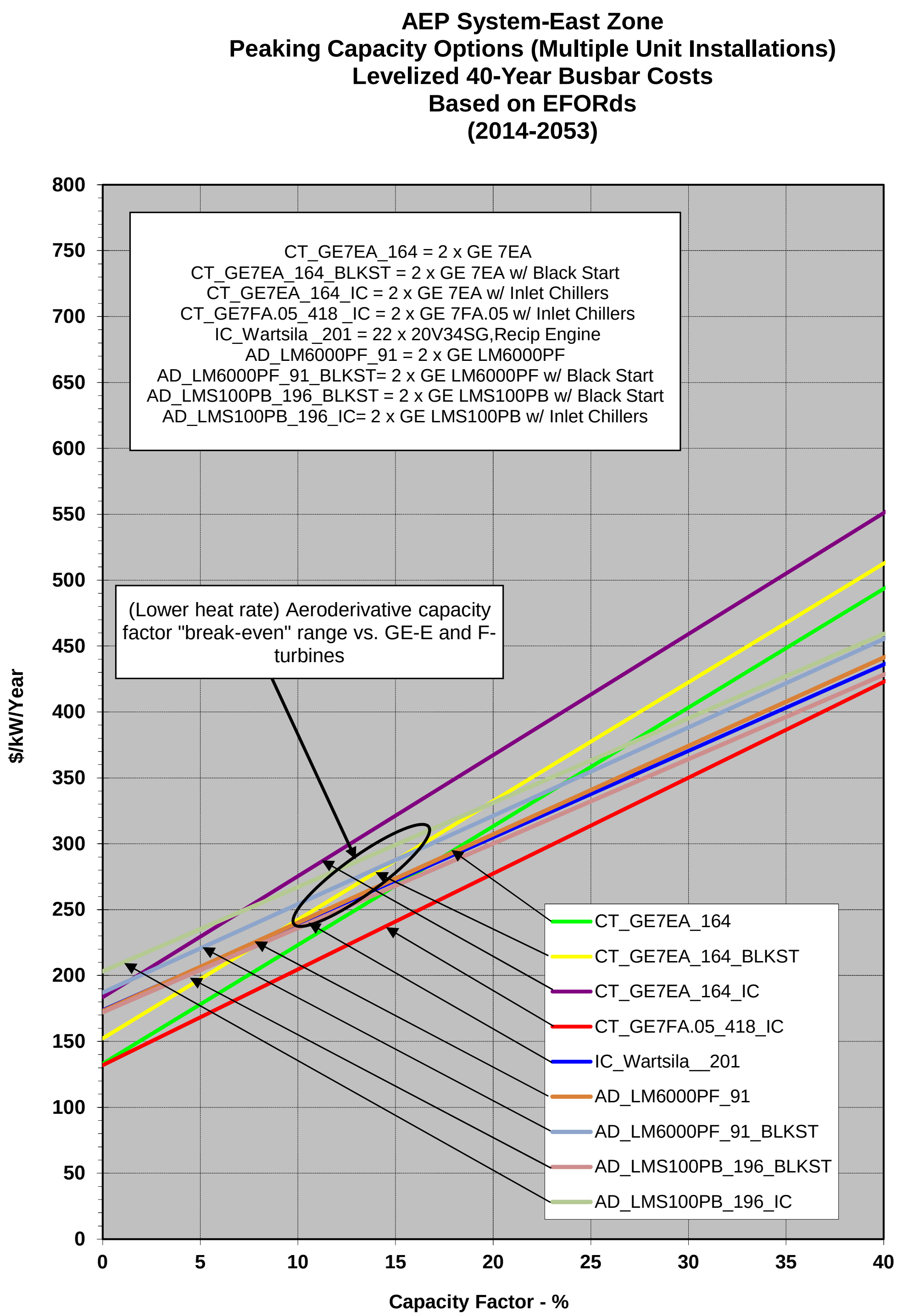

AEP System-East Zone
Peaking Capacity Options (Multiple Unit Installations)
Levelized 40-Year Busbar Costs
Based on EFORds
(2014-2053)
CT_GE7EA_164 = 2 x GE 7EA
CT_GE7EA_164_BLKST = 2 x GE 7EA w/ Black Start
CT_GE7EA_164_IC = 2 x GE 7EA w/ Inlet Chillers
CT_GE7FA.05_418 _IC = 2 x GE 7FA.05 w/ Inlet Chillers
IC_Wartsila _201 = 22 x 20V34SG,Recip Engine
AD_LM6000PF_91 = 2 x GE LM6000PF
AD_LM6000PF_91_BLKST= 2 x GE LM6000PF w/ Black Start
AD_LMS100PB_196_BLKST = 2 x GE LMS100PB w/ Black Start
AD_LMS100PB_196_IC= 2 x GE LMS100PB w/ Inlet Chillers
(Lower heat rate) Aeroderivative capacity factor "break-even" range vs. GE-E and F-turbines
CT_GE7EA_164
CT_GE7EA_164_BLKST
CT_GE7EA_164_IC
CT_GE7FA.05_418_IC
IC_Wartsila__201
AD_LM6000PF_91
AD_LM6000PF_91_BLKST
AD_LMS100PB_196_BLKST
AD_LMS100PB_196_IC
$/kW/Year
0
50
100
150
200
250
300
350
400
450
500
550
600
650
700
750
800
0
5
10
15
20
25
30
35
40
Capacity Factor - %

Exhibit 5-5

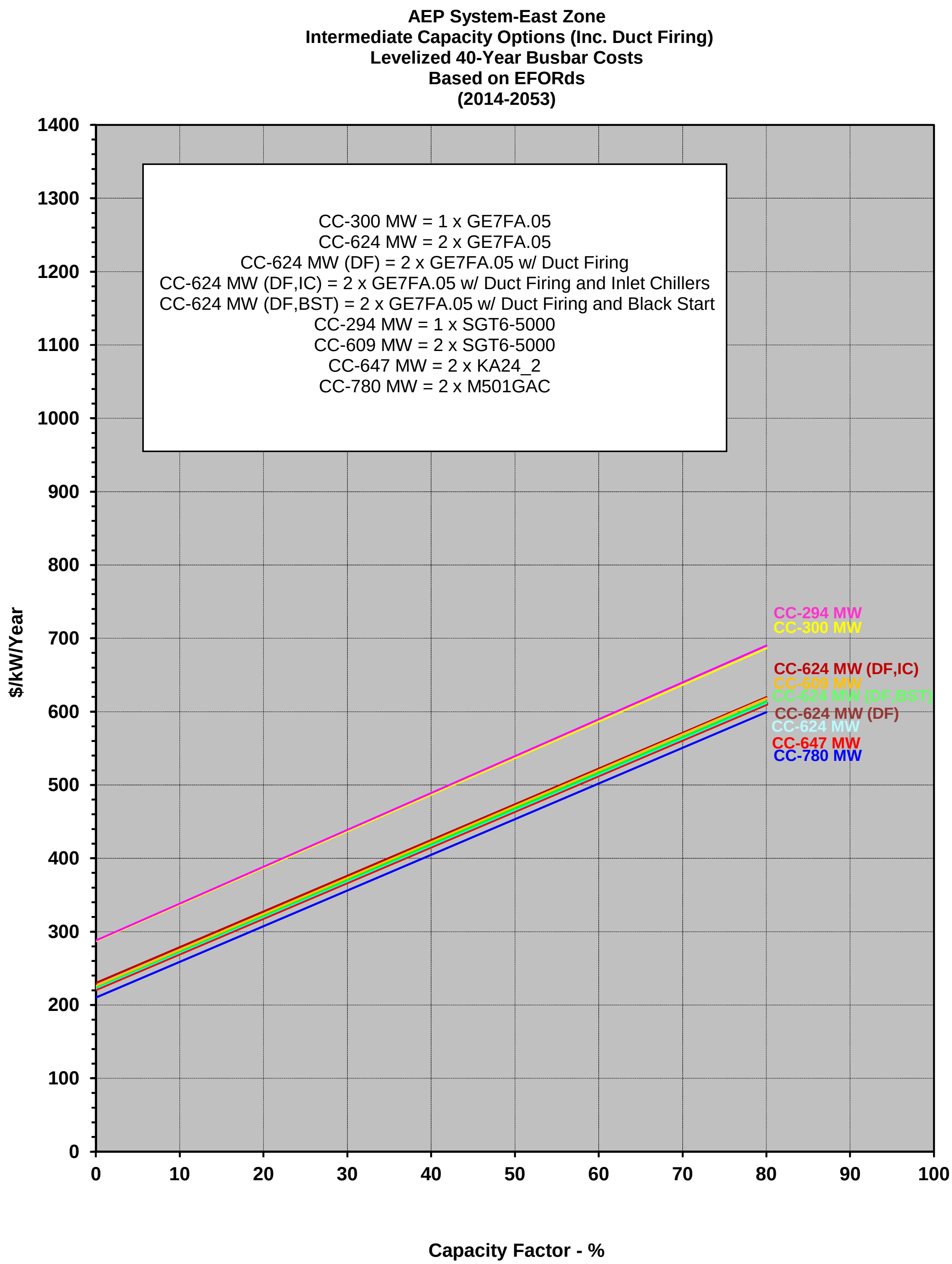
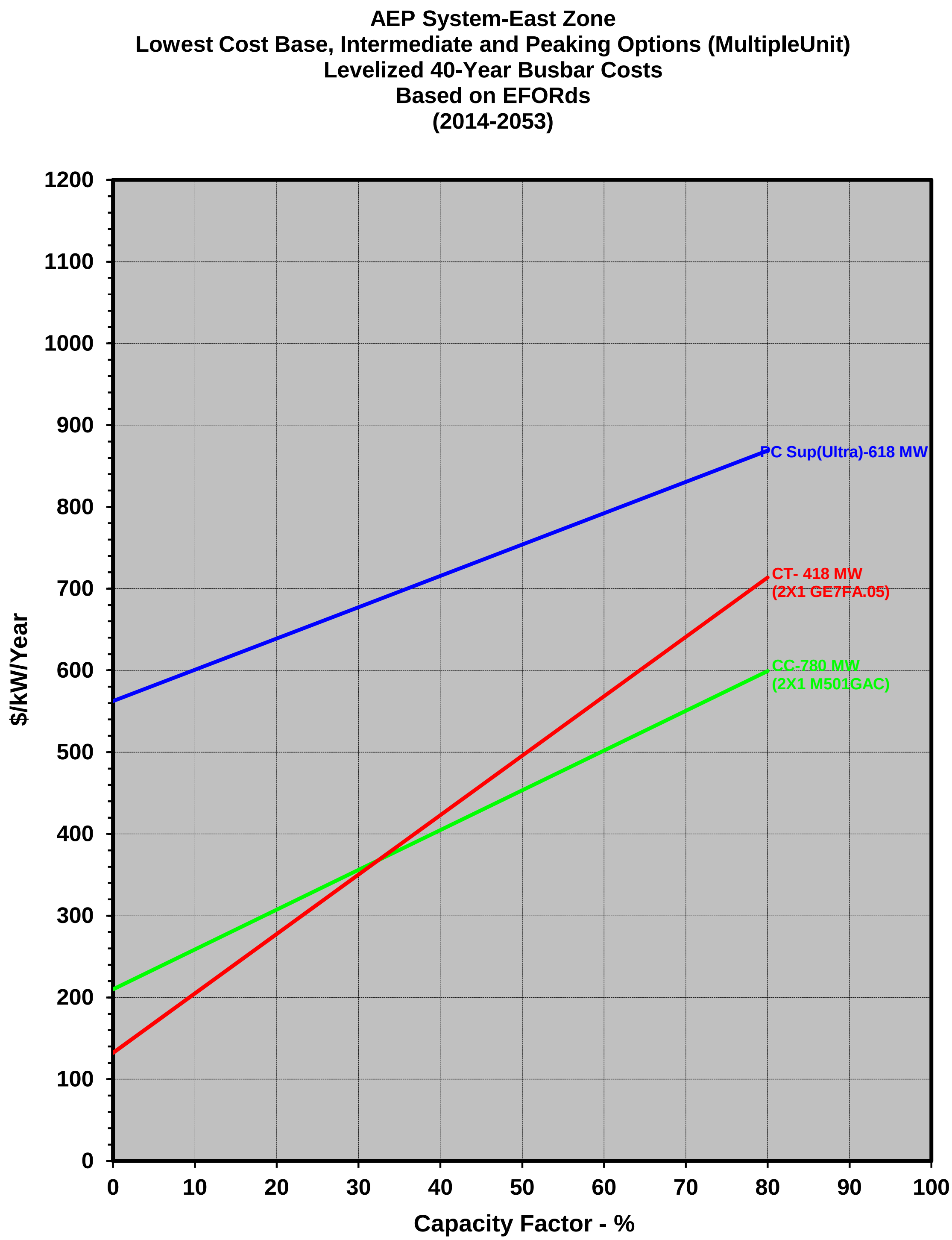

AEP System-East Zone
Intermediate Capacity Options (Inc. Duct Firing)
Levelized 40-Year Busbar Costs
Based on EFORds
(2014-2053)
CC-300 MW = 1 x GE7FA.05
CC-624 MW = 2 x GE7FA.05
CC-624 MW (DF) = 2 x GE7FA.05 w/ Duct Firing
CC-624 MW (DF,IC) = 2 x GE7FA.05 w/ Duct Firing and Inlet Chillers
CC-624 MW (DF,BST) = 2 x GE7FA.05 w/ Duct Firing and Black Start
CC-294 MW = 1 x SGT6-5000
CC-609 MW = 2 x SGT6-5000
CC-647 MW = 2 x KA24_2
CC-780 MW = 2 x M501GAC
CC-294 MW
CC-300 MW
CC-624 MW (DF,IC)
CC-609 MW
CC-624 MW (DF,BST)
CC-624 MW (DF)
CC-624 MW
CC-647 MW
CC-780 MW
$/kW/Year
Capacity Factor - %
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
0
10
20
30
40
50
60
70
80
90
100

Exhibit 5-6


AEP System-East Zone
Lowest Cost Base, Intermediate and Peaking Options (MultipleUnit)
Levelized 40-Year Busbar Costs
Based on EFORds
(2014-2053)
$/kW/Year
Capacity Factor - %
PC Sup(Ultra)-618 MW
CT- 418 MW
(2X1 GE7FA.05)
CC-780 MW
(2X1 M501GAC)
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
0
10
20
30
40
50
60
70
80
90
100

6) Environmental Compliance

A. Introduction

In support of requirements found in **170 IAC 4.7.4(8), 170 IAC 4.7.6(a)(4), 170 IAC 4.7.6(c)(2)-(3), 170 IAC 4.7.8(5), and 170 IAC 4.7.8(9)**, the following information provides background on both current and future environmental regulatory compliance plan issues within the I&M system. The Company's goal is to develop a comprehensive plan that not only allows I&M to meet the future resource needs of the Company in a reliable manner, but also to meet increasingly stringent environmental requirements in a cost effective manner.

B. Solid Waste Disposal

170 IAC 4-7-6(a)(4)(B)

Rockport has an aggressive pollution prevention plan for solid waste generated. Coal combustion by-products (CCBs), comprised of bottom ash captured in the boiler and fly ash captured in the electrostatic precipitator (ESP), totaled approximately 580,566 tons of material in 2012. Prior to 2010, fly ash was produced and marketed for reuse in applications that include flowable fill, ready mix concrete, raw feed for cement manufacture, and structural fills. Fly ash sales ceased beginning in 2010 because the activated carbon injection system (ACI) to control mercury was placed into service. Ash sales could potentially resume in the future if cost-effective methods are developed to lessen the effect of activated carbon on the fly ash properties for reuse. Fly ash is disposed of at the on-site landfill permitted by the Indiana Department of Environmental Management (IDEM). The landfill is underlain with clay, has a groundwater monitoring well system that is sampled to detect any releases to the groundwater, and storm-water runoff collection and treatment systems, with discharges regulated by an IDEM-issued National Pollutant Discharge Elimination System (NPDES) permit. Unused bottom ash is stored for future use in a pond also regulated by an IDEM NPDES permit.

Tanners Creek uses a wet system for all ash handling. Fly ash from all units is sluiced to a fly ash pond southeast of the plant. The pond is underlain with a 20-mil PVC liner and is equipped with ground-water monitoring wells. Bottom ash from Units 1-3 is sluiced to the auxiliary ash pond. Unit 4 boiler slag is sluiced to a reclaim pond adjacent to that unit. Boiler slag is excavated and utilized on a regular basis by an on-site sales contractor. In 2012, CCBs comprised of fly ash, bottom ash, and boiler slag, generated at the plant totaled about 101,304 tons. Effluent from the fly ash, auxiliary, and reclaim ponds is routed to the main ash pond for further treatment prior to discharge to the Ohio River in accordance with the plant's NPDES permit.

The EPA is also reviewing the current rules regarding the treatment of CCBs, which may affect handling and disposal of CCBs in the future. The EPA issued a proposed CCR in June 2010 and a final rule is expected to be available in 2014. Discussion of this rule is available in more detail in part F of this section of the IRP.

Non-hazardous solid wastes from Rockport and Tanners Creek are disposed at permitted municipal solid waste landfills. Numerous non-hazardous and hazardous wastes are recycled, including everything from paper and cardboard to batteries and used mercury.

Typical solid wastes related to hydroelectric generation facilities include trash, solvents, and hydraulic fluid, which are recycled or properly disposed of using licensed vendors.

C. Hazardous Waste Disposal

170 IAC 4-7-6(a)(4)(C) and (D)

Rockport is typically a small-quantity generator of hazardous waste, such as parts washer by-products, batteries, light bulbs, and paints. The plant recycles light bulbs and batteries. Rockport has significantly reduced the amount of solvents generated in the parts washers by purchasing its own equipment and processing its own non-hazardous solvents.

Tanners Creek is typically a conditionally exempt small quantity generator of hazardous wastes, including paints and paint-related waste, mercury waste, light bulbs, batteries, and excess/outdated chemicals. The plant recycles light bulbs, batteries and mercury waste.

For the hydroelectric facilities, hazardous waste is transferred to the Twin Branch hydro facility in Mishawaka, Indiana and stored until disposal by a licensed hazardous waste contractor. Normal variation in monthly waste generation alternates the facility's status between conditionally exempt (typically) to small quantity generator (occasionally). Universal wastes such as lighting and batteries are disposed or recycled by third-party vendors from the facilities.

D. Air Emissions

170 IAC 4-7-6(a)(4)(A)

There are numerous air regulations that have been promulgated or that are under development, which will apply to I&M's facilities, specifically the coal-fired Tanners

Creek and Rockport plants. Currently, air emissions from both plants are regulated by Title V operating permits that incorporate the requirements of the Clean Air Act (CAA) and the SIP. Other applicable requirements include those related to the Clean Air Interstate Rule (CAIR), MATS and the NSR Consent Decree. Several air regulatory programs are under development and will apply to both Rockport and Tanners Creek plants, including those related to the regulation of GHG and revisions to the National Ambient Air Quality Standards (NAAQS) for SO_2, NO_x, fine particulate matter, and ozone.

Potential air emissions at the Rockport Plant are reduced through the use of ESPs, low sulfur coal, low NO_x burners and over-fire air (OFA), as well as a dry fly-ash handling system. An activated carbon injection system to reduce mercury emissions at Rockport, as approved in IURC Cause No. 43636 is also installed. Tanners Creek controls air emissions through the use of ESPs, low sulfur coals, low NO_x combustion systems, and a wet fly-ash handling system. Also, as approved in IURC Cause No. 43636, selective non-catalytic reduction (SNCR) systems at Tanner's Creek Units 1-3 are used to reduce NO_x emissions.

I&M is a party to the IAA, Modification 1, effective 1996. Through this agreement, I&M jointly purchases SO_2 allowances procured for the AEP System-East Zone's (AEP-East) compliance. Additionally, any SO_2 allowance excesses or shortages are sold to or purchased from the other parties to the agreement if needed.

Environmental regulations have expanded beyond those covered by the IAA. For example, the IAA does not cover the allowance program established for emissions of

NO_x. In addition, evolving environmental regulations will likely require unit-specific, rather than system-wide, solutions. For these reasons, on December 17, 2010, in accordance with Section 13.2 of the Pool Agreement, each of the Pool members provided notice to the other members (and to AEPSC, as agent) to terminate the Pool Agreement (which includes the IAA) on January 1, 2014. The termination of the Pool and the IAA is described further in Section 2A.

E. Environmental Compliance Programs

170 IAC 4.7.4(8)

1. Title IV Acid Rain Program

The Title IV Acid Rain Program rules were developed in response to the CAA Amendments of 1990 and required state environmental agencies to promulgate rules implementing the Federal program. The Indiana State Title IV program was established by incorporating federal acid rain regulations by reference in Indiana Administrative Code 326 IAC 21, which created calendar year based compliance programs for reducing SO_2 and NO_x.

The acid rain NO_x reduction program was also implemented using a two-phase approach, with the first phase becoming effective in 1996 and the second phase in 2000. Under the NO_x reduction program, the acid rain rules established annual NO_x rates that varied depending on boiler-type. However, the rules allowed companies to comply with the Title IV NO_x standards by using system wide averaging plans. Rockport employs the combined use of low NO_x burners and sub-bituminous coal to reduce NO_x emissions, while low NO_x burners were installed at Tanners Creek boilers in response to the Title IV

NO_x program.

2. Indiana NOx Budget Program SIP Call

In addition to the Title IV NO_x reduction program, the Indiana NO_x Budget Program SIP Call was designed to reduce the interstate transport of NO_x emissions that were determined to significantly impact downwind ozone concentrations. For those states opting to meet the obligations of the NO_x SIP call through a cap and trade program, the EPA included a model NO_x Budget Trading Program rule (40 CFR 96), which was developed to facilitate cost effective emissions reductions of NO_x from large stationary sources. The NO_x SIP Call rules generally required EGUs to reduce NO_x emissions to a level roughly equivalent to a 0.15-lb/mmBtu emission rate, applicable during the ozone season that runs from May 1st through September 30th each year. The initial compliance deadline for the NO_x SIP Call emission reductions was May 31, 2004. The SIP Call utilized an emissions allowance system that allowed AEP and I&M to comply with the rates by the most cost-effective method, which was either to install control technology, purchase allowances, or a mix of both.

Planning for the NO_x SIP Call allowances and emissions was performed for I&M and AEP-East utilizing the IRP process, review of emissions and control effectiveness, allowance availability, NO_x market prices and proposed regulatory changes. Projected emissions, including any future changes to the NO_x reduction effectiveness, were compared to the available allowance inventory including any potential effects of progressive flow control and projected inventory to determine the amount of allowances that were required to ensure compliance. Flow control provisions were included in the

NO_x SIP Call to discourage excessive use of banked allowances in a particular ozone season. Flow control was triggered if the total number of banked allowances from all sources exceeded 10 percent of the region-wide NO_x emissions budget. Beginning in 2009 with the commencement of CAIR, the NO_x Budget SIP Call Program and progressive flow control ended.

3. Clean Air Interstate Rule (CAIR)

On March 10, 2005, the EPA announced the CAIR, which called for significant reduction of SO_2 and NO_x from EGUs. The CAIR program incorporated three cap-and-trade programs: an ozone season NO_x reduction program that replaced the NO_x SIP Call program, an annual NO_x reduction program, and an annual SO_2 reduction program that was administered through the Title IV Acid Rain Program. In order for I&M to have maintained sufficient allowances to be compliant with the CAIR, it planned necessary to purchase a significant number of allowances on an annual basis.

On July 11th, 2008, the District of Columbia Circuit Court of Appeals issued a ruling vacating the CAIR and remanding the rule back to the EPA for revision. However, on December 23, 2008, the Court indicated in a second ruling that the CAIR was being remanded to EPA for revision and was not being vacated. Planning for compliance at this time for CAIR was necessary, but the Company was mindful that more stringent and restrictive emission policies would likely be the result of the revision.

EPA finalized the Cross State Air Pollution Rule (CSAPR) in 2011 to replace CAIR and reduce the interstate transport of NO_x and SO_2 emissions. The U.S. Court of Appeals for the District of Columbia Circuit vacated CSAPR in August 2012 based on the methodology used to establish emissions reductions and EPA's failure to allow states to develop their own emission reduction plans in the first instance. On June 24, 2013, the U.S. Supreme Court granted EPA's appeal of the D.C. Circuit decision to vacate CSAPR. A decision is not expected until 2014. CAIR requirements remain in place and no immediate action from states or affected sources is expected.

4. MATS Rule

The final MATS Rule became effective on April 16, 2012, with compliance required within three years of this date (with the possibility of a one-year compliance extension in certain circumstances). This rule regulates emissions of hazardous air pollutants (HAPs) from coal and oil-fired electric generating units. HAPs regulated by this rule are: 1) mercury; 2) several non-mercury metals such as arsenic, lead, cadmium and selenium; 3) various acid gases including hydrochloric acid (HCl); and 4) many organic HAPs. The MATS Rule includes stringent emission rate limits for several individual HAPs, including mercury. In addition, this rule contains alternative stringent emission rate limits for surrogates representing two classes of HAPs, acid gases and non-mercury particulate metal HAPs. The surrogates for the non-mercury particulate metal and acid gas HAPs are filterable particulate matter (PM) and HCl respectively. The rule regulates organic HAPs through work practice standards.

In anticipation of these requirements, AEP and I&M successfully tested the ability of ACI to mitigate mercury emissions at the Rockport plant in the spring of 2006. In February of 2009, after already having incurred a significant portion of the capital investment, I&M filed for a Certificate of Public Convenience and Necessity (CPCN) for cost recovery of a permanent ACI system to be installed at the Rockport Plant. The CPCN was granted by the IURC in Cause No. 43636 in July of 2009. I&M later sought a Certificate of Public Convenience and Necessity to install a dry sorbent injection technology to assure compliance with the MATS limitations and to satisfy its obligations under the settlement described below.

5. NSR Settlement

On October 9, 2007, AEP entered into a consent decree with the Department of Justice to settle all complaints filed against AEP and its affiliates of which I&M is included. I&M is bound by this decree to retrofit an SCR and FGD on Rockport Units 1 and 2 by December 31, 2017 and December 31, 2019, respectively. In addition, it was agreed that Tanners Creek Units 1-3 and Tanners Creek 4 would only burn coal with sulfur content no greater than 1.2 lb/mm Btu on an average annual basis. These fuel restrictions are consistent with the current coal supply at these units. Minor changes were made to the Consent Decree in 2009 and 2010 to adjust the compliance dates for Appalachian Power Company's Amos Units 1 and 2 to correspond to actual outage schedules.

On February 22, 2013, AEP, along with the DOJ, EPA, and other parties, filed a proposed (3rd) Modified Consent Decree in the United States District Court for the Southern District of Ohio, Eastern Division. This Modified Consent Decree allows I&M to install DSI on both units at Rockport Plant by April 16, 2015, and defer the installation of high efficiency scrubbers on Units 1 and 2 until December 31, 2025 and December 31, 2028, respectively. In addition, Tanners Creek Unit 4 will either convert to burning natural gas or retire by June 1, 2015.

The Modified NSR Consent Decree also contains annual NO_x and SO_2 caps for the AEP operated coal units for AEP-East, of which I&M is a part. The Modified Consent Decree reduced the SO_2 annual emission caps for the AEP-East units. These annual caps are displayed in **Figure 6E-1** and **6E-2**.

Figure 6E-1:NSR Consent Decree Annual NO_x Cap

Calendar Year	Annual Tonnage Limitations for NO_x
2009	96,000
2010	92,500
2011	92,500
2012	85,000
2013	85,000
2014	85,000
2015	75,000
2016, and each year thereafter	72,000

Figure 6E-2
NSR Modified Consent Decree Annual SO_2 Cap

Calendar Year	Annual Tonnage Limitations for SO_2
2016	145,000
2017	145,000
2018	145,000
2019-2021	113,000
2022-2025	110,000
2026-2028	102,000
2029, and each year thereafter	94,000

The Modified Consent Decree also established annual tonnage limits for SO_2 for the Rockport Plant. These annual caps are displayed in **Figure 6E-3**.

Figure 6E-3
NSR Modified Consent Decree Annual SO_2 Cap for Rockport Plant

Calendar Year	Annual Tonnage Limitations for SO_2
2016	28,000
2017	28,000
2018	26,000
2019	26,000
2020-2025	22,000
2026-2028	18,000
2029, and each year thereafter	10,000

While the Tanners Creek Plant was not required to install specific pollution control technologies, the NSR Consent Decree Annual NO_x cap was the driving factor in the retrofit of Tanners Creek Units 1-3 with SNCR technology.

F. Future Environmental Rules

Several environmental regulations have been proposed that will apply to the electricity generating sector once finalized. The following is not meant to be comprehensive, but lists some of the major issues that will need to be addressed over the forecast period.

1. CCR Rule

The EPA issued a proposed rule in June 2010 to address the management of residual byproducts from the combustion of coal in power plants (coal ash) and captured by emission control technologies, such as FGD. The proposed rule includes specific design and monitoring standards for new and existing landfills and surface impoundments, as well as measures to ensure and maintain the structural integrity of surface impoundment/ponds. The proposed CCR rulemaking would require the conversion of most "wet" ash impoundments to "dry" ash landfills, the relining or closing of any remaining ash impoundment ponds, and the construction of additional waste water treatment facilities by approximately January 1, 2018. I&M anticipates that the CCR Rule —based on the preliminary assumption that these residual materials may be categorized as "Subtitle D," or non-hazardous materials —would require plant modifications and capital expenditures (which are factored into this IRP) to address these requirements by, approximately, the 2018 timeframe. The final rule is expected in 2014.

2. Effluent Limitation Guidelines and Standards (ELG)

The EPA proposed an update to the ELG for the steam electric power generating category in the Federal Register on June 7, 2013. The ELG would require more stringent controls on certain discharges from certain EGUs and will set technology-based limits for waste water discharges from power plants with a main focus on process and wastewater from FGD, fly ash sluice water, bottom ash sluice water and landfill/pond leachate. I&M anticipates that wastewater treatment projects will be necessary at the Rockport units and these have been considered as part of the respective long-term unit evaluations The final rule is expected in 2014.

3. Clean Water Act "316(b)" Rule

A proposed rule for the Clean Water Act 316(b) was issued by the EPA on March 28, 2011, and final rulemaking is expected in late 2013. The proposed rule prescribes technology standards for cooling water intake structures that would decrease interference with fish and other aquatic organisms. Given that I&M's Rockport units are already equipped with natural draft, hyperbolic cooling towers, the most significant potential impact of the proposed rule would be the need to install additional fish screening at the front of the water intake structure. As proposed, compliance requirements for the Cook Nuclear Plant would to be determined based on a site-specific study. The implementation schedule for this rule could extend late into this decade due to the site specific nature of the permitting process.

4. NAAQS

The Clean Air Act requires the EPA to establish and periodically review NAAQS designed to protect public health and welfare. Several NAAQS have been recently revised or are under review, which could lead to more stringent SO_2 and NO_x limits. This includes NAAQS for SO_2 (revised in 2010), NO_2 (revised in 2010), fine particulate matter (revised in 2012), and ozone (expected to be revised in 2014). The scope and timing of potential requirements is uncertain.

5. GHG Regulations

For many years, the potential for requirements to reduce greenhouse gas emissions, including carbon dioxide, has been one of the most significant issues facing I&M and AEP. The EPA proposed GHG NSPS for fossil fuel-fired electric generating units in April, 2012. This proposed rule applies only to new sources and proposed an emission standard based on the performance of new natural gas combined cycle units. The EPA did not finalize this rule as expected in the second quarter of 2013. However, on June 25, 2013 President Obama announced a plan to address GHG emissions from fossil-fired power plants. Under President Obama's direction, the EPA issued a revised proposal for the GHG NSPS for new sources on September 20, 2013 and must finalize them in a "timely fashion". For existing sources, the EPA was directed to propose guidelines by June 1, 2014 and finalize those standards by June 1, 2015. States would develop and submit a plan to EPA for implementing the existing source standards by June 30, 2016. The scope and timing of these requirements have not yet been determined. Such GHG rules could impose greater operating costs on I&M's power plants in future years, either through retrofit costs or efficiency requirements. The final rule is expected in 2013.

G. I&M Environmental Compliance

This 2013 IRP considers the impacts of final and proposed EPA regulations to I&M generating facilities. In addition, the IRP development process assumes there will be future regulation of GHG/CO_2 emissions which would become effective at some point in the 2022 timeframe. Emission compliance requirements have a major influence on the consideration of new supply-side resources for inclusion in the IRP because of the potential significant effects on both capital and operational costs. Moreover, the cumulative cost of complying with these rules will ultimately have an impact on proposed retirement dates of existing coal-fueled units that would otherwise be forced to install emission control equipment, as evident with the accelerated planned retirements of Tanners Creek Units 1 through 4.

On August 1, 2011, I&M filed with the IURC in Cause No. 44033 a request for a Certificate of Public Need and Necessity indicating that the best course for I&M customers and for I&M compliance is to install a FGD and SCR at one of the Rockport units. Upon further review and analysis and modification to the NSR Consent Decree (as discussed in Section 6.E.5), it was determined that installation of DSI systems at both units at Rockport and deferral of the installation of high efficiency scrubbers until December 31, 2025, and December 31, 2028, would be the most cost-effective scenario. Hence Cause No. 44033 was withdrawn and Cause No. 44331 was filed seeking a Certificate of Public Need and Necessity for the installation of DSI on the Rockport units in 2015.

In addition, through subsequent evaluation, it was determined that Tanners Creek Unit 4 will retire by June 1, 2015 with the other Tanners Creek units already scheduled for retirement. AEP is actively undertaking implementation of this compliance plan for I&M to meet proposed and final EPA regulations.

H. Rockport and Tanners Creek Air Emissions

In accordance with requirements found in **170 IAC 4-7-6(a)(4)(A)**, projections of SO_2, NO_X, mercury, and CO_2 emissions are provided in **Exhibit 11-1** in the Appendix.

7) Electric Transmission Forecast

A. General Description

(170 IAC 4-7-4(12))

The AEP East Transmission System (eastern zone) consists of the transmission facilities of the six eastern AEP operating companies (APCo, OPCo, I&M, KPCo, Wheeling Power Company and Kingsport Power Company). This portion of the Transmission System is composed of approximately 15,000 miles of circuitry operating at or above 100 kV. The eastern zone includes over 2,100 miles of 765 kV overlaying 3,800 miles of 345 kV and over 8,900 miles of 138 kV circuitry. This expansive system allows AEP to economically and reliably deliver electric power to approximately 24,200 MW of customer demand connected to the AEP eastern Transmission System that takes transmission service under the PJM open access transmission tariff.

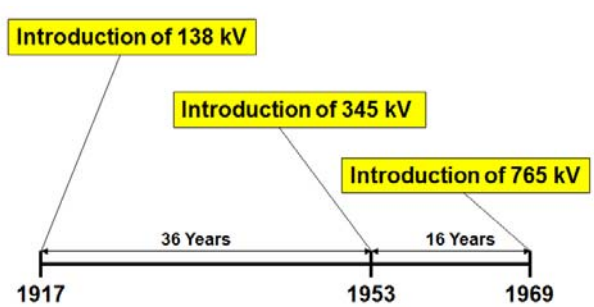
The AEP eastern Transmission System is part of the Eastern Interconnection; the most integrated transmission system in North America. The entire AEP eastern Transmission System is located within the Reliability*First* (RFC) geographic area. On October 1, 2004, AEP's eastern zone joined the RTO and now participates in the PJM markets.

As a result of the AEP eastern Transmission System's geographical location and expanse as well as its numerous interconnections, the eastern Transmission System can be influenced by both internal and external factors. Facility outages, load changes, or generation re-dispatch on neighboring companies' systems, in combination with power transactions across the interconnected network, can affect power flows on AEP's transmission facilities. As a result, the AEP eastern Transmission System is designed and operated to perform adequately even with the outage of its most critical transmission elements or the unavailability of generation. The eastern Transmission System conforms to the NERC Reliability Standards and applicable RFC standards and performance criteria.

Despite the robust nature of the eastern Transmission System, certain outages coupled with extreme weather conditions and/or power-transfer conditions can potentially stress the system beyond acceptable limits. The most significant transmission enhancement to the AEP eastern Transmission System over the last few years was completed in 2006. This was the construction of a 90-mile 765 kV transmission line from Wyoming Station in West Virginia to Jacksons Ferry Station in Virginia. In addition, EHV/138 kV transformer capacity has been increased at various stations across the eastern Transmission System.

AEP's eastern Transmission System assets are aging. **Figure 7A-1** demonstrates the development of AEP's eastern Transmission Bulk Electric System. In order to maintain reliability, significant investments will have to be made in the rehabilitation of existing assets over the next decade.

Figure 7A-1



Over the years, AEP, and now PJM, entered into numerous study agreements to assess the impact of the connection of potential merchant generation to the eastern Transmission System. Currently, there is more than 26,000 MW of AEP generation and approximately 6,000 MW of additional merchant generation connected to the eastern Transmission System. AEP, in conjunction with PJM, has interconnection agreements in the AEP service territory with several merchant plant developers for approximately 1,000 MW of additional generation to be connected to the eastern Transmission System over the next several years. There are also significant amounts of merchant generation under study for potential interconnection.

The integration of the merchant generation now connected to the eastern Transmission System required incremental transmission system upgrades, such as installation of larger capacity transformers and circuit breaker replacements. None of these merchant facilities required major transmission upgrades that significantly increased the capacity of the transmission network. Other transmission system enhancements will be required to match general load growth and allow the connection of large load customers and any other generation facilities. In addition, transmission modifications may be required to address changes in power flow patterns and changes in local voltage profiles resulting from operation of the PJM and Midwest ISO markets.

The announced retirement of 13,000 MW of generation in PJM, including 495 MW at Tanners Creek plant, will result in the need for power to be transmitted over a longer distance into the Fort Wayne, Indiana metro area. In addition, these retirements will result in the loss of dynamic voltage regulation. Since there is no baseload generation near Fort Wayne, Indiana, these retirements could be significant. The retirement of these units would require the addition of a 765 kV source near Fort Wayne to provide a ramp for step-down of power from AEP’s strong 765 kV network. In addition, within the eastern Transmission System, there are two areas in particular that could require significant transmission enhancements to allow the reliable integration of large generation facilities:

- Southern Indiana—there are limited transmission facilities in southern Indiana relative to the AEP generation resources, and generation resources of others in the area. Significant generation additions to AEP’s transmission facilities (or connection to neighbor’s facilities) will likely require significant transmission enhancements, including Extra-High Voltage (EHV) line construction, to address thermal and stability constraints. The Joint Venture Pioneer Project would address many of these concerns. The Pioneer Transmission, LLC is a joint venture formed by Duke Energy and AEP in 2008 to build and operate approximately 240 miles of EHV 765 kV transmission lines and related facilities in Indiana.

- Megawatt Valley—the Gavin/Amos/Mountaineer/Flatlick area currently has stability limitations during multiple transmission outages. Multiple overlapping transmission outages will require the reduction of generation levels in this area to ensure continued reliable transmission operation, although such conditions are expected to occur infrequently. Significant generation resource additions in the Gavin/Amos/Mountaineer/Flatlick area will also influence these stability constraints, requiring transmission enhancements–possibly including the construction of EHV lines and/or the addition of multiple large transformers– to more fully integrate the transmission facilities in this generation-rich area. Thermal constraints will also need to be addressed.

Furthermore, even in areas where the transmission system is robust, care must be taken in siting large new generating plants in order to avoid local transmission loading problems and excessive fault duty levels.

The transmission line circuit miles in Indiana include approximately 600 miles of 765 kV, 1,380 miles of 345 kV, and 1,430 miles of 138 kV lines, as well as over 400 miles of 69 kV and approximately 600 miles of 34.5 kV lines. Confidential **Exhibit 7** displays a map of the entire AEP System-East Zone transmission grid, including I&M.

B. Transmission Planning Process

(170 IAC 4-7-4(10), (11), (13); 4-7-6(d) (2) and 170 IAC 4-7-4(13))

AEP and PJM coordinate the planning of the transmission facilities in the AEP System-East Zone through a "bottom up/top down" approach. AEP will continue to develop transmission expansion plans to meet the applicable reliability criteria in support of PJM's transmission planning process. PJM will incorporate AEP's expansion plans with those of other PJM member utilities and then collectively evaluate the expansion plans as part of its Regional Transmission Expansion Plan (RTEP) process. The PJM assessment will ensure consistent and coordinated expansion of the overall bulk transmission system within its footprint. In accordance with this process, AEP will continue to take the lead for the planning of its local transmission system under the provisions of Schedule 6 of the PJM Operating Agreement (OA). By way of the RTEP, PJM will ensure that transmission expansion is developed for the entire RTO footprint via a single regional planning process, assuring a consistent view of needs and expansion timing while minimizing expenditures. When the RTEP identifies system upgrade requirements, PJM determines the individual member's responsibility as related to construction and costs to implement the expansion. This process identifies the most appropriate, reliable and economical integrated transmission reinforcement plan for the entire region while blending the local expertise of the transmission owners such as AEP with a regional view and formalized open stakeholder input.

AEP's transmission planning criteria is consistent with NERC and Reliability*First* reliability standards. The AEP planning criteria are filed with FERC annually as part of AEP's FERC Form 715 (Confidential Exhibit 3) and these planning criteria are posted on the AEP website.[13] Using these criteria, limitations, constraints and future potential deficiencies on the AEP transmission system are identified. Remedies are identified and budgeted as appropriate to ensure that system enhancements will be timed to address the anticipated deficiency.

PJM also coordinates its regional expansion plan on behalf of the member utilities with the neighboring utilities and/or RTOs, including the Midwest ISO, to ensure inter-regional reliability. The Joint Operating Agreement between PJM and the Midwest ISO provides for joint transmission planning.

C. System-Wide Reliability Measure

(170 IAC 4-7-4 (15); 4-7-6(a) (6) (B) and (C); 4-7-6(d) (2))

At the present time, there is no single measure of system-wide reliability that covers the entire system (transmission, distribution, and generation). However, in practice, transmission reliability studies are conducted routinely for seasonal, near-term, and long-term horizons to assess the anticipated performance of the transmission system.

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[13]http://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/GuideLines/2013%20AEP%20PJM%20FERC%20715_Final_Part%204.pdf

The reliability impact of resource adequacy (either supply or demand side) would be evaluated as an inherent part of these overall reliability assessments. If reliability studies indicate the potential for inadequate transmission reliability, transmission expansion alternatives and/or operational remedial measures would be identified.

D. Evaluation of Adequacy for Load Growth

(170 IAC 4-7-4(14); 4-7-6(a) (6) (A-C); 4-7-6(d) (1))

As part of the on-going near-term/long-term planning process, AEP uses the latest load forecasts along with information on system configuration, generation dispatch, and system transactions to develop models of the AEP transmission system. These models are the foundation for conducting performance appraisal studies based on established criteria to determine the potential for overloads, voltage problems, or other unacceptable operating problems under adverse system conditions. Whenever a potential problem is identified, AEP seeks solutions to avoid the occurrence of the problem. Solutions may include operating procedures or capital transmission reinforcements. Through this on-going process, AEP works diligently to maintain an adequate transmission system able to meet forecasted loads with a high degree of reliability.

In addition, PJM performs a Load Deliverability assessment on an annual basis using a 90/10[14] load forecast for areas that may need to rely on external resources to meet their demands during an emergency condition.

E. Evaluation of Other Factors

(170 IAC 4-7-4(14); 4-7-6(a) (6) (A-C); 4-7-6(d) (1))

[14] 90% probability that the peak actual load will be lower than the forecasted peak load and 10% probability that the acutal peak load will be higher than the forecasted peak load.

As a member of PJM, and in compliance with FERC Orders 888 and 889, AEP is obligated to provide sufficient transmission capacity to support the wholesale electric energy market. In this regard, any committed generator interconnections and firm transmission services are taken into consideration under AEP's and PJM's planning processes. In addition to providing reliable electric service to AEP's retail and wholesale customers, PJM will continue to use any available transmission capacity in AEP's eastern transmission system to support the power supply and transmission reliability needs of the entire PJM – Midwest ISO joint market.

A number of generation requests have been initiated in the PJM generator interconnection queue. AEP currently has 20 active queue positions within Indiana totaling approximately 5,343 MW (nameplate), including projects that are either in various stages of study (16 projects), under construction (3 projects), or in-service (1 project). Of these 20 active queue positions, 15 are wind generation requests. AEP, through its membership in PJM, is obligated to evaluate the impact of these projects and construct the transmission interconnection facilities and system upgrades required to connect any projects that sign an interconnection agreement. The amount of this planned generation that will actually come to fruition is unknown at this time.

F. Transmission Expansion Plans

(170 IAC 4-7-6(a) (6) (A); 4-7-6(d) (1))

The transmission system expansion plans for the AEP eastern system are developed to meet projected future requirements. AEP uses power flow analyses to simulate normal conditions, and credible single and double contingencies to determine the potential thermal and voltage impact on the transmission system in meeting the future requirements.

As discussed earlier, AEP will continue to develop transmission reinforcements to serve its own load areas, in coordination with PJM, to ensure compatibility, reliability and cost efficiency.

G. Transmission Project Descriptions

(170 IAC 4-7-6(d) (3) and (4))

A detailed list and discussion of the AEP transmission projects that have recently been completed or presently underway in Indiana can be found under Chapter 7(I) (Indiana Transmission Projects) of this report. In addition, several other projects beyond the I&M area have also been completed or are underway across the AEP System-East Zone. While they do not directly impact I&M, such additions contribute to the robust health and capacity of the overall transmission grid, which also benefit Indiana customers.

AEP's transmission system is anticipated to continue to perform reliably for the upcoming peak load seasons. AEP will continue to assess the need to expand its system to ensure adequate reliability for I&M's customers within the State of Indiana. AEP anticipates that incremental transmission expansion will continue to provide for expected load growth.

H. FERC Form 715 Information

A discussion of the eastern AEP System reliability criteria for transmission planning, as well as the assessment practice used, is provided in AEP's FERC Form 715

Annual Transmission Planning and Evaluation Report, 2013 filing. That filing also provides transmission maps, and pertinent information on power flow studies and an evaluation and continued adequacy assessment of AEP's eastern transmission system. Pertinent excerpts from this report to meet the 170 IAC requirements are contained in Exhibit 3 of the Confidential Supplement.

As the Transmission Planner for AEP and AEP subsidiaries in the east, PJM performs all required studies to assess the robustness of the Bulk Electric System. All the models used for these studies are created by and maintained by PJM with input from all Transmission Owners, including AEP and its subsidiaries. Any request for current cases, models, or results should be requested from PJM directly. PJM is responsible for ensuring that AEP meets all NERC transmission planning requirements, including stability of the system.

Performance standards establish the basis for determining whether system response to credible events is acceptable. Depending on the nature of the study, one or more of the following performance standards will be assessed: thermal, voltage, relay, stability, and short circuit. In general, system response to events evolves over a period of several seconds or more. Steady state conditions can be simulated using a power flow computer program. A short circuit program can provide an estimate of the large magnitude currents, due to a disturbance, that must be detected by protective relays and interrupted by devices such as circuit breakers. A stability program simulates the power and voltage swings that occur as a result of a disturbance, which could lead to undesirable generator/relay tripping or cascading outages. Finally, a post contingency power flow study can be used to determine the voltages and line loading conditions following the removal of faulted facilities and any other facilities that trip as a result of the initial disturbance.

The planning process for AEP's transmission network embraces two major sets of contingency tests to ensure reliability. The first set, which applies to both bulk and local area transmission assessment and planning, includes all significant single contingencies. The second set, which is applicable only to the Bulk Electric System, includes multiple and more extreme contingencies. For the eastern AEP transmission system, thermal and voltage performance standards are usually the most constraining measures of reliable system performance.

Sufficient modeling of neighboring systems is essential in any study of the Bulk Electric System. Neighboring company information is obtained from the latest regional or interregional study group models, the RFC base cases, the Eastern Interconnection Reliability Assessment Group (ERAG) and the Multiregional Modeling Working Group (MMWG) power flow library, the PJM base cases, or the neighboring company itself. In general, sufficient detail is retained to adequately assess all events, outages and changes in generation dispatch, which are contemplated in any given study.

I. Indiana Transmission Projects

(170 IAC 4-7-6(d)(3) and (4))

A brief summary of the transmission projects in I&M's Indiana service territory for the 2011-2015 time-frame is provided below. Project information includes the project name, a brief description of the project scope, projected in-service date, and projected cash flows[15] by year for each project.

- Mishawaka Area Improvements: Several 138 kV and 34.5 kV line overloads in the Elkhart area were identified by both PJM and AEP due to an outage of East Elkhart 345/138 kV transformer. Construction of a new 15 mile Twin Branch – East Elkhart 138 kV circuit using the vacant side of the existing tower line and developing a new 138/34.5 kV Station, Capital Avenue, to interconnect the existing 34.5 kV network will help alleviate these conditions. As part of the proposal, the distribution load will also be consolidated at the new 138/34.5 kV Capital Avenue station and the existing Currant Road station will be retired.
    - 2011: $0.5 million
    - 2012: $18.9 million
    - 2013: $14.4 million
    - 2014: $1.9 million
- South Side and South Bend Upgrades: PJM identified overloads on the Twin Branch – South Bend 138 kV line and the Jackson Road – South Side 138 kV line. To alleviate these overloads, AEP will replace terminal equipment at South Side and South Bend stations and perform a sag study on the Twin Branch – South Bend 138 kV line and the Jackson Road – South Side 138 kV line to improve the summer emergency rating of both lines.
    - 2013: $0.5 million
    - 2014: $0.5 million

- Northern Fort Wayne Improvements: PJM and AEP identified overloads on the Auburn – Dekalb 138 kV circuit for loss of two 138 kV sources into the Northern Fort Wayne area. AEP has also demonstrated that several contingencies in the area can cause severe thermal overload and voltage conditions and a possible blackout in Northern Fort Wayne jeopardizing the

[15] Please note that cash flows are approximated.

bulk electric system (BES) in Indiana. To mitigate this potential situation, AEP will establish two new stations; a 138/69 kV station located near Auburn, Indiana and a 138 kV switching station near Huntertown, Indiana. The new station near Huntertown, Indiana will be connected to existing 138 kV lines from Robison Park and will thus serve as a source. A new double circuit line will be constructed from this station to the new 138/69 kV station and eventually to Auburn 138 kV station to provide an additional source for Northern Fort Wayne area. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.

  - 2012: $2.0 million
  - 2013: $10.0 million
  - 2014: $15.0 million
  - 2015: $5.0 million

- Southern Indiana Improvements: AEP is noticing a change in the flow patterns in the southern Indiana area. The 765 kV outlets were not originally designed for the flow pattern of heavy west to east flows. The root cause of this change in flow patter is the addition of over 25GW of generation around southern Indiana, southern Illinois and western Kentucky since 1989. Also, since the transmission facilities sit at the seams of Midwest ISO and PJM, high voltages are experience on the 345 kV network. The proposed improvements including the change in shunt reactor size at Rockport and transposition of 765 kV lines will help mitigate these constraints. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
  - 2011: $7.7 million
  - 2012: $29.3 million
  - 2013: $3.5 million
- Ball State University Load Increase: Ball State University is increasing its

load to accommodate a geothermal project on campus and conversion to 12 kV service. To serve this load, AEP is rebuilding the Tillotson 34.5 kV station and replacing the underground cables that feed Ball State's Christy Woods station. This will allow for future load growth and replaces an old, deteriorating station. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.

- 2013: $5.0 million
- 2014: $6.0 million

- Greater Fort Wayne Area Improvements: PJM identified low voltage violations at numerous buses in the greater Fort Wayne area in the 2015 case study. AEP is proposing to expand the existing Sorenson station and establish a new 765 kV source to the area to mitigate the future voltage concerns. The new source at Sorenson requires a new 345 kV path to be constructed between Sorenson and Robison Park stations. This new 345 kV line will be completed by rebuilding an existing 138 kV line between the two stations as a double-circuit tower line. One side of the new line at 345 kV and the other side will remain 138 kV to serve existing stations along the path. This project is a joint project with I&M Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
    - 2013: $4.0 million
    - 2014: $30.0 million
    - 2015: $20.0 million
- Allen Station Expansion: PJM identified overloads on several 138 kV lines in the 2016 study case. AEP's proposed solution includes a station expansion and transformer addition to the existing Allen station. Several miles of 138 kV line will be constructed to help alleviate local overloads identified by PJM. This project is a joint project with I&M Transmission Company, Ohio Power,

and Ohio Transmission Company. The cash flows listed below are only for the I&M portion of the project and exclude the other portions.

- 2013: $0.3 million
- 2014: $4.6 million
- 2015: $2.3 million
- 2016: $2.5 million

- Randolph Area Improvements: PJM identified low voltage violations in the Randolph, IN area in the 2015 study case. AEP is proposing to expand Selma Parker station and installing a 138/69 kV transformer to introduce a new source to the area to alleviate the low voltage violations. This project is a joint project with I&M Transmission Company. The cashflows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
    - 2013: $0.5 million
    - 2014: $5.0 million
    - 2015: $2.0 million
- Daleville Area Improvements: PJM identified overloads on the Desoto – Madison 138 kV circuit. To fix the overload, AEP will replace terminal equipment at Daleville station and perform a sag study on the line.
    - 2013: $1.0 million
    - 2014: $0.5 million
- City of Fort Wayne Improvements: To better serve the customers in the downtown Fort Wayne area, AEP is proposing to introduce a second 138 kV source to Spy Run station by rebuilding an existing 34.5 kV line as a double circuit tower line. One side will be operated at 138 kV while the other will remain at 34.5 kV. The 34.5 kV network will also be upgraded as needed to accommodate the new 138 kV source and rearrangement of the distribution network. This project is a joint project with I&M Transmission Company. The cashflows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.

- 2013: $3.3 million
- 2014: $9.4 million
- 2015: $10.5 million

- Southern Fort Wayne Improvements: AEP is proposing to convert an aging 34.5 kV line to 69 kV. The stations currently served from the 34.5 kV line will also be converted to 69 kV. This will eliminate future voltage concerns and allow for the retirement of aging infrastructure. This project is a joint project with I&M Transmission Company. The cashflows listed below are only for the I&M portion of the project and exclude the I&M Transmission Company portion.
  - 2013: $0.3 million
  - 2014: $10.7 million
  - 2015: $7.2 million

The following provides an update for each of the transmission projects provided in the 2011 IRP. All of the projects have been completed and are now in-service.

- Lincoln Breaker Upgrade: PJM identified the Lincoln 138 kV breaker D as being over dutied and over loaded under certain contingency conditions. AEP replaced Lincoln 138 kV breaker D, the risers and cross bus sections of the Lincoln – Allen 138 kV circuit at Lincoln station.
- Industrial Park – McKinley Upgrades: PJM identified an overload on the McKinley – Industrial Park 138 kV circuit. AEP replaced risers at McKinley and Industrial Park 138 kV stations and perform a sag study on the McKinley – Industrial Park 138 kV line. This will help improve the emergency rating of the 138 kV line to deal with contingency situations in the area.

- Local Sag Studies: PJM identified overloads on several 138 kV lines that required sag and structure analysis to increase the emergency operating temperature of these lines. The lines studied include:
    - Delaware – Madison 138 kV,
    - Desoto – Deer Creek 138 kV,
    - Desoto – Madison 138 kV,
    - Sorenson – Keystone 345 kV,
    - Sorenson – McKinley 138 kV,
    - Sorenson – Industrial Park 138 kV,
    - Huntington Junction – Sorenson 138 kV,
    - Albion – Robison Park 138 kV,
    - Harper – Hacienda 138 kV, and
    - Jackson Road – Concord 138 kV
- Strawton Wind Farm: PJM IPP project U3-002 signed Interconnection Service Agreement (ISA) and was operational at the end of 2012. This wind farm connected to the Deer Creek – Fisher Body – Mullin 138 kV line. In addition to the wind farm connection, station improvements were made at Mullin station and at Fisher Body station.

8) Selection of the Resource Plan

(170 IAC 4-7-8)

A. Modeling Approach

1. *Plexos®* Model

Plexos® LP long-term optimization model, LT Plan®, served as the basis from which the I&M-specific capacity requirement evaluations were examined and recommendations were made. The LT Plan® model finds the optimal portfolio of future capacity and energy resources, including DSM additions that minimizes the cumulative present worth (CPW) of a planning entity's generation-related variable and fixed costs over a long-term planning horizon.

Plexos® LP accomplishes this by an objective function which seeks to minimize the aggregate of the following capital and production-related (energy) costs of the portfolio of resources:

- Fixed costs of capacity additions, *i.e.*, carrying charges on incremental capacity additions (based on an I&M-specific, weighted average cost of capital), and fixed O&M;
- Fixed costs of any capacity purchases;
- Program costs of (incremental) DSM alternatives;
- Variable costs associated with I&M's generating units. This includes fuel, start-up, consumables, market replacement cost of emission allowances, and/or carbon 'tax,' and variable O&M costs;
- Distributed, or customer-domiciled resources were effectively cost out at the equivalent of a full-retail "net metering" credit to those customers (*i.e.*, a "utility" perspective); and

- A 'netting' of the production revenue made into the PJM power market from I&M's generation resource sales *and* the cost of energy – based on unique load shapes from PJM purchases necessary to meet I&M's load obligation.

Plexos® executes the objective function described above while abiding by the following possible constraints:

- Minimum and maximum reserve margins;
- Resource addition and retirement candidates (i.e. maximum units built);
- Age and lifetime of generators;
- Retrofit dependencies (SCR and FGD combinations);
- Operation constraints such as ramp rates, minimum up/down times, capacity, heat rates, etc.;
- Fuel burn minimum and maximums;
- Emission limits on effluents such as SO_2 and NO_X; and
- Energy contract parameters such as energy and capacity.

The model inputs that compose the objective function and constraints are considered in the development of an integrated plan that best fits the utility system being analyzed. *Plexos*® does not develop a full regulatory cost-of-service (COS) profile. Rather, it typically considers only generation (G)-COS that changes from plan-to-plan, *not* fixed embedded costs associated with existing generating capacity and demand-side programs that would remain constant under any scenario. Likewise, transmission costs are included only to the extent that they are associated with new generating capacity, or are linked to specific supply alternatives. In other words, generic (nondescript or non-site-specific) capacity resource modeling would typically not incorporate significant capital spends for transmission interconnection costs.

B. Major Modeling Assumptions

(170 IAC 4-7-8(2))

1. Planning & Study Period

The economic evaluations of this planning process were carried out over a 2014-2033 planning period with discrete economic costs through 2040 and terminal "end-effects" thereafter.

2. Load & Demand Forecast

The internal load and peak demand forecast is based on the June 2013 load forecast.

3. Capacity Modeling Constraints

The major system limitations that were modeled by use of constraints are elaborated on below. The LT Plan®, LP optimization algorithm operates constraints in tandem with the objective function in order to yield the least-cost resource plan.

- Maintain a PJM-required minimum reserve margin of roughly 15.6% per year as represented earlier in this report on the I&M "going-in" capacity position chart.
- Under the terms of the NSR Consent Decree, I&M and AEP agreed to annual SO_2 and NO_X emission limits for the AEP-East fleet of 16 coal-fueled power plants in Indiana, Kentucky, Ohio, Virginia and West Virginia, inclusive of I&M-owned units.
- The restriction for consideration of new generation additions was assumed to not precede the PJM 2017/18 planning year given the typical minimal ~5-year

timeframe to approve, permit, design & engineer, procure materials, construct and commission new fossil generation resources.

There are many variants of available supply-side and demand-side resource options and types. It is a practical limitation that not all known resource types are made available as modeling options. A screening of available supply-side technologies was performed with the optimum assets made subsequently available as options. Such screens for supply alternatives were performed for each of the major duty cycle "families" (baseload, intermediate, and peaking).

The selected technology alternatives from this screening process do not necessarily represent the optimum technology choice for that duty-cycle family. Rather, they reflect proxies for modeling purposes.

Other factors will be considered that will determine the ultimate technology type (e.g., choices for peaking technologies: GE frame machines "E" or "F," GE LMS100 aeroderivative machines, etc.). The full list of screened supply options is included in Exhibit 3 of the Confidential Supplement.

Based on the established comparative economic screenings, the following specific supply alternatives were modeled in *Plexos*® for each designated duty cycle:

- *Peaking* capacity was modeled as blocks of seven, 86 MW GE-7EA Combustion Turbine units (summer rating of 78.5 MW x 7 = 550 MW), available beginning in 2017. Note: No more than one block could be selected by the model per year.

- *Intermediate* capacity was modeled as single natural gas Combined Cycle (2 x 1 GE-7FA with duct firing platform) units, each rated 618 MW (562 MW summer) available beginning in 2017.

In addition, beginning in the year 2020:

- *Plexos*® could select a 200 MW unit "uprate" at each of the Cook nuclear units.

- Wind resources were made available up to 100 MW annually of incremental nameplate capacity at a real (2013$) of $65/MWh

- Utility scale solar resources were available up to 50MW annually of incremental nameplate capacity according to the schedule in Figure 5D-3

- Distributed Generation resources were made available in approximately 10MW blocks of incremental capacity, annually, at full retail net metering rate.
- Energy Efficiency resources incremental to those included in the load forecast.

4. Commodity Pricing Scenarios

Three commodity pricing scenarios were developed by AEPSC to enable *Plexos*® to construct resource plans under various long-term pricing conditions. The long-term power sector suite of commodity forecasts are derived from the proprietary *Aurora*^{XMP}. *Aurora*^{XMP} is a long-term fundamental production-costing tool developed by EPIS, Inc., that is driven by user-defined input parameters, not necessarily past performance which many modeling techniques tend to utilize. For instance, unit-specific fuel delivery and emission forecasts established by AEP Fuel, Emissions and Logistics (FEL), are fed into *Aurora*^{XMP}. Likewise, capital costs and performance parameters for various new-build generating options, by duty-type, are vetted through AEP Engineering Services and incorporated in the tool. AEP uses *Aurora*^{XMP} to model the eastern synchronous interconnect as well as ERCOT. In this report, the three distinct long-term commodity pricing scenarios that were developed for *Plexos®* are: a "base" view or, "Fleet Transition2013 Base," a plausible "Fleet Transition 1H2013 Lower Band," and a plausible "Fleet Transition 1H2013 Higher Band." The scenarios are described below with the results shown in **Figure 8B-1**.

a. Fleet Transition 1H2013 Base

This case recognizes the vacatur of CSAPR by decision of the U. S. Court of Appeals. Consequently, certain emission allowance values prior to 2015 revert back to levels in line with continued administration of the Clean Air Interstate Rule pending the promulgation of a valid replacement. Assumptions include:

- MATS Rule effective date as proposed with compliance beginning in 2015;
- Initially lower natural gas price due to the emergence of shale gas plays; and
- CO_2 emission pricing begins in 2022.

The specific effect of the MATS Rule are modeled in the development of the long-term commodity forecast by retiring the smaller, older coal units which would not be economic to retrofit with emission control equipment. The retirement time frame modeled is 2015 through 2017. Those remaining coal generating units will have some combination of controls necessary to comply with the EPA's rules. Incremental regional capacity and reserve requirements will largely be addressed with new natural gas plants. One effect of the expected retirements or the emission control retrofit scenario, is an over-compliance of the previous CSAPR emission limits. This will drive the emission allowance price to zero by 2018 or 2019.

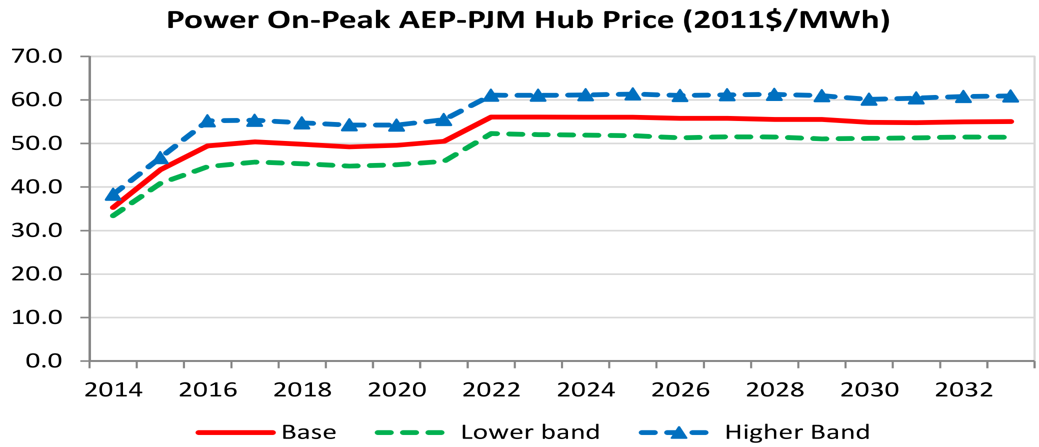
b. Fleet Transition 1H2013 Lower Band

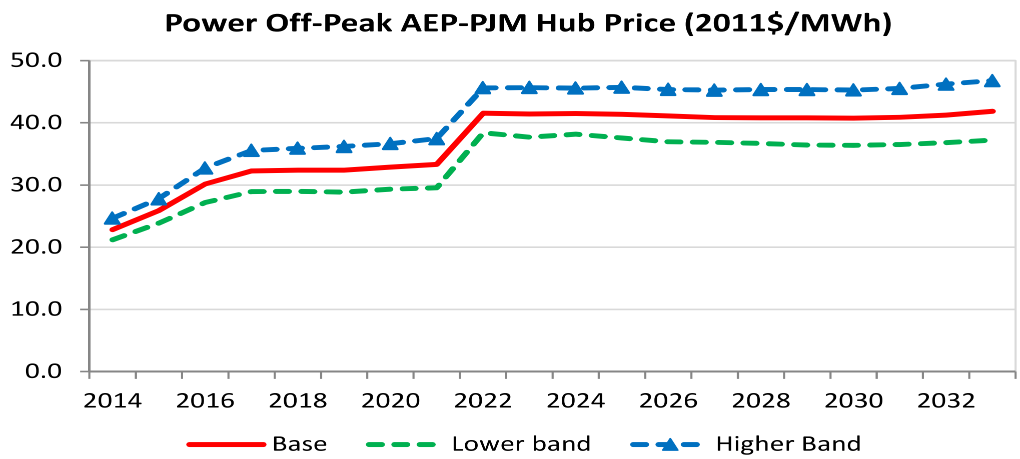
This case is best viewed as a plausible lower natural gas/energy price profile compared to the Fleet Transition 1H2013 Base. In the near term, Lower Band natural gas prices largely track the Base Case but, in the longer term, natural gas prices represent an even more significant infusion of shale gas. From a statistical perspective, this long-term pricing scenario is approximately one (negative) standard deviation from the Base Case and illustrates the effects of coal-to-gas substitution at plausibly lower gas prices. Like the Base Case scenario, CO_2 mitigation/pricing is assumed to start in 2022.

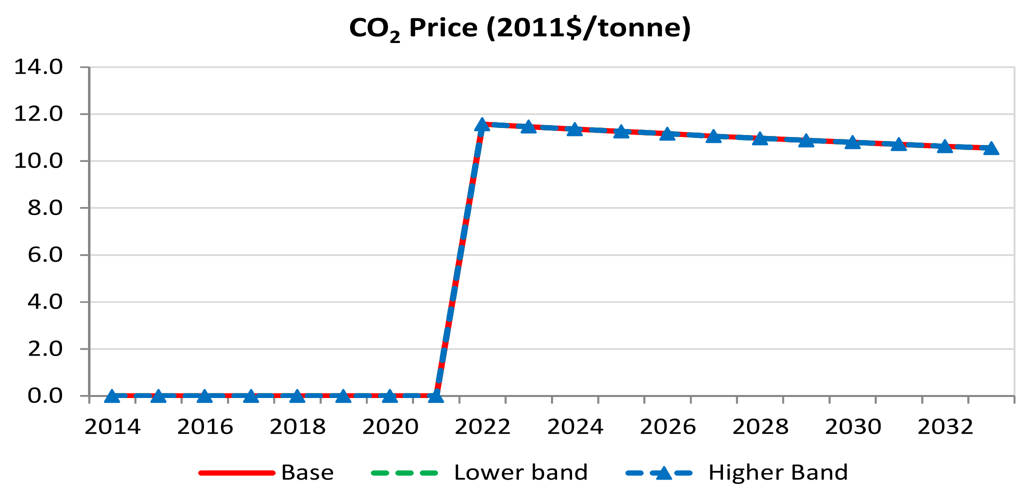
c. Fleet Transition 1H2013 Higher Band

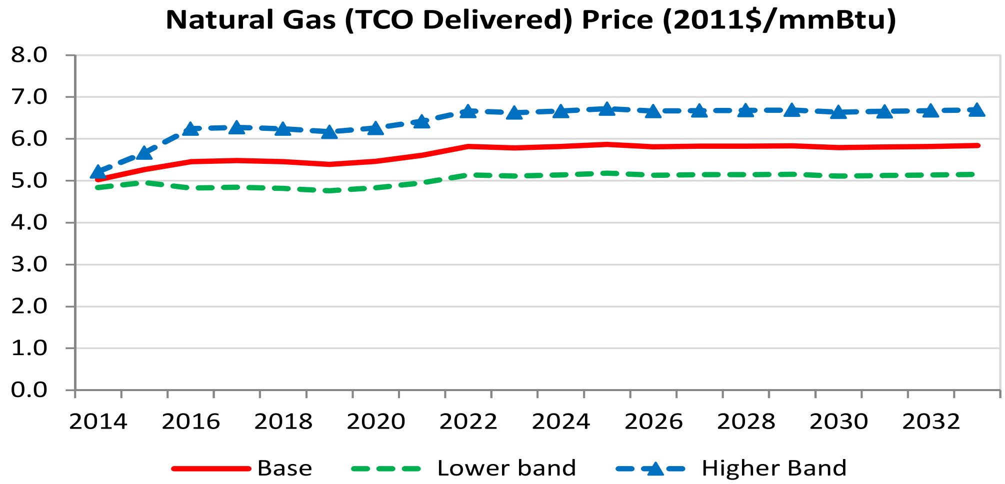
Alternatively, this Higher Band scenario offers a plausible, higher natural gas/energy price “sensitivity” to the Base Case scenario. Higher Band natural gas prices reflect certain impediments to shale gas developments including stalled technological advances (drilling and completion techniques) and as yet unseen environmental costs. The pace of environmental regulation implementation is in line with Fleet Transition and Lower Band. Analogous to the Lower Band scenario, this Higher Band view, from a statistical perspective, is approximately, one (positive) standard deviation from the Base Case. Also, like the Base Case and Lower Band scenarios, CO_2 pricing is assumed to begin in 2022.

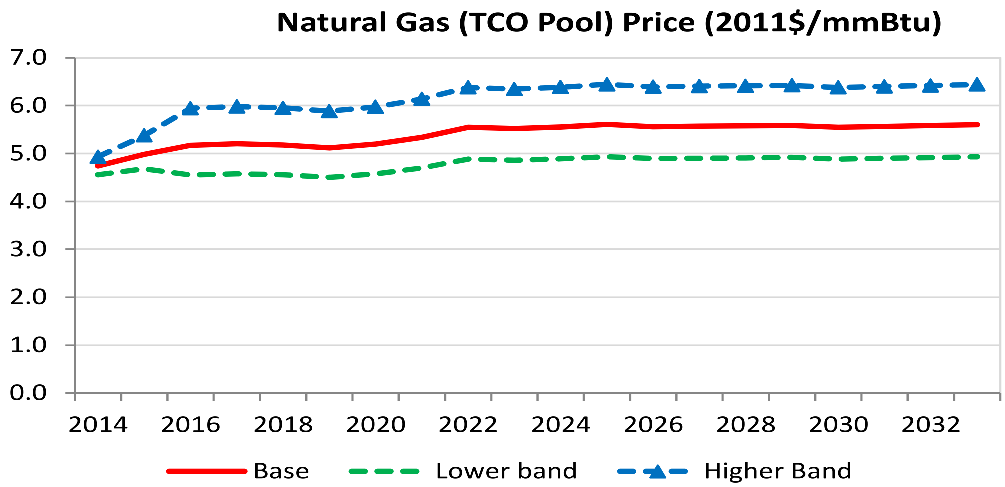
Figure 8B-1: Commodity Prices

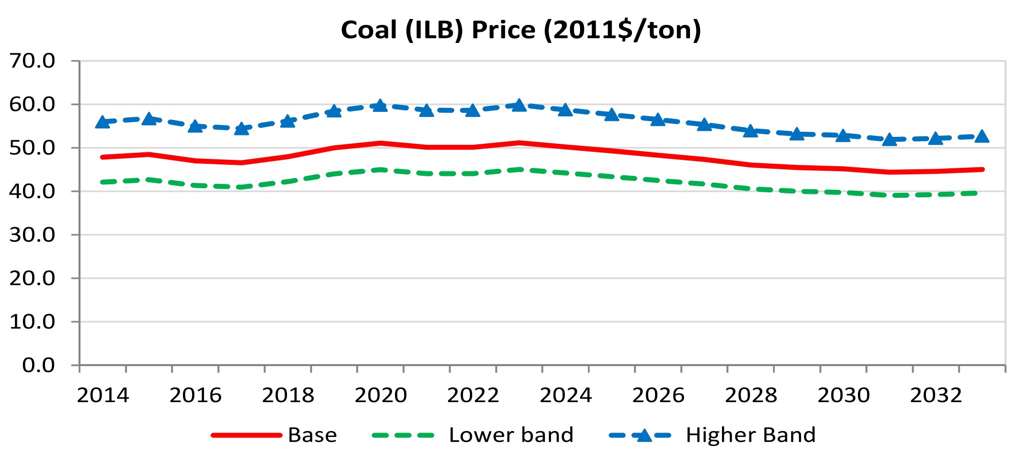


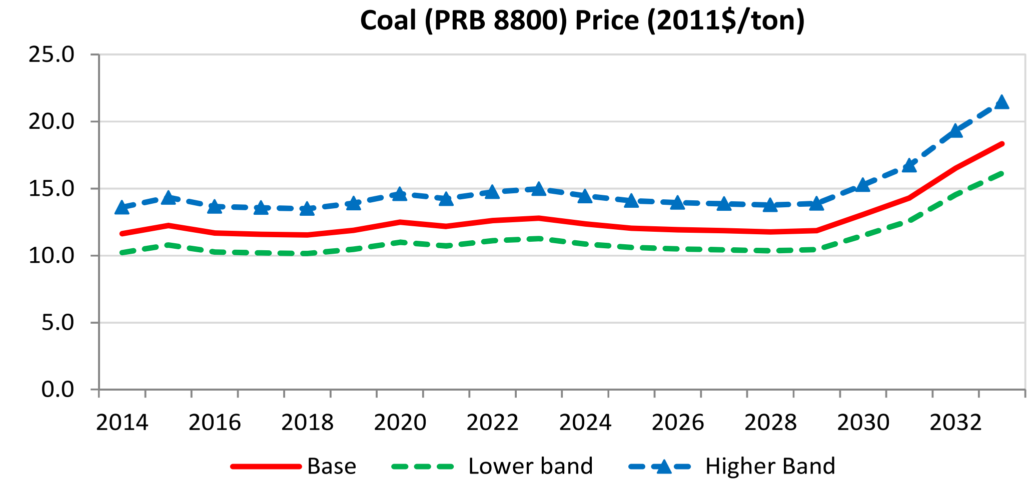


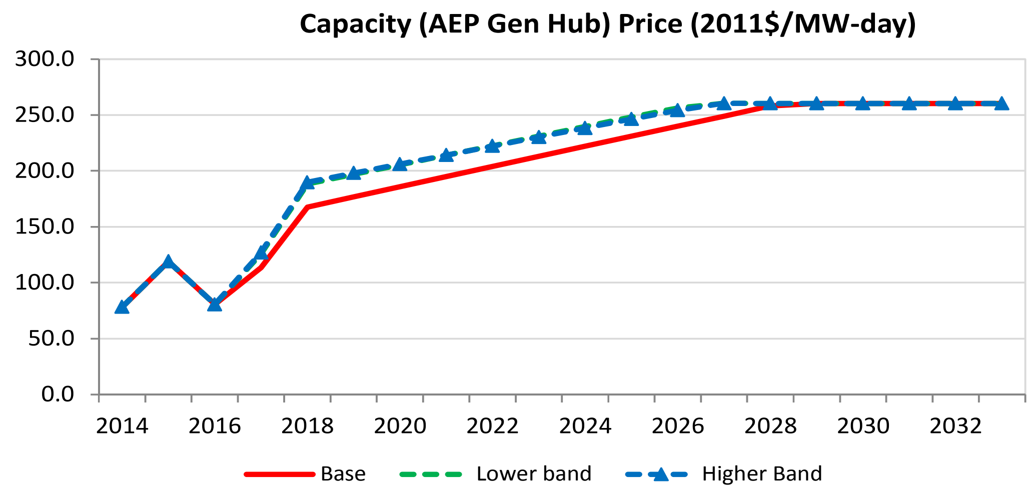



Natural Gas (TCO Delivered) Price (2011$/mmBtu)
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
Base
Lower band
Higher Band


Natural Gas (TCO Pool) Price (2011$/mmBtu)
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
Base
Lower band
Higher Band


Coal (ILB) Price (2011$/ton)
70.0
60.0
50.0
40.0
30.0
20.0
10.0
0.0
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
Base
Lower band
Higher Band





C. Modeling Results

(170 IAC 4-7-8(2) and 4-7-8(6))

1. Base Results by Pricing Scenario

Two *Plexos*®-derived portfolios were constructed; one utilizing the load forecast that stakeholders used to construct the eight portfolios presented in Chapter 2, and the updated forecast that serves as the basis for all analyses in this IRP. **Table 8C-1** shows the summary of capacity additions for the two *Plexos*®-optimized portfolios.

Table 8C-1

	Old Load Forecast	New Load Forecast
2014	Convert Tanner's Creek 4 to Gas	Retire Tanner's Creek 4
2019	Begin to add utility solar	
2020	Begin to add DSM	Begin to add DSM Begin to add utility solar
PJM (MW)		
DSM	249	249
Utility Solar	274	266
Natural Gas	500	0
Coal	(500)	(500)
Net Change by 2033	523	15

Portfolios consisting of the eight stakeholder portfolios as well as the two optimized portfolios constructed under the base commodity forecast and two different load forecasts (Old and New) were evaluated under the three commodity forecasts. The results are included in **Figure 8C-1** and **Table 8C-2**.

Figure 8C-1
Comparative CPWs of the Analyzed Portfolios By Commodity Pricing Scenarios

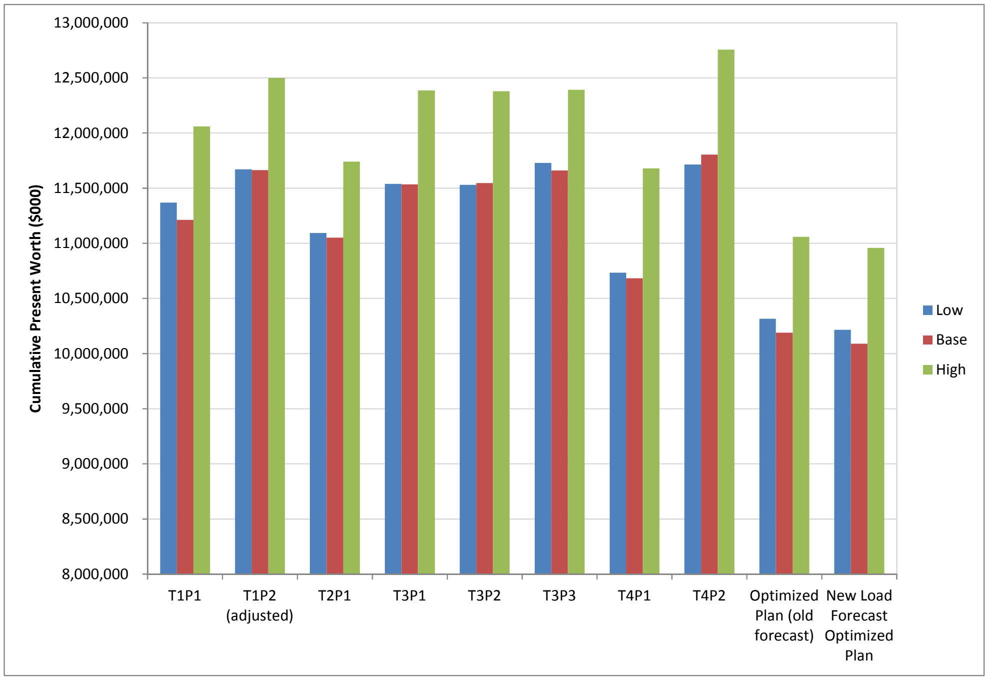


Table 8C-2
Data Table for Figure 8C-1 ($000)

	Low	Base	High
T1P1	11,369,124	11,213,442	12,058,872
T1P2 (adjusted)	11,671,498	11,664,197	12,500,334
T2P1	11,093,497	11,051,130	11,741,310
T3P1	11,538,342	11,535,897	12,384,925
T3P2	11,530,314	11,546,614	12,377,678
T3P3	11,728,759	11,660,238	12,392,685
T4P1	10,732,889	10,682,603	11,680,473
T4P2	11,714,020	11,803,021	12,755,540
Optimized Plan (old forecast)	10,316,774	10,189,998	11,058,788
New Load Forecast Optimized Plan	10,216,653	10,089,724	10,958,134

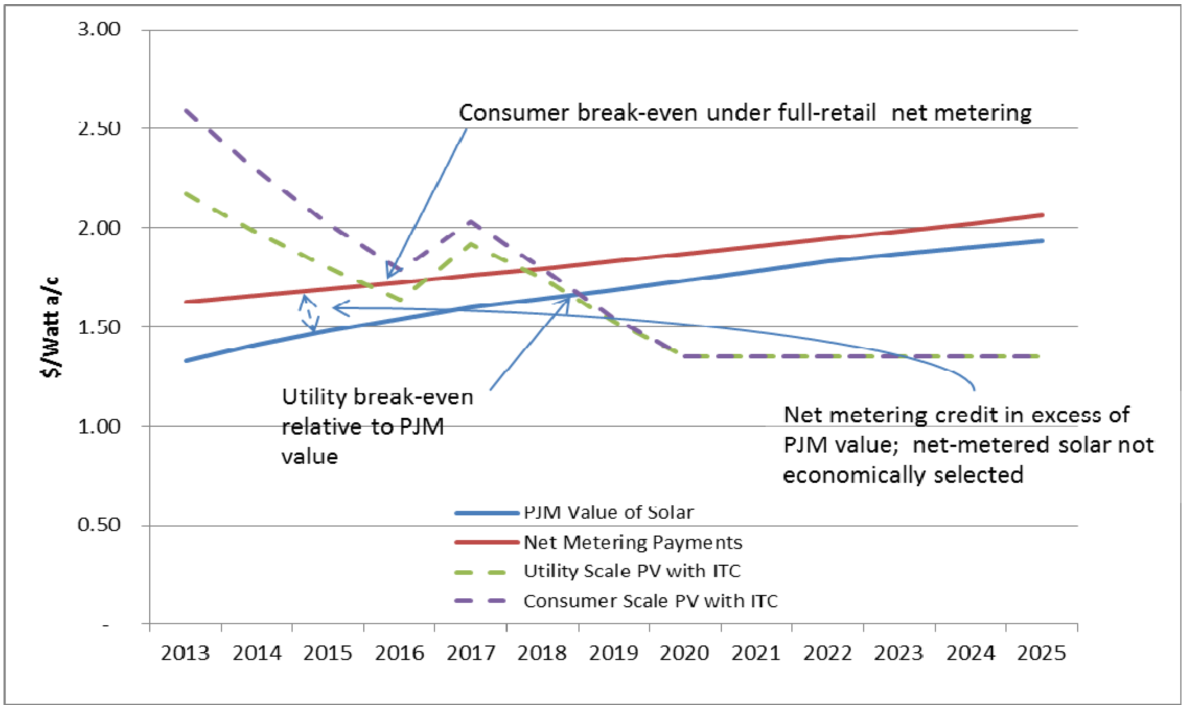
2. Observations: Needs Assessment

Some I&M-specific observations drawn from the initial *Plexos*® profiles reflected on **Exhibit 8-6** show that, from the PJM perspective, and with the exception of 2015 and 2016, I&M's capacity position is long for the forecast period.

3. Strategic Portfolio Creation & Evaluation

The Optimized Plan constructed under the new load forecast has the lowest cost under all commodity pricing scenarios. Distributed resources, and as modeled specifically, distributed solar resources did not optimize even though their costs decline throughout the forecast period. This is because, as described earlier, these distributed resources were modeled at their cost to the utility which is the full retail net metering rate not their installed capital costs. **Figure 8C-2** shows the avoided cost value of a typical rooftop PV resource in relation to its net metering cost.

Figure 8C-2



4. I&M Preferred Portfolio

Therefore, to address what is likely to occur, in terms of customer adoption of distributed solar resources, a final *"Preferred Portfolio"* was constructed with the portfolio optimized under the new load forecast as its basis. This Preferred Portfolio begins to add distributed solar in 2016 at a point that roughly corresponds to the cross-over point in value from the customer's perspective. By 2033, over 58 PJM MW (i.e., 153 MW nameplate) are added on the customer side. In summary, this portfolio is identical to the optimized portfolio with the addition of over 150 MW (nameplate) distributed generation through the planning period that is thought likely to occur under current net metering compensation rules.

5. I&M Additional Risk Analysis

(170 IAC 4-7-8(5) and 170 IAC 4-7-8(10)(A,B and C))

After the plans listed in Chapter 8C were constructed and modeled under the three discrete pricing scenarios, they were subjected to "stress testing" to ensure that none of the plans had outcomes that were deleterious under an array of input variables.

The eleven portfolios were further evaluated using a Monte Carlo technique where input variables are randomly selected from a universe of possible values, given certain constraints and relationships. This offers an additional approach by which to "test" these plans over a distributed range of certain key variables. The output is, in turn, a distribution of possible outcomes, providing insight as to the risk or probability of a high CPW relative to the expected outcome.

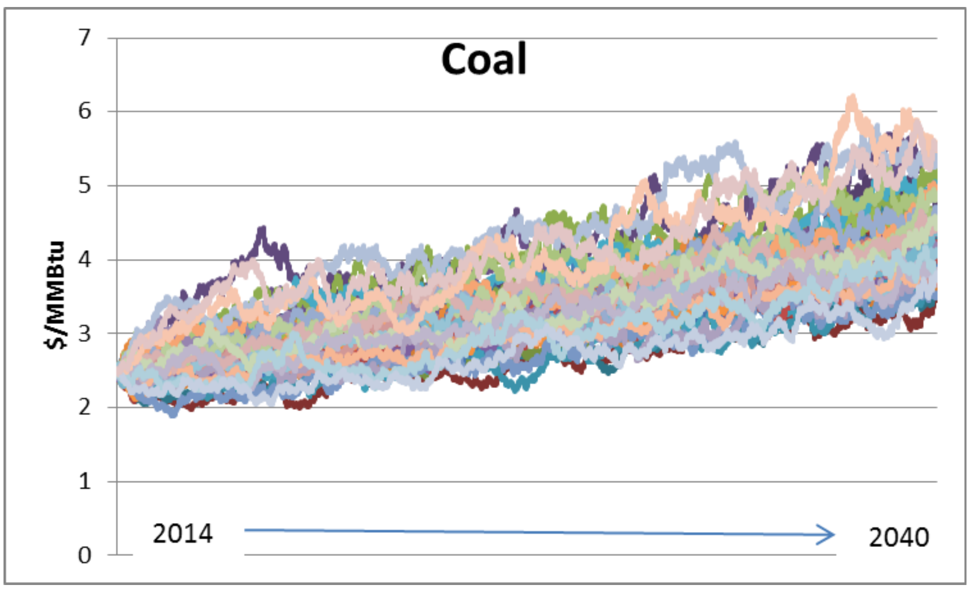
This study focused solely on the I&M portfolio of generating units. One-hundred risk iteration runs were performed with four risk factors being sampled. The results take the form of a distribution of possible revenue requirement outcomes for each plan. **Table 8C-3** shows the input variables or risk factors within this IRP analysis and their historical relationships to each other.

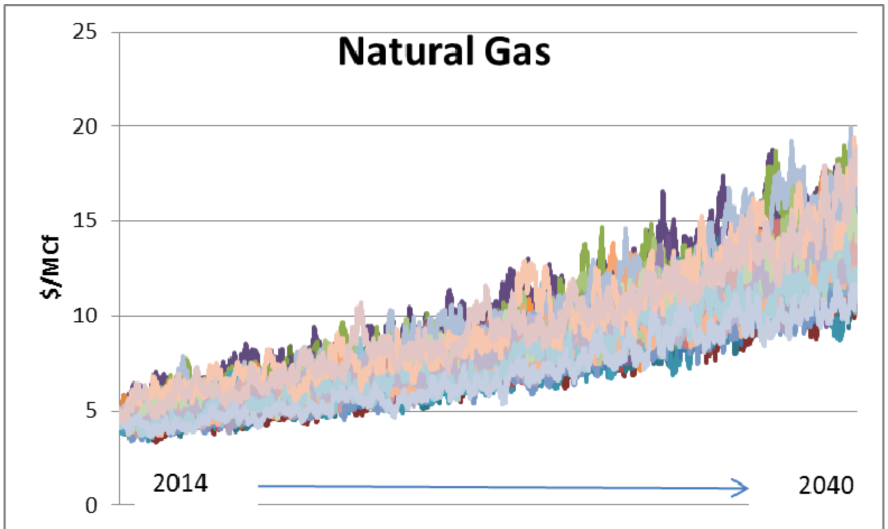
Table 8C-3
Risk Factors and their Relationships

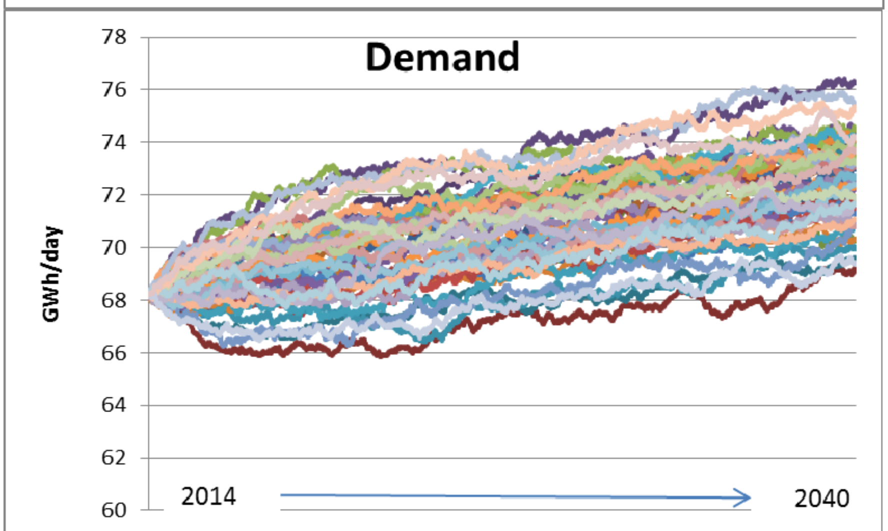
	Natural Gas	Coal	Power Prices	Demand
Natural Gas	1	0.18	0.47	0.08
Coal		1	0.53	-0.29
Power Prices			1	-0.19
Demand				1

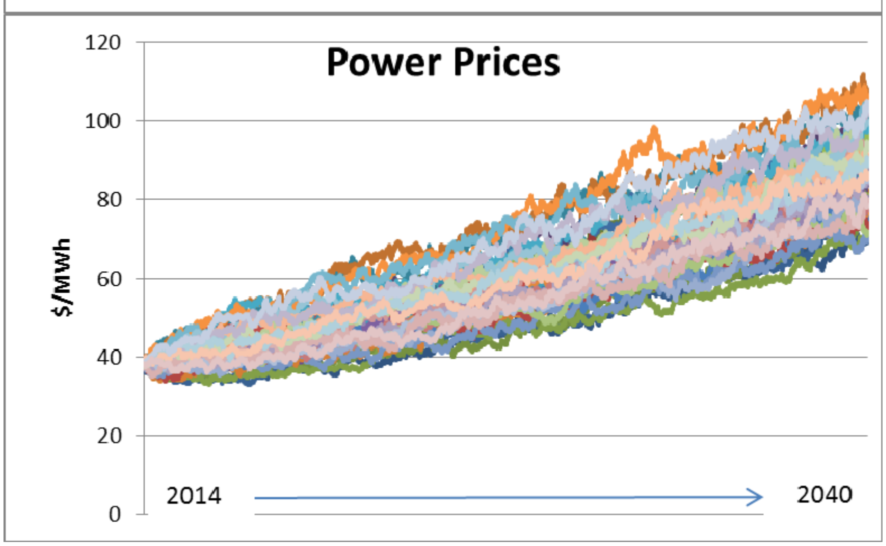
The variables inputs, and their range of possible (nominal) values over those 100 iterations are shown in **Figure 8C-3.**

Figure 8C-3
Variable Input Ranges




Natural Gas
$/MCf
25
20
15
10
5
0
2014
2040


Demand
GWh/day
78
76
74
72
70
68
66
64
62
60
2014
2040


Power Prices
$/MWh
120
100
80
60
40
20
0
2014
2040

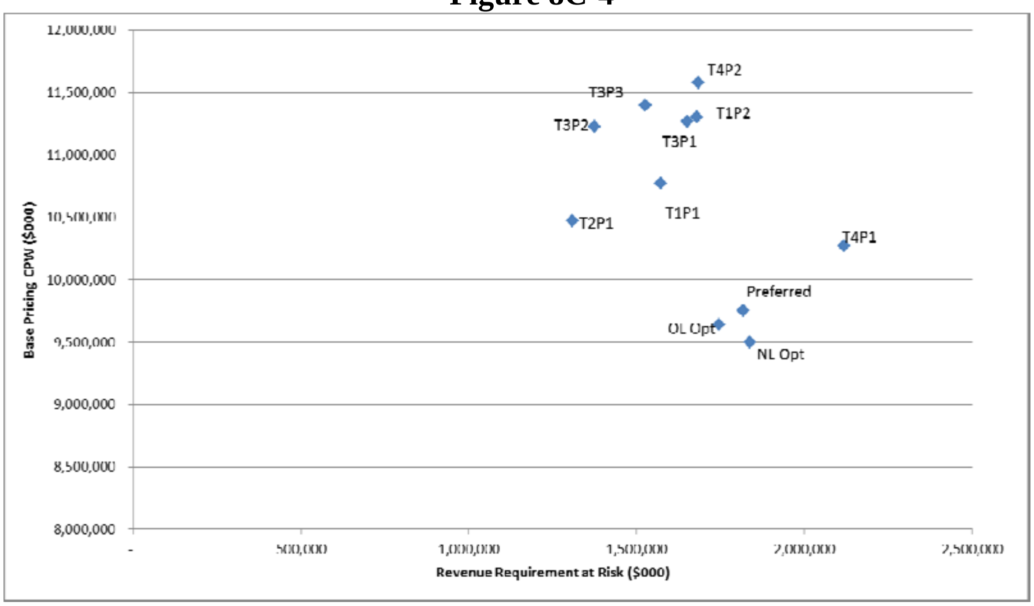
6. Modeling Process & Results & Sensitivity Analysis

(170 IAC 4-7-8(10)(B))

For each portfolio, the difference between its median and 95th percentile was identified as Revenue Requirement at Risk (RRaR). The 95th percentile is a level of required revenue sufficiently high that it will be exceeded, assuming the given plan is adopted, in five of the one-hundred simulations. Thus, it is 95% likely that those higher-end of revenue requirements would not be exceeded. The larger the RRaR, the greater the level of risk that customers would be subjected to adverse outcomes relative to the Base Case CPW.

Figure 8C-4 illustrates the RRaR and the expected value graphically.

Figure 8C-4



The differences in RRaR between the portfolios do not appear to be significant. A couple of points to note:

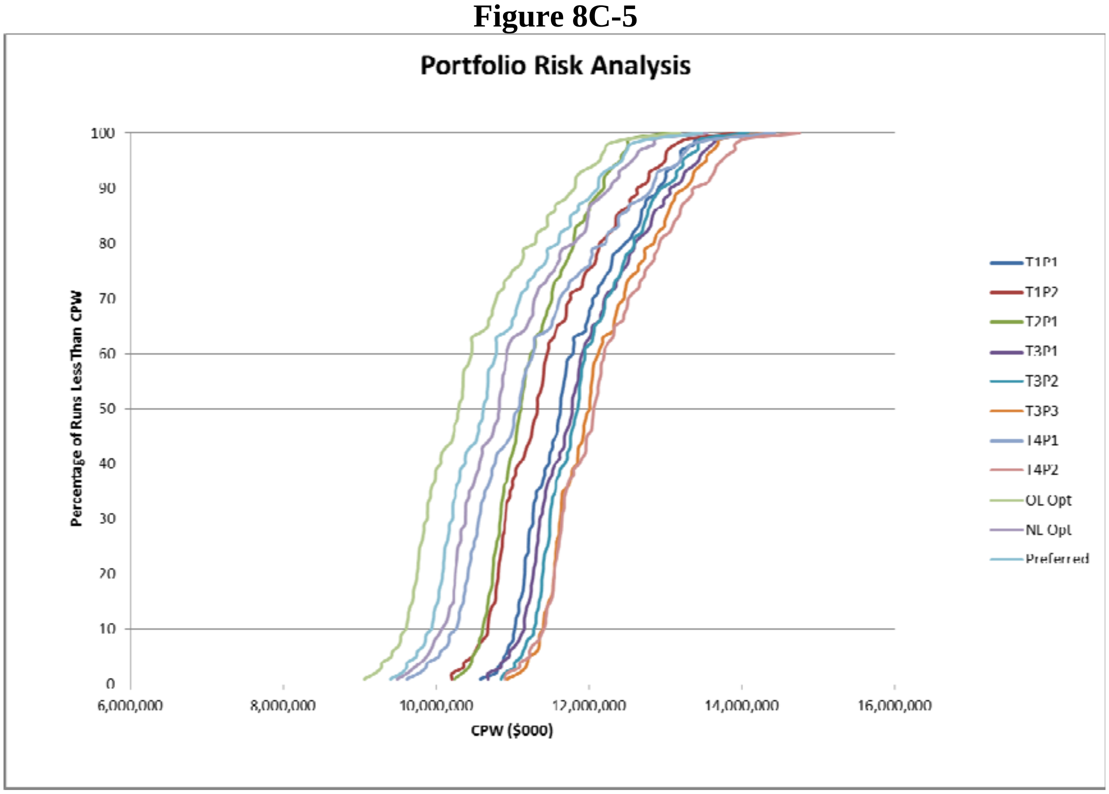
1. The addition of energy efficiency and solar generation, both distributed and

utility scale, work to reduce the risk or revenue requirement volatility. This is apparent by the reduction in RRaR associated with the two optimized portfolios and the Preferred Portfolio relative to the T4P1 portfolio.

2. The stakeholder portfolios that diversified fuel sources away from coal, either with gas, nuclear, renewables, or demand-side measures show diversification benefits as demonstrated by the portfolios that have both Rockport units having the higher risk.

However, it is critical to view the risk analysis in the context of the overall cost. The New load (NL) Optimized Portfolio, the portfolio with the lowest expected cost, has the lowest expected cost in 98 of 100 risk iterations. **Figure 8C-5** shows the CPW values for all 100 runs for each of the portfolios.

Figure 8C-5



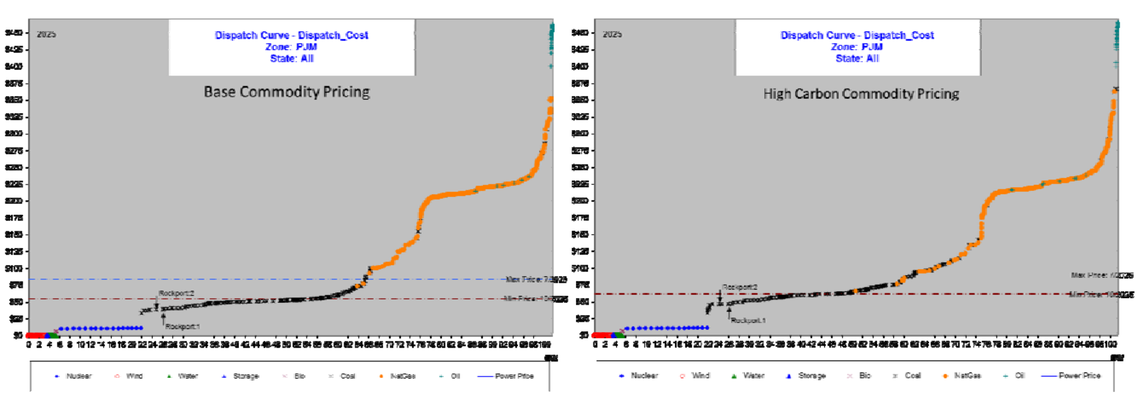
Based on the risk modeling performed, it is reasonable to conclude that the Preferred Portfolio represents a reasonable combination of expected costs and risk relative to the cost-risk profiles of the other portfolios.

7. Sensitivity to CO_2 Pricing

(170 IAC 4-7-8(10)(B))

All portfolios have been assessed under the assumption of a $15/metric ton cost for CO_2 beginning in 2022 and increasing with inflation thereafter, as explained in Chapter 8. To evaluate the impact that different assumptions for CO_2 costs would have, two separate optimizations were run on a suite of commodity prices associated with a zero carbon cost as well as a $25/metric ton cost In both cases, retrofitting the Rockport units remained the most economical solution. This result is consistent with a view of the available resources in the Eastern Interconnect under a base CO_2 and the high CO_2 cases. While the dispatch costs increase under a high CO_2 case, and additional coal units are retired in this area, the relatively efficient Rockport units remain viable as shown in Figure 8C-6.

Figure 8C-6



D. I&M Current Plan

(170 IAC 4-7-8(1))

The optimization results and associated risk modeling of this IRP show that, for I&M as a stand-alone entity in the PJM RTO, the Preferred Portfolio results in lower costs than the other portfolios while reflecting a level of distributed generation that is reasonable to expect will emerge under current cost assumptions and net metering arrangements. The following are some highlights of the "embedded" features of the Preferred Portfolio. **Exhibit 8-9** shows the summary table of the Preferred Plan.

- Retires Tanners Creek Plant (Unit 1-4) in 2015 effective with MATS Rule implementation.
- Adds environmental controls to Rockport Plant in 2015 to comply with EPA regulations for mercury and air toxins (*i.e.*, MATS Rule).
- Adds additional environmental controls (SCR) to Rockport Units 1 and 2 in 2017 and 2019, respectively, to reduce NO_x emissions.
- In 2025 and 2028, adds DFGD controls to Rockport Units 1 and 2, respectively, to further reduce SO_2 emissions allowing the units to continue operation through the planning period.
- Continues operation of the Cook Nuclear Plant through the planning period until mid-2030s.
- Implements Energy Efficiency programs so as to reduce energy requirements by 2,586 GWh (or 9.5% of projected energy needs) with a concomitant demand of 246 MW by 2033.

- Maintains demand response programs to reduce peak capacity requirements by 296 MW.
- Adds 200 MW (nameplate) of wind energy from the Headwaters Wind Farm in 2014, as well as an additional 100 MW in 2026.
- Beginning in 2020, I&M will add 50 MW (nameplate) of utility-scale solar capacity per year or 700 MW by 2033.
- Recognizes additional solar resources will be added by customers, starting in 2016 of approximately 10 MW and ramping up to over 150 MW by 2033.

Exhibit 8-8 provides the I&M expansion plan assuming I&M is a stand-alone member in PJM after 2014. I&M will satisfy its reserve margin requirements throughout the forecast period largely using a combination of existing capacity, renewable (wind and solar) additions, as well as (incremental) DSM.

E. IRP Summary

Inasmuch as there are many assumptions, each with its own degree of uncertainty, which had to be made in carrying out the resource evaluations, changes in these assumptions could result in modifications in the resource plan reflected for I&M. The resource plan presented in this IRP is sufficiently flexible to accommodate possible changes in key parameters, including load growth, environmental compliance assumptions, fuel costs, and construction cost estimates. As such, changes and assumptions are recognized, updated, and refined, with input information reevaluated and resource plans modified as appropriate.

This 2013 I&M IRP provides for reliable electric utility service, at reasonable cost, through a combination of existing resources, renewable energy and demand side programs. I&M will provide for adequate capacity and energy resources to serve its customers' peak demand, energy requirement and required PJM reserve margin needs throughout the forecast period.

F. Financial Effects

(170 IAC 4-7-8 (3)) and 170 IAC 4-7-8(8)(A, B, D and E))

The average "real" rate per kWh expected to be paid by I&M customers from 2013 to 2033 that results directly from the costs and energy consumption impacts associated with this plan is shown in **Figure 8F-1**. The Company, after receiving adequate rate relief, expects to be able to finance its utility plant additions with both internal and external funds at reasonable costs. As previously stated, I&M does not expect to add any major new baseload generation during the 2013-2023 period, however, environmental retrofit projects at Rockport in addition to life-cycle projects at the Cook Nuclear Plant will require significant investments.

Based on the load forecast in Section 3 and a discount rate of 7.92%, each difference in CPW between alternatives of $1,000,000,000 (one billion dollars) equates to approximately 0.4 ¢/kWh.

Figure 8F-1
Financial Effects

Revenue Requirements Preferred Plan		
Year	Nominal ($/kWh)	Real ($2014/kWh)
2014	$ 0.064	$ 0.064
2015	$ 0.065	$ 0.064
2016	$ 0.067	$ 0.065
2017	$ 0.064	$ 0.061
2018	$ 0.067	$ 0.062
2019	$ 0.070	$ 0.063
2020	$ 0.073	$ 0.065
2021	$ 0.074	$ 0.065
2022	$ 0.078	$ 0.066
2023	$ 0.076	$ 0.064
2024	$ 0.077	$ 0.063
2025	$ 0.078	$ 0.063
2026	$ 0.076	$ 0.060
2027	$ 0.078	$ 0.060
2028	$ 0.081	$ 0.061
2029	$ 0.076	$ 0.056
2030	$ 0.082	$ 0.060
2031	$ 0.085	$ 0.061
2032	$ 0.082	$ 0.058
2033	$ 0.083	$ 0.057

deflator = 2%

G. Exhibits 8-1 to 8-9

Exhibit 8-1

	AEP Gen Hub Capacity (2011$/MW-day)		
	Base	Lower band	Higher Band
2014	78.40	78.40	78.40
2015	119.10	119.10	119.10
2016	80.66	80.66	80.66
2017	113.52	125.84	127.03
2018	167.62	188.27	189.86
2019	176.81	196.93	198.05
2020	185.83	205.39	206.04
2021	194.93	213.94	214.13
2022	204.01	222.48	222.19
2023	213.09	231.01	230.27
2024	222.27	239.65	238.44
2025	231.22	248.05	246.37
2026	240.15	256.43	254.29
2027	249.07	260.45	260.45
2028	258.10	260.33	260.33
2029	260.33	260.33	260.33
2030	260.33	260.33	260.33
2031	260.33	260.33	260.33
2032	260.33	260.33	260.33
2033	260.33	260.33	260.33

Exhibit 8-2

TCO NG Delivered (2011$/mmBtu)

	Base	Lower band	Higher Band
2014	5.03	4.84	5.22
2015	5.26	4.96	5.67
2016	5.46	4.82	6.25
2017	5.48	4.85	6.28
2018	5.45	4.82	6.24
2019	5.39	4.76	6.17
2020	5.47	4.83	6.26
2021	5.61	4.95	6.42
2022	5.82	5.14	6.67
2023	5.78	5.11	6.63
2024	5.82	5.14	6.67
2025	5.87	5.18	6.72
2026	5.82	5.14	6.66
2027	5.82	5.14	6.68
2028	5.83	5.15	6.68
2029	5.83	5.15	6.69
2030	5.79	5.11	6.64
2031	5.81	5.13	6.66
2032	5.82	5.14	6.68
2033	5.84	5.16	6.70

TCO Pool (2011$/mmBtu)

	Base	Lower band	Higher Band
2014	4.74	4.56	4.93
2015	4.98	4.68	5.38
2016	5.17	4.55	5.95
2017	5.20	4.58	5.98
2018	5.18	4.56	5.95
2019	5.12	4.50	5.88
2020	5.20	4.57	5.97
2021	5.34	4.70	6.14
2022	5.55	4.88	6.38
2023	5.52	4.86	6.35
2024	5.55	4.89	6.39
2025	5.61	4.93	6.44
2026	5.56	4.89	6.39
2027	5.57	4.90	6.41
2028	5.58	4.91	6.41
2029	5.59	4.92	6.42
2030	5.55	4.88	6.38
2031	5.57	4.90	6.40
2032	5.58	4.91	6.42
2033	5.60	4.93	6.44

Exhibit 8-3

On Peak AEP_PJM Hub Price (2011$/MWh)

	Base	Lower band	Higher Band
2014	35.30	33.38	38.33
2015	43.91	40.84	46.72
2016	49.47	44.65	55.20
2017	50.35	45.72	55.32
2018	49.80	45.33	54.71
2019	49.24	44.77	54.23
2020	49.59	45.07	54.20
2021	50.52	45.89	55.49
2022	56.10	52.28	61.07
2023	56.09	52.01	61.06
2024	56.01	51.93	61.18
2025	55.99	51.79	61.36
2026	55.75	51.28	61.01
2027	55.75	51.54	61.18
2028	55.54	51.50	61.27
2029	55.50	51.03	60.95
2030	54.86	51.16	60.13
2031	54.76	51.31	60.45
2032	54.95	51.50	60.77
2033	55.04	51.41	60.89

Off Peak AEP_PJM Hub Price (2011$/MWh)

	Base	Lower band	Higher Band
2014	22.80	21.20	24.66
2015	25.89	23.86	27.77
2016	30.17	27.16	32.73
2017	32.26	28.94	35.55
2018	32.38	28.96	35.90
2019	32.37	28.84	36.19
2020	32.87	29.33	36.65
2021	33.33	29.53	37.45
2022	41.56	38.38	45.62
2023	41.40	37.70	45.65
2024	41.49	38.16	45.56
2025	41.35	37.54	45.69
2026	41.11	36.95	45.35
2027	40.84	36.87	45.25
2028	40.78	36.67	45.34
2029	40.77	36.42	45.34
2030	40.74	36.37	45.27
2031	40.86	36.49	45.51
2032	41.24	36.80	46.22
2033	41.83	37.20	46.79

Exhibit 8-4

	PRB 8800 (2011$/ton)		
	Base	Lower band	Higher Band
2014	11.63	10.23	13.61
2015	12.25	10.78	14.34
2016	11.68	10.28	13.66
2017	11.60	10.21	13.57
2018	11.54	10.16	13.50
2019	11.89	10.47	13.92
2020	12.49	10.99	14.61
2021	12.18	10.72	14.25
2022	12.62	11.10	14.76
2023	12.80	11.27	14.98
2024	12.35	10.87	14.45
2025	12.05	10.60	14.10
2026	11.93	10.50	13.96
2027	11.85	10.43	13.87
2028	11.77	10.36	13.78
2029	11.87	10.45	13.89
2030	13.06	11.49	15.28
2031	14.31	12.59	16.74
2032	16.52	14.54	19.33
2033	18.35	16.15	21.47

	ILB (2011$/ton)		
	Base	Lower band	Higher Band
2014	47.87	42.13	56.01
2015	48.52	42.70	56.77
2016	47.03	41.38	55.02
2017	46.57	40.98	54.49
2018	48.02	42.26	56.18
2019	50.02	44.02	58.52
2020	51.13	45.00	59.82
2021	50.15	44.13	58.67
2022	50.13	44.12	58.65
2023	51.19	45.05	59.90
2024	50.24	44.21	58.78
2025	49.32	43.40	57.70
2026	48.33	42.53	56.54
2027	47.36	41.67	55.41
2028	46.11	40.58	53.95
2029	45.50	40.04	53.23
2030	45.21	39.79	52.90
2031	44.41	39.08	51.96
2032	44.62	39.26	52.20
2033	45.07	39.66	52.74

Exhibit 8-5

	CO_2 (2011$/tonne)		
	Base	Lower band	Higher Band
2014	0.00	0.00	0.00
2015	0.00	0.00	0.00
2016	0.00	0.00	0.00
2017	0.00	0.00	0.00
2018	0.00	0.00	0.00
2019	0.00	0.00	0.00
2020	0.00	0.00	0.00
2021	0.00	0.00	0.00
2022	11.57	11.57	11.57
2023	11.46	11.46	11.46
2024	11.36	11.36	11.36
2025	11.26	11.26	11.26
2026	11.16	11.16	11.16
2027	11.06	11.06	11.06
2028	10.97	10.97	10.97
2029	10.88	10.88	10.88
2030	10.80	10.80	10.80
2031	10.72	10.72	10.72
2032	10.63	10.63	10.63
2033	10.55	10.55	10.55

Exhibit 8-6

Preferred Portfolio Energy (GWh)

	Distributed Solar	Rockport	TC1-3	TC4	Cook	EE	Utility Solar	Wind	OVEC	Hydro	Total
2014	-	13,774	617	2,218	17,168	-	-	1,102	753	109	35,740
2015	-	10,845	359	969	17,124	-	-	1,388	766	110	31,561
2016	14	13,392	-	-	16,137	-	-	1,392	856	110	31,900
2017	22	13,058	-	-	17,585	-	-	1,388	848	110	33,011
2018	30	12,125	-	-	17,506	-	-	1,388	853	110	32,011
2019	38	12,130	-	-	16,739	-	-	1,388	860	110	31,265
2020	46	10,262	-	-	17,635	77	76	1,392	850	110	30,449
2021	60	10,267	-	-	17,558	155	151	1,388	860	110	30,549
2022	74	9,467	-	-	16,871	232	227	1,388	860	110	29,229
2023	88	9,066	-	-	17,633	310	303	1,388	998	110	29,895
2024	102	9,529	-	-	17,558	387	380	1,392	998	110	30,456
2025	116	9,554	-	-	16,871	464	454	1,389	998	110	29,956
2026	130	12,879	-	-	17,633	542	530	1,674	998	110	34,495
2027	144	12,949	-	-	17,558	619	605	1,674	998	110	34,658
2028	159	13,125	-	-	16,871	722	684	1,679	998	110	34,347
2029	172	14,944	-	-	17,633	834	757	1,674	998	110	37,121
2030	186	14,908	-	-	17,558	924	832	1,674	998	110	37,191
2031	200	14,944	-	-	16,871	1,036	908	1,674	998	110	36,740
2032	215	14,576	-	-	17,633	1,139	988	1,679	998	110	37,338
2033	228	14,117	-	-	17,558	1,217	1,059	1,674	998	110	36,962

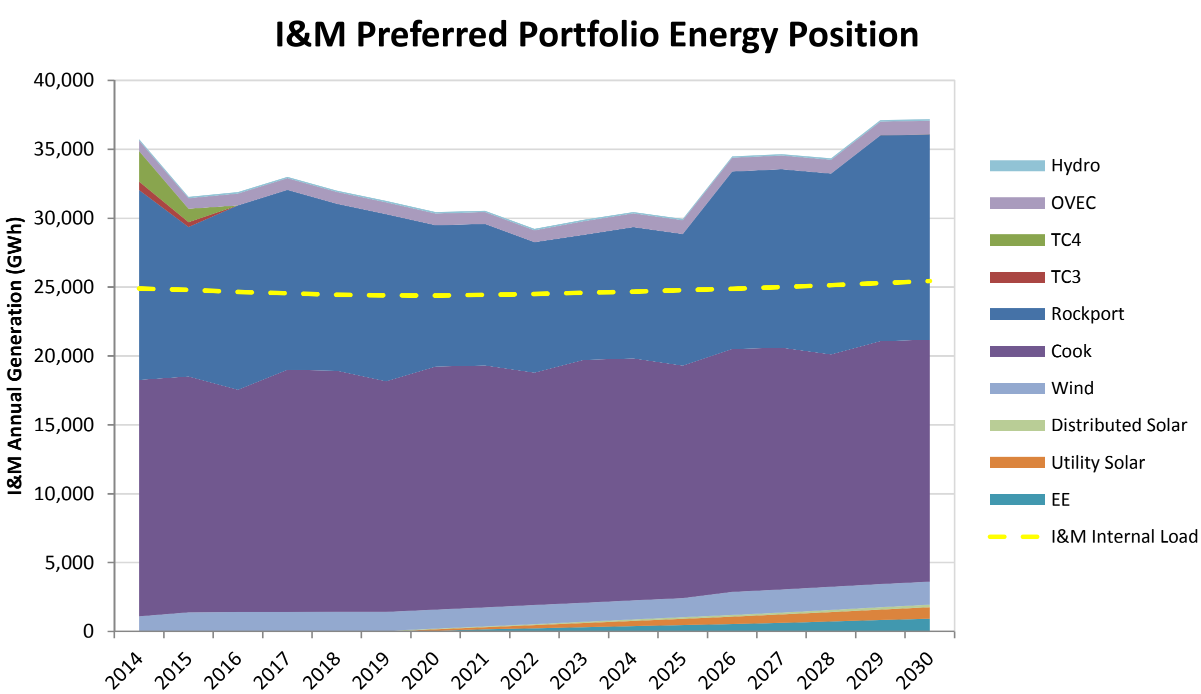


Exhibit 8-7

I&M PJM Capacity (UCAP)View (MW)

Going-In	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Coal	3,205	2,223	2,223	2,223	2,253	2,253	2,284	2,284	2,284	2,284	2,284	2,269	2,269	2,269	2,253	2,253	2,253	2,253	2,253	2,253
Nuclear	2,064	2,064	2,064	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114
Hydro	18	18	18	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
wind	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41	41
Utility Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distributed Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
EE	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PPA	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Total	5,494	4,512	4,512	4,555	4,585	4,585	4,616	4,616	4,616	4,616	4,616	4,601	4,601	4,601	4,585	4,585	4,585	4,585	4,585	4,585

Addition	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Coal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
wind	26	26	26	26	26	26	26	26	26	26	26	26	39	39	39	39	39	39	39	39
Utility Solar	0	0	0	0	0	0	19	38	57	76	95	114	133	152	171	190	209	228	247	266
Distributed Solar	0	0	4	6	8	10	12	15	19	22	26	29	33	36	40	44	47	51	54	58
Incremental EE	0	0	0	0	0	0	19	37	50	50	76	91	114	150	121	136	164	196	232	249
PPA	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	26	26	30	32	34	36	76	116	152	174	223	260	319	377	371	409	459	514	572	612

Total	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
Coal	3,205	2,223	2,223	2,223	2,253	2,253	2,284	2,284	2,284	2,284	2,284	2,269	2,269	2,269	2,253	2,253	2,253	2,253	2,253	2,253
Nuclear	2,064	2,064	2,064	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114	2,114
Hydro	18	18	18	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
wind	67	67	67	67	67	67	67	67	67	67	67	67	80	80	80	80	80	80	80	80
Utility Solar	0	0	0	0	0	0	19	38	57	76	95	114	133	152	171	190	209	228	247	266
Distributed Solar	0	0	4	6	8	10	12	15	19	22	26	29	33	36	40	44	47	51	54	58
EE	0	0	0	0	0	0	19	37	50	50	76	91	114	150	121	136	164	196	232	249
PPA	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166	166
Total	5,520	4,538	4,542	4,587	4,619	4,621	4,692	4,732	4,768	4,790	4,839	4,861	4,920	4,978	4,956	4,994	5,044	5,099	5,157	5,197

Exhibit 8-8

INDIANA MICHIGAN POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on (June 2013) Load Forecast
(2012/2013 - 2033/2034)
2013 (Going-In)

		Obligation to PJM										Resources								I&M Position (MW)	
		(1)	(2)	(3)	(4) =(1)+(3)	(5)	(6)	(7)	(8) =((4)-((5)*(6)))*(7)	(9)	(10) =(8)+(9)	(11)	(12)	(13)	(14)	(15)	(16) =(11)-(12) + Sum(14) +(15)	(17)	(18) =(16)*(1-(17))	(19) =((11)-(12) +(15)) *(1-(17)) -(10)	(20) =(18)-(10)
Planning Year		Internal Demand (a)	DSM (b)	Projected DSM Impact (c)	Net Internal Demand	Interruptible Demand Response (d)	Demand Response Factor	Forecast Pool Req't (e)	UCAP Obligation	Net UCAP Market Obligation (f)	Total UCAP Obligation	Existing Capacity & Planned Changes (g)	Net Capacity Sales (h)	Planned Capacity Additions: Units	Planned Capacity Additions: MW (i)	Annual Purchases	Net ICAP	AEP EFORd (j)	Available UCAP	Net Position w/o New Capacity	Net Position w/ New Capacity
2012 /13	(k)	4,217	(20)	0	4,217	246	0.954	1.087	4,329	0	4,329	5,487	231				5,256	5.99%	4,941	612	612
2013 /14	(k)	4,282	(31)	0	4,282	278	0.957	1.089	4,373	0	4,373	5,494	169				5,325	5.03%	5,057	684	684
2014 /15	(k)	4,348	(59)	0	4,348	305	0.956	1.089	4,417	0	4,417	5,500	0			26	5,526	7.46%	5,114	697	697
2015 /16	(k)	4,530	(92)	(8)	4,522	327	0.958	1.085	4,566	0	4,566	4,518	0	200 MW Wind	26	422	4,966	7.58%	4,590	0	24
2016 /17	(k)	4,453	(121)	(20)	4,433	355	0.955	1.090	4,464	0	4,464	4,518	0	Short Term Purchase		208	4,752	5.54%	4,489	0	25
2017 /18		4,237	(143)	(31)	4,206	296	0.955	1.090	4,277	0	4,277	4,561	(56)	9 MW Distributed Solar & Short Term Purchase		32	4,675	5.47%	4,419	118	142
2018 /19		4,243	(163)	(59)	4,183	296	0.955	1.090	4,253	0	4,253	4,591	(55)	5 MW Distributed Solar		34	4,706	5.48%	4,448	171	195
2019 /20		4,256	(180)	(92)	4,164	296	0.955	1.090	4,232	0	4,232	4,591	(60)	5 MW Distributed Solar		36	4,713	5.48%	4,455	198	223
2020 /21		4,264	(194)	(121)	4,143	296	0.955	1.090	4,209	0	4,209	4,622	(57)	5 MW Distributed Solar	13	79	4,797	5.47%	4,535	289	326
2021 /22		4,297	(205)	(143)	4,153	296	0.955	1.090	4,220	0	4,220	4,622	(46)	100 MW Wind & 55 MW Utility & Dist.Solar & 19 MW EE		122	4,829	5.47%	4,565	308	345
2022 /23		4,320	(214)	(163)	4,157	296	0.955	1.090	4,224	0	4,224	4,622	(32)	59 MW Utility & Distributed Solar & 18 MW EE		160	4,853	5.47%	4,588	326	364
2023 /24		4,341	(220)	(180)	4,161	296	0.955	1.090	4,228	0	4,228	4,622	0	59 MW Utility & Distributed Solar & 13 MW EE		182	4,843	5.47%	4,578	313	350
2024 /25		4,352	(224)	(194)	4,158	296	0.955	1.090	4,225	0	4,225	4,622	0	59 MW Utility & Distributed Solar		235	4,896	5.47%	4,628	366	403
2025 /26		4,388	(227)	(205)	4,182	296	0.955	1.090	4,251	0	4,251	4,607	0	59 MW Utility & Distributed Solar & 26 MW EE		274	4,920	5.20%	4,664	376	413
2026 /27		4,411	(228)	(214)	4,197	296	0.955	1.090	4,267	0	4,267	4,607	0	59 MW Utility & Distributed Solar & 15 MW EE		336	4,982	5.20%	4,723	419	456
2027 /28		4,437	(228)	(220)	4,216	296	0.955	1.090	4,289	0	4,289	4,607	0	59 MW Utility & Distributed Solar & 23 MW EE		400	5,046	5.20%	4,784	457	495
2028 /29		4,455	(227)	(224)	4,232	296	0.955	1.090	4,305	0	4,305	4,591	0	59 MW Utility & Distributed Solar & 36 MW EE		389	5,019	5.20%	4,758	416	453
2029 /30		4,491	(228)	(227)	4,264	296	0.955	1.090	4,340	0	4,340	4,591	0	59 MW Utility & Distributed Solar & (29) MW EE		429	5,059	5.20%	4,796	419	456
2030 /31		4,519	(228)	(228)	4,291	296	0.955	1.090	4,370	0	4,370	4,591	0	59 MW Utility & Distributed Solar & 15 MW EE		484	5,114	5.20%	4,848	441	478
2031 /32		4,548	(228)	(228)	4,320	296	0.955	1.090	4,402	0	4,402	4,591	0	59 MW Utility & Distributed Solar & 28 MW EE		543	5,173	5.20%	4,904	465	502
2032 /33		4,563	(227)	(227)	4,336	296	0.955	1.090	4,419	0	4,419	4,591	0	59 MW Utility & Distributed Solar & 32 MW EE		607	5,237	5.20%	4,965	509	546
2033 /34		4,602	(228)	(228)	4,374	296	0.955	1.090	4,460	0	4,460	4,591	0	59 MW Utility & Distributed Solar & 36 MW EE		649	5,279	5.20%	5,004	508	544

Notes:

(a) Based on (June 2013) Load Forecast (with implied PJM diversity factor)

(b) Existing plus approved and projected "Passive" EE, and IVV
(note: these values & timing are for reference only and are not reflected in position determination)

(c) For PJM planning purposes, the ultimate impact of new DSM is 'delayed' ~4 years to represent the ultimate recognition of these amounts through the PJM-originated load forecast process

(d) Demand Response approved by PJM in the prior planning year plus forecasted "Active" DR

(e) Installed Reserve Margin (IRM) = 15.6%(2012), 15.9%(2013-2014), 15.3%(2015), 15.6%(2016-2030)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes company MLR share of:
FRR view of obligations only

(g) Reflects the members ownership ratio of following summer capability assumptions:
AEP share of OVEC capacity (43.47% PPR-share of full ~2,180 total capacity)
Assumes hydro units are derated to August average output in 2017/18
Wind Farm PPAs (Where Applicable)

(g) continued
EFFICIENCY IMPROVEMENTS:
2018/19: Rockport 1: 36 MW (turbine)
2017/18: Cook 2: 50 MW (turbine)
2020/21: Rockport 2: 36 MW (turbine)
FGD DERATES:
2012/13: Clifty Creek 1-5: 2 MW each
2013/14: Clifty Creek 6: 2 MW
2025/26: Rockport 1: (18) MW
2028/29: Rockport 2: (18) MW
DSI DERATES:
2014/15: Rockport 1-2: 0 MW each
GAS CONVERSION RERATES:

RETIREMENTS:
2015/16: Tanners Ck. 1-3; Tanners Ck. 4 (Coal)
2035/36: Cook 1
2037/38: Cook 2

(h) Includes:
Includes company's MLR share of:
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA 2012/13 (171 MW)
Sale of 12 MW in 2012/13 and 13 MW in 2013/14 to Duke
Sale of 210 MW 2012/13 to EMMT
RPM Auction Sales 2012/13 - 2013/14 (646, 700)(MW UCAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

Estimated I&M nominations for PJM EE ('passive' DR program) levels
Plus: --reflected as a UCAP '<resource>'-- as part of PJM's emerging auction products (eff: 2014/15)

(i) New wind and solar capacity value is assumed to be 13% and 38% of nameplate

(j) Beginning 2008/09, based on 12-month avg. AEP EFORd in eCapacity as of twelve months ended 9/30 of the previous year

(k) Actual PJM forecast

(*) Combustion Turbines (CT) added to maintain Black Start capability

Effective 1-1-2014, remaining capacity that was previously MLR'd will be allocated as follows:

1) SEPA => 100% to APCo

Exhibit 8-9

Indiana Michigan Power Company
2013 Integrated Resource Plan
Cumulative Resource Changes (2014-2033)

Preferred Portfolio

IRP Yr.	PJM Plan Year[A]	(Cumulative) RETIREMENTS Coal	(Cumulative) 'PJM' ADDITIONS Coal Rerate	Nuclear Rerate	DSM (EE) Existing[D]	DSM (EE) New	Wind[E]	Solar[F] Utility-Scale	Solar[F] Distributed	Cumul. NET CHANGE	Resulting I&M Reserve Margin	(Cumulative) 'NAMEPLATE' ADDITIONS Wind	Solar Utility-Scale	Solar Distributed
		MW	MW	MW	MW	MW	MW	MW	MW	MW		MW	MW	MW
1	2014[B]	-	-	-	59	-	26	-	-	85	33.0% [B]	200	-	-
2	2015[B]	(982) [C]	-	-	92	-	26	-	-	(864)	6.7% [B]	200	-	-
3	2016[B]	(982)	-	-	121	-	26	-	4	(831)	11.5% [B]	200	-	9
4	2017	(982)	-	50	143	-	26	-	6	(757)	18.6%	200	-	15
5	2018	(982)	36	50	163	-	26	-	8	(699)	19.9%	200	-	20
6	2019	(982)	36	50	180	-	26	-	10	(680)	20.6%	200	-	25
7	2020	(982)	72	50	194	19	26	19	12	(590)	23.3%	200	50	31
8	2021	(982)	72	50	205	37	26	38	15	(539)	23.8%	200	100	40
9	2022	(982)	72	50	214	50	26	57	19	(494)	24.3%	200	150	49
10	2023	(982)	72	50	220	50	26	76	22	(466)	23.9%	200	200	59
11	2024	(982)	72	50	224	76	26	95	26	(413)	25.3%	200	250	68
12	2025	(982)	54	50	227	91	26	114	29	(391)	25.5%	200	300	77
13	2026	(982)	54	50	228	114	39	133	33	(331)	26.2%	300	350	87
14	2027	(982)	54	50	228	150	39	152	36	(273)	27.1%	300	400	96
15	2028	(982)	36	50	227	121	39	171	40	(298)	26.0%	300	450	105
16	2029	(982)	36	50	228	136	39	190	44	(259)	26.0%	300	500	115
17	2030	(982)	36	50	228	164	39	209	47	(209)	26.5%	300	550	124
18	2031	(982)	36	50	228	196	39	228	51	(154)	27.0%	300	600	133
19	2032	(982)	36	50	227	232	39	247	54	(97)	28.1%	300	650	142
20	2033	(982)	36	50	228	249	39	266	58	(56)	27.9%	300	700	152
					477 'TOTAL' DSM								*852 'TOTAL' Solar*	

(A) PJM Planning Year is effective 6/1/XXXX.

(B) I&M collectively-participated with affilated AEP-East operating companies in these established PJM (Capacity) Planning Years, electing the Fixed Resource Requirement (FRR) ('self'-)planning option through the 2016 PJM Planning Year. *For purposes of this IRP* only, beginning with the 2017 Planning Year I&M is assumed to be a 'stand-alone' entity.

(C) Tanners Creek Plant (Units 1-4) retirement effective approximately June 1, 2015, concurrent with implementation of U.S. EPA Mercury and Air Toxics Standards (MATS) Rules.

(D) Represents estimated contribution from current/known Indiana and Michigan program activity reflected in the Company's load and demand forecast.

(E) Due to the intermittency of wind resources, PJM initially recognizes 13% of wind resource 'nameplate' MW rating for ICAP determination purposes.

(E) Due to the intermittency of solar resources, PJM initially recognizes 38% of solar resource 'nameplate' MW rating for ICAP determination purposes.

9) Avoided Costs

(170 IAC 4-7-4(16))

A. Avoided Generation Capacity Cost

(170 IAC 4-7-4(16)(A); 4-7-6(b)(3); 4-7-8(C))

In the short term, the best representation of avoided capacity cost is the cost of purchasing capacity in the market. Market prices are expected to rise in time to approximately the cost of a new combustion turbine unit. The capacity costs in Exhibit 8-1, which are representative of the described costs, have been adjusted upward to represent a per-kW-of-load figure, including the impact of a change in load on losses and reserve requirements.

B. Avoided Transmission Capacity Cost

(170 IAC 4-7-4(16)(B)) and (170 IAC 4-7-6(a)(6)(D))

The transmission system is planned, constructed, and operated to serve not only the load physically connected to the Company's wires but also to operate adequately and reliably with interconnected systems.

The transmission system must have the capacity to reliably link generation resources with the various load centers and must be operated to provide this function even during forced and scheduled outages of critical transmission facilities. Conditions on neighboring systems and resulting parallel flows are other factors that also influence the capacity of the transmission system. Expansions of the transmission system are location specific and dependent upon the particular circumstances of load and connected generation at each location. Accordingly, unlike generation, the concept of transmission-related avoided cost is ever changing, based on the location being considered.

Because transmission expansion is so dependent upon location and factors beyond the Company's control, such as generation of others and conditions on interconnected systems, it is nearly impossible to determine a transmission-related avoided cost that has real meaning or is reliable for the Company other than on a case-by-case basis.

C. Avoided Distribution Capacity Cost

(170 IAC 4-7-4(16)(C))

The distribution system is planned, constructed, and operated to serve not only the load physically connected to I&M's wires, but also to operate adequately and reliably with generation and transmission connected to the distribution system.

The distribution system must have the capacity to reliably carry generation resources to various load centers and customers. Expansions of the distribution system are location-specific and dependent upon the particular circumstances of load, interconnected transmission, and connected generation at each location. Accordingly, unlike generation, the concept of distribution-related avoided cost is ever changing, based on the location being considered.

Because distribution expansion is so dependent upon location and factors beyond the Company's control, such as generation of others, local customer load changes and demand management, and local customer load diversity, it is nearly impossible to determine a distribution-related avoided cost that has real meaning or is reliable for the Company other than on a case-by-case basis.

D. Avoided Operating Cost

(170 IAC 4-7-4(16)(D) and 170 IAC 4-7-6-(a)(6)(D))

I&M's avoided operating cost including fuel, plant O&M, spinning reserve, and emission allowances, excluding transmission and distribution losses as discussed above, is provided in **Exhibit 9-2**, to the extent it is available. These data were developed using the *Plexos*® production cost model.

E. Exhibit 9-1

I&M - ESTIMATED "AVOIDED COSTS" OF ENERGY (cents/KWh)
FOR A 100-MW BLOCK OF COGENERATION PURCHASE
2014-33

	Peak	Off-Peak
2014	3.72	2.76
2015	4.84	2.85
2016	5.59	3.41
2017	5.83	3.74
2018	5.90	3.84
2019	5.97	3.92
2020	6.15	4.08
2021	6.40	4.22
2022	7.27	5.39
2023	7.43	5.49
2024	7.59	5.62
2025	7.75	5.72
2026	7.89	5.82
2027	8.06	5.91
2028	8.20	6.02
2029	8.37	6.15
2030	8.44	6.27
2031	8.60	6.42
2032	8.81	6.62
2033	9.02	6.85

Notes: A. The peak costing period is 0700 to 2300 local time Monday through Friday. All other hours comprise the off-peak costing period.
C. Energy costs are expressed in current-year dollars.

10) Short-Term Action Plan

(170 IAC 4-7-9)

The I&M Short-Term Action Plan applies to the period beginning November 2013 and ending December 2015. The I&M resource plan is regularly reviewed and modified as assumptions, scenarios, and sensitivities are examined and tested based upon new information that becomes available.

A. Current Supply-Side Commitments

Utilizing its adequate supply of diversely-fueled resources, supported by its participation in the Power Coordination and Bridge agreement, I&M expects to continue to provide its retail and wholesale customers with reliable electric service at a reasonable price by pursuing the following course of action:

- Continue to acquire wind resources, as needed to meet or correspond to Indiana renewable goals and Michigan renewable standards;
- Begin engineering and construction activities required to add pollution control equipment to Rockport Plant;
- Retire Tanners Creek units 1-4;
- Continue to implement and expand DSM programs;
- Continue with Cook LCM related activities.

B. Demand-Side Assessment

I&M's Short-Term Action Plan includes the continued monitoring and evaluation of DSM programs and continued enhancement of the DSM planning process. I&M plans to continue to assess cost-effective DSM opportunities that could potentially be offered. As further discussed in Chapter 4, I&M has in place a diverse selection of time-of-use rate options and other conservation-related tariffs / programs, including interruptible tariffs, designed to allow customers to achieve savings for taking actions which result in the more efficient use of electricity. See Demand Side Management programs, Chapter 4H, for a listing of I&M's tariffs that contain time-of-use, interruptible and demand response provisions. Included in this listing are the demand response riders approved by the IURC in 2011 in Cause No. 43566 PJM 1. These PJM-related riders are Emergency Demand Response (D.R.S. 1), Economic Demand Response (D.R.S. 2) and Ancillary Service Demand Response (D.R.S. 3). I&M will continue to offer tariffs that encourage its customers to make energy-efficient and cost saving decisions by participating in time-of-use, demand response, and interruptible load programs.

I&M currently has before the Indiana Commission in Cause No. 43827 DSM-3 a one-year DSM plan. **Table 10B-1** shows a summary of the DSM plan.

The 2014 Proposed Portfolio along with other Exhibits presented in Cause No. 43827 DSM-3, contain detailed descriptions of the programs including all cost-effectiveness tests. The breadth of DSM programs contained within the portfolio of addresses "lost opportunities" with the availability of "new construction" programs, as well as comprehensively addressing many sectors and facets of residential and commercial energy consumption.

Table 10B-1

	Budget	Annual kWh Savings	Annual kW Savings
Core Program			
Residential Lighting	1,545,042	16,542,202	17
Home Energy Audit	769,084	3,434,997	883
Income Qualified Weatherization	2,178,342	2,593,708	918
Energy Efficient Schools (Combined)	586,561	2,015,432	519
C&I Prescriptive	6,904,320	35,578,622	5,645
Core Program Total	11,983,348	60,164,961	7,983
Core Plus Program			
Residential Appliance Recycling	689,872	3,181,339	667
Residential Online Audit	338,585	735,892	189
Residential Home Energy Reports	553,275	7,517,350	1,930
Residential New Construction	206,931	236,432	77
Residential Weatherization	1,479,670	2,395,292	1,044
Residential Peak Reduction	1,694,201	-	2,656
Residential EE Products	757,736	2,293,183	531
C&I Custom	1,195,956	29,710,026	4,888
C&I Retro Commissioning Lite	1,425,732	28,489,293	4,692
C&I HVAC & Refrigeration	573,858	3,051,608	528
C&I Audit	636,362	6,501,040	778
Renewables & Demonstrations	275,613	24,420	8
Core Plus Program Total	9,827,791	84,135,874	17,989
EECO	2,250,000	8,468,581	1,671
Total I&M 2014 Program	24,061,139	152,769,415	27,642

I&M recognizes that there are a variety of methods available to effect demand and energy reductions, including utility-sponsored programs. The judicious deployment of cost-effective demand response tools such as time-of-day, seasonal, and interruptible tariffs to influence the peak use of electricity is a powerful method to incorporate into the IRP and can help delay the need for new supply side investment.

11) APPENDIX

Appendix A

A. 2013 Load Forecast Models and Input Data Sets

Indiana Michigan Power Company

Model Equations

Results of Statistical Tests and Input Data Sets

Pertaining to the 2013 Load Forecast

(PROVIDED ON CD)

Appendix B

B. Hourly Internal Loads for 2012

INDIANA MICHIGAN POWER COMPANY

HOURLY INTERNAL LOADS

2012

(PROVIDED ON CD)

Appendix C

C. Hourly Firm Load Lambdas for 2012

AEP SYSTEM / INDIANA MICHIAN POWER COMPANY

HOURLY FIRM-LOAD LAMDAS

2012

(Note: No longer available due to I&M's participation in PJM. AEP joined PJM effective 10-1-04)

Appendix D

D. I&M Existing Units

Plant Name	Unit Number	City or County	State	In-Service Year	Unit Type	Primary Fuel	Secondary Fuel	Ownership %	Winter Rating (MW)**	Summer Rating (MW)**	Environmental Controls	Notes
Cook Nuclear	1	Bridgman	MI	1975	ST	Nuclear	#N/A	100%	1,084	1,007	CL	As of 10-15-2013
Cook Nuclear	2	Bridgman	MI	1978	ST	Nuclear	#N/A	100%	1,107	1,057	CL	As of 10-15-2013
Rockport	1	Rockport	IN	1984	ST	Coal	#N/A	85% *	1,122	1,118	ACIESP, LNB, OFA	As of 10-15-2013
Rockport	2	Rockport	IN	1989	ST	Coal	#N/A	85% *	1,105	1,105	ACIESP, LNB, OFA	As of 10-15-2013
Tanners Creek	1	Lawrenceburg	IN	1951	ST	Coal	#N/A	100%	145	145	EP, LNB, SNCR	As of 10-15-2013
Tanners Creek	2	Lawrenceburg	IN	1952	ST	Coal	#N/A	100%	145	142	EP, LNB, SNCR	As of 10-15-2013
Tanners Creek	3	Lawrenceburg	IN	1954	ST	Coal	#N/A	100%	205	195	EP, LNB, SNCR	As of 10-15-2013
Tanners Creek	4	Lawrenceburg	IN	1964	ST	Coal	#N/A	100%	500	500	EP, LNB	As of 10-15-2013
Berrien Springs	1-12	Berrien Springs	MI	1908	HY	Water	#N/A	100%	5.2	3.1	#N/A	As of 10-15-2013
Buchanan	1-10	Buchanan	MI	1919	HY	Water	#N/A	100%	2.4	2.3	#N/A	As of 10-15-2013
Constantine	1-4	Constantine	MI	1921	HY	Water	#N/A	100%	0.8	0.5	#N/A	As of 10-15-2013
Elkhart	1-3	Elkhart	IN	1913	HY	Water	#N/A	100%	2.1	1.6	#N/A	As of 10-15-2013
Mottville	1-4	White Pigeon	MI	1923	HY	Water	#N/A	100%	0.9	0.6	#N/A	As of 10-15-2013
Twin Branch	1-8	Mishawaka	IN	1904	HY	Water	#N/A	100%	3.6	2.9	#N/A	As of 10-15-2013
									5,428	5,280		

* I&M Owns 50% plus purchases 70% of AEG's 50% shareof Rockport.

** Denotes 2013 Expected Seasonal Generation Capability

Appendix E

E. Portfolio Analysis Detail

Base	Fuel Costs	Load Cost	Emission Costs	(Incremental) Fixed & (All) Var Costs	(Incremental) Capital + DSM Program Costs	Less: Market Revenue / <Cost>	Total (All) Production and (Incremental) Fixed Costs	Less: Value / <Cost> of UCAP	Grand Total	Grand Total With End Effects	Grand Total without UCAP
T1P1	6,632,481	16,626,678	1,691,071	1,715,813	3,682,755	22,643,041	7,705,757	442,966	7,262,791	10,770,476	11,213,442
T1P2	7,283,890	16,250,891	774,065	1,611,455	4,937,026	22,115,286	8,742,040	1,541,491	7,200,549	10,435,721	11,977,212
T1P2 (adjusted)	5,014,538	16,250,891	557,575	1,293,059	4,052,940	19,003,242	8,165,762	360,525	7,805,236	11,303,672	11,664,197
T2P1	7,827,930	16,076,792	1,974,799	1,940,665	2,986,887	23,086,030	7,721,044	579,879	7,141,165	10,471,251	11,051,130
T3P1	5,420,032	16,118,771	557,529	1,381,786	3,547,138	19,256,131	7,769,124	265,898	7,503,226	11,269,999	11,535,897
T3P2	6,777,077	16,118,771	670,723	1,527,538	3,817,058	21,101,550	7,809,617	322,533	7,487,084	11,224,081	11,546,614
T3P3	6,687,314	16,497,682	1,861,513	1,860,197	2,797,429	21,869,599	7,834,537	260,809	7,573,728	11,399,429	11,660,238
T4P1	6,390,081	16,772,450	2,867,795	2,079,686	852,898	21,755,158	7,207,752	409,421	6,798,331	10,273,182	10,682,603
T4P2	6,777,077	16,675,820	670,723	1,527,538	3,153,378	20,854,361	7,950,175	223,210	7,726,965	11,579,811	11,803,021
Optimal Base Plan	6,390,081	16,772,450	2,867,795	2,079,686	1,448,716	22,454,024	7,104,704	692,067	6,412,637	9,497,931	10,189,998
New Load Forecast Optimal Plan	6,335,537	16,772,450	2,865,921	2,018,052	1,387,455	22,375,427	7,003,988	447,469	6,556,519	9,642,255	10,089,724
Preferred Plan	6,335,537	16,772,450	2,865,921	2,018,052	1,619,618	22,454,659	7,156,919	485,822	6,671,097	9,752,031	10,237,853
Low											
T1P1	6,044,339	15,565,093	1,537,301	1,716,117	3,682,755	20,574,721	7,970,884	484,938	7,485,946	10,884,185	11,369,124
T1P2	6,801,240	15,214,742	762,273	1,620,860	4,937,026	20,477,286	8,858,855	1,610,937	7,247,918	10,330,949	11,941,887
T1P2 (adjusted)	4,751,201	15,214,742	541,355	1,299,088	4,052,940	17,560,358	8,298,969	394,066	7,904,903	11,277,432	11,671,498
T2P1	7,113,381	15,052,734	1,782,471	1,938,766	2,986,887	20,984,831	7,889,407	684,313	7,205,094	10,409,184	11,093,497
T3P1	5,135,159	15,091,678	541,171	1,387,802	3,547,138	17,791,787	7,911,161	300,298	7,610,863	11,238,044	11,538,342
T3P2	6,357,046	15,091,678	656,406	1,535,082	3,817,058	19,512,437	7,944,834	358,777	7,586,056	11,171,537	11,530,314
T3P3	6,104,614	15,444,768	1,666,868	1,856,488	2,797,429	19,838,214	8,031,954	296,712	7,735,242	11,432,046	11,728,759
T4P1	5,729,288	15,701,007	2,535,080	2,071,211	852,898	19,527,655	7,361,828	452,478	6,909,350	10,280,410	10,732,889
T4P2	6,357,046	15,610,861	656,406	1,535,082	3,153,378	19,288,457	8,024,317	253,184	7,771,134	11,460,836	11,714,020
Optimal Base Plan	5,729,288	15,701,007	2,535,080	2,071,211	1,448,716	20,172,809	7,312,492	739,933	6,572,559	9,576,841	10,316,774
New Load Forecast Optimal Plan	5,668,174	15,701,007	2,532,626	2,009,392	1,387,455	20,086,526	7,212,129	475,655	6,736,473	9,740,997	10,216,653
Preferred Plan	5,668,174	15,701,007	2,532,626	2,009,392	1,619,618	20,159,518	7,371,299	514,901	6,856,398	9,858,451	10,373,352
High											
T1P1	7,092,581	18,533,813	1,706,800	1,703,157	3,682,755	24,610,461	8,108,646	485,458	7,623,189	11,573,415	12,058,872
T1P2	7,648,564	18,112,589	735,518	1,590,041	4,937,026	23,778,994	9,244,744	2,204,358	7,040,385	10,420,982	12,625,340
T1P2 (adjusted)	5,173,547	18,112,589	528,866	1,279,199	4,052,940	20,471,283	8,675,858	394,786	8,281,072	12,105,548	12,500,334
T2P1	8,490,073	17,917,707	2,068,469	1,929,070	2,986,887	25,222,969	8,169,237	684,226	7,485,011	11,057,085	11,741,310
T3P1	5,599,447	17,964,723	528,774	1,367,477	3,547,138	20,742,833	8,264,726	300,901	7,963,825	12,084,024	12,384,925
T3P2	7,076,844	17,964,723	636,657	1,508,460	3,817,058	22,699,629	8,304,113	359,244	7,944,869	12,018,434	12,377,678
T3P3	7,228,225	18,389,257	1,960,402	1,853,214	2,797,429	23,957,093	8,271,433	297,080	7,974,353	12,095,605	12,392,685
T4P1	6,962,709	18,697,162	3,021,460	2,075,615	852,898	23,835,212	7,774,631	453,108	7,321,523	11,227,365	11,680,473
T4P2	7,076,844	18,588,585	636,657	1,508,460	3,153,378	22,425,795	8,538,129	253,683	8,284,447	12,501,857	12,755,540
Optimal Base Plan	6,962,709	18,697,162	3,021,460	2,075,615	1,448,716	24,609,759	7,595,902	740,273	6,855,629	10,318,515	11,058,788
New Load Forecast Optimal Plan	6,919,019	18,697,162	3,020,222	2,014,178	1,387,455	24,543,760	7,494,277	475,537	7,018,740	10,482,597	10,958,134
Preferred Plan	6,919,019	18,697,162	3,020,222	2,014,178	1,619,618	24,631,510	7,638,690	514,757	7,123,933	10,577,477	11,092,234

Appendix F

F. Exhibit 11-1: I&M Projected SO_2, NO_x, Hg & CO_2 Emissions and Ash Production

Indiana Michigan Power Company
Projected SO_2, NO_x, Hg & CO_2 Emissions and Ash Production
2014 - 2033

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
SO_2 Emissions (1000 Tons)																				
Rockport 1	23.1	9.9	11.6	9.9	11.0	10.3	8.8	9.4	5.9	5.9	6.0	4.4	3.6	3.6	3.8	3.7	3.7	3.9	3.6	3.4
Rockport 2	18.6	8.7	10.3	11.4	10.4	9.4	9.6	9.0	6.8	5.9	7.1	6.5	11.0	11.3	7.9	4.0	4.0	4.0	3.6	3.7
Plant Total	41.6	18.6	21.9	21.3	21.4	19.6	18.4	18.4	12.6	11.8	13.1	10.9	14.6	15.0	11.8	7.7	7.6	7.8	7.2	7.1
Tanners Creek 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tanners Creek 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tanners Creek 3	4.7	2.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tanners Creek 4	12.1	4.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Plant Total	16.8	6.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NO_x Emissions (1000 Tons)																				
Rockport 1	5.8	4.2	6.4	5.5	1.2	1.1	0.9	1.0	0.6	0.6	0.6	0.5	1.1	1.1	1.2	1.1	1.1	1.2	1.1	1.1
Rockport 2	4.8	4.8	6.1	6.4	5.8	5.2	1.1	1.0	0.7	0.6	0.8	0.7	1.2	1.2	0.9	1.3	1.2	1.2	1.1	1.2
Plant Total	10.6	9.0	12.5	11.9	7.0	6.4	2.0	2.0	1.4	1.3	1.4	1.2	2.3	2.4	2.1	2.4	2.4	2.4	2.2	2.2
Tanners Creek 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tanners Creek 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tanners Creek 3	1.1	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tanners Creek 4	1.8	0.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Plant Total	2.9	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hg (lbs)																				
Rockport 1	186.0	77.4	83.9	71.6	79.6	74.3	63.5	67.7	42.3	42.6	43.4	31.8	74.4	75.0	78.9	75.4	76.1	79.9	74.9	70.3
Rockport 2	149.6	63.8	79.7	83.6	76.1	68.8	70.7	66.5	49.8	43.5	52.0	47.8	80.6	83.2	58.3	83.5	81.6	82.1	74.3	76.9
Plant Total	335.7	141.2	163.6	155.2	155.7	143.1	134.2	134.2	92.1	86.1	95.5	79.6	154.9	158.2	137.2	158.9	157.7	162.0	149.2	147.1
Tanners Creek 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tanners Creek 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tanners Creek 3	3.0	1.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tanners Creek 4	71.8	8.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Plant Total	74.8	9.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
CO_2 (1000 Tons)																				
Rockport 1	6,791.9	4,901.1	7,401.1	6,320.4	7,053.3	6,578.8	5,625.5	6,000.8	3,746.2	3,776.6	3,847.7	2,817.8	6,587.6	6,639.8	6,987.5	6,679.9	6,744.1	7,075.9	6,635.6	6,222.7
Rockport 2	5,611.3	5,629.0	7,032.0	7,372.7	6,711.8	6,069.9	6,263.6	5,886.0	4,407.3	3,852.5	4,609.4	4,232.3	7,135.2	7,370.9	5,166.0	7,396.3	7,228.4	7,271.5	6,577.4	6,810.2
Plant Total	12,403.1	10,530.1	14,433.1	13,693.1	13,765.1	12,648.7	11,889.1	11,886.8	8,153.6	7,629.1	8,457.1	7,050.1	13,722.8	14,010.8	12,153.6	14,076.2	13,972.5	14,347.5	13,213.0	13,032.9
Tanners Creek 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tanners Creek 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tanners Creek 3	872.8	436.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tanners Creek 4	1,797.7	735.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Plant Total	2,670.5	1,171.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Ash Production (1000 Tons)																				
Rockport 1	190.1	135.6	204.4	174.6	194.1	181.1	155.0	165.4	103.4	104.2	106.1	77.7	250.8	252.8	265.9	254.2	256.7	269.2	252.7	237.0
Rockport 2	157.1	155.7	194.3	203.6	185.4	167.7	172.5	162.2	121.6	106.4	127.1	116.7	196.2	202.7	142.1	281.4	275.1	276.7	250.3	259.2
Plant Total	347.2	291.3	398.7	378.2	379.5	348.8	327.5	327.5	225.0	210.6	233.2	194.5	447.1	455.5	408.0	535.6	531.8	545.9	502.9	496.3
Tanners Creek 1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tanners Creek 2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tanners Creek 3	36.6	18.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Tanners Creek 4	46.6	19.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Plant Total	83.2	37.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Note: Rockport is based on I&M portion only (85% Unit 1 & 85% of Unit 2).
Rockport 1 is utilizing a blend of 87% PRB coal and 13% Eastern coal from 2014-25, and from 2026-33 it is utilizing a blend of 20% PRB coal and 80% ILB coal
Rockport 2 is utilizing a blend of 87% PRB coal and 13% Eastern coal from 2014-28, and from 2029-33 it is utilizing a blend of 20% PRB coal and 80% ILB coal
Tanners Creek 1-3 units are utilizing 100% Eastern coal from 2014-33
Tanners Creek 4 is utilizing a blend of 80% PRB coal and 20% Eastern coal from 2014-33

Appendix G

G. Cross-Reference Table – Current Rule

Cross Reference Table

Current IRP Rule Requirements	**Report Reference**
170 IAC 4-7-4 Methodology and documentation requirements	
Sec. 4. An IRP covering at least a twenty (20) year future period prepared by a utility must include a discussion of the methods, models, data, assumptions, and definitions used in developing the IRP and the goals and objectives of the plan. The following information must be included:	
(1) The data sets, including data sources, used to establish base and alternative forecasts. A third party data source may be presented in the form of a reference. The reference must include the source title, author, publishing address, date and page number of relevant data. The data sets must include an explanation for adjustments. The data must be provided on electronic media and hard copy, or as specified by the commission.	Chapter 3.K.- Data Sources, Chapter 11 - Appendix A and Confidential Exhibits 4 and 5
(2) A description of the utility's effort to develop and maintain, by customer class, rate class, SIC code, and end-use, a data base of electricity consumption patterns. The data base may be developed using, but not limited to, the following methods:	Chapter 3.M.- Customer Surveys
(A) Load research developed by the individual utility.	Chapter 3.J. - Historical and Projected Load Profiles and Chapter 3.N - Load Research Class Interval Usage Methodolgy
(B) Load research developed in conjunction with another utility.	Not Applicable
(C) Load research developed by another utility and modified to meet the characteristics of that utility.	Not Applicable
(D) Engineering estimates.	Chapter 3.C.3. - Long-term Forecasting Models
(E) Load data developed by a non-utility source.	Chapter 3.C.3. - Long-term Forecasting Models
(3) A proposed schedule for industrial, commercial, and residential customer surveys to obtain data on end-use appliance penetration, end-use saturation rates, and end-use electricity consumption patterns.	Chapter 3.M.- Customer Surveys
(4) A discussion of customer self-generation within the service territory and the potential effects on generation, transmission, and distribution planning and load forecasting.	Chapter 3.O. - Customer Self-Generation
(5) A description of model structure and an evaluation of model performance.	Chapter 3, Sections C, D, & H.; also Confidential Exhibit 4
(6) A complete discussion of the alternative forecast scenarios developed and analyzed, including a justification of the assumptions and modeling variables used in each scenario.	Chapter 3.G. - Forecast Uncertainty and Range of Forecasts
(7) A description of the fuel inventory and procurement planning practices, including the rationale, used in the development of the utility's integrated resource plan.	Chapter 5.C. - Fuel Inventory and Procurement Practices
(8) A description of the SO_2 emission allowance inventory and procurement planning practices, including the rationale, used in the development of the utility's integrated resource plan.	Chapter 6 - Environmental Compliance

Cross Reference Table

Current IRP Rule Requirements	**Report Reference**
(10) A regional, or at a minimum, Indiana specific power flow study prepared by a regional or subregional organization. This requirement may be met by submitting Federal Energy Regulatory Commission (FERC) Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993. The power flow study shall include the following:	Chapter 7.B. and FERC 715 (Confidential Exhibit 3)
(A) Solved real flows.	Chapter 7.B. and FERC 715 (Confidential Exhibit 3)
(B) Solved reactive flows.	Chapter 7.B. and FERC 715 (Confidential Exhibit 3)
(C) Voltages.	Chapter 7.B. and FERC 715 (Confidential Exhibit 3)
(D) Detailed assumptions.	Chapter 7.B. and FERC 715 (Confidential Exhibit 3)
(E) Brief description of the model(s).	Chapter 7.B. and FERC 715 (Confidential Exhibit 3)
(F) Glossary of terms with cross references to the names of buses and line terminals.	Chapter 7.B. and FERC 715 (Confidential Exhibit 3)
(G) Sensitivity analysis, including, but not limited to, the forecast of the following:	Chapter 7.B. and FERC 715 (Confidential Exhibit 3)
(i) Summer and winter peak conditions.	Chapter 7.B. and FERC 715 (Confidential Exhibit 3)
(ii) Light Load as well as heavy transfer conditions for one (1), two (2), five (5), and ten (10) years out.	Chapter 7.B. and FERC 715 (Confidential Exhibit 3)
(iii) Branch circuit ratings, including, but not limited to, normal, long term, short term, and emergency.	Chapter 7.B. and FERC 715 (Confidential Exhibit 3)
(11) Any recent dynamic stability study prepared for the utility or by the utility. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993.	Chapter 7.B. and FERC 715 (Confidential Exhibit 3)
(12) Applicable transmission maps. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993.	Chapter 7.A., Conf. Exhibit 6 and FERC-715 (Conf. Exhibit 4)
(13) A description of reliability criteria for transmission planning as well as the assessment practice used. This requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993.	Chapter 7.B. and FERC 715 (Confidential Exhibit 3)
(14) An evaluation of the reliability criteria in relation to present performance and the expected performance of the utility's transmission system. The requirement may be met by submitting FERC Form 715, as adopted in Docket No. RM93-10-00, in effect October 30, 1993.	Chapters 7.D., 7.E. and FERC 715 (Confidential Exhibit 3)
(15) A description of the utility's effort to develop and improve the methodology and the data for evaluating a resource (supply-side or demand-side) option's contribution to system wide reliability. The measure of system wide reliability must cover the reliability of the entire system, including transmission, distribution, and generation.	Chapter 7.C., and Chapter 2.D. - Reliability
(16) An explanation, with supporting documentation, of the avoided cost calculation. An avoided cost must be calculated for each year in the forecast period. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. Avoided cost shall include, but is not limited to, the following:	Chapter 9, also see below.

Cross Reference Table

Current IRP Rule Requirements	Report Reference
(A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement.	Chapter 9.A.
(B) The avoided transmission capacity cost.	Chapter 9.B.
(C) The avoided distribution capacity cost.	Chapter 9.C.
(D) The avoided operating cost, including fuel, plant operation and maintenance, spinning reserve, emission allowances, and transmission and distribution operation and maintenance.	Chapter 9.D.
(17) The hourly system lambda and the actual demand for all hours of the most recent historical year available. For purposes of comparison, a utility must maintain three (3) years of hourly data and the corresponding dispatch logs.	Chapter 11 - Appendix B and C.
(18) A description of the utility's public participation procedure if the utility conducts a procedure prior to the submission of an IRP to the commission.	Not applicable
170 IAC 4-7-5 Energy and demand forecasts	
Sec. 5. (a) An electric utility subject to this rule shall prepare an analysis of historical and forecasted levels of peak demand and energy usage which includes the following:	Chapter 3, see below and also Chapter 3. Sections C and D
(1) An historical and projected analysis of a variety of load shapes, including, but not limited to, the following:	Chapter 3.J. - Historical and Projected Load Profiles
(A) Annual load shapes.	Chapter 3.J. - Historical and Projected Load Profiles
(B) Seasonal load shapes.	Chapter 3.J. - Historical and Projected Load Profiles
(C) Monthly load shapes.	Chapter 3.J. - Historical and Projected Load Profiles
(D) Selected weekly and daily load shapes. Daily load shapes shall include, at a minimum, summer and winter peak days and a typical weekday and weekend day.	Chapter 3.J. - Historical and Projected Load Profiles
(2) Historical and projected load shapes shall be disaggregated, to the extent possible, by customer class, interruptible load, and end-use and demand-side management program.	Chapter 3.J. - Historical and Projected Load Profiles
(3) Disaggregation of historical data and forecasts by customer class, interruptible load, and end-use where information permits.	Chapter 3.E.- Base Load Forecast Results
(4) The use and reporting of actual and weather normalized energy and demand levels.	Chapter 3.I. - Weather-Normalization of Load
(5) A discussion of all methods and processes used to normalize for weather.	Chapter 3.I. - Weather-Normalization of Load
(6) A twenty (20) year period for energy and demand forecasts.	Chapter 3.E.- Base Load Forecast Results
(7) An evaluation of the performance of energy and demand forecasts for the previous ten (10) years, including, but not limited to, the following:	Chapter 3.E.- Base Load Forecast Results
(A) Total system.	Chapter 3.E.- Base Load Forecast Results
(B) Customer classes or rate classes, or both.	Chapter 3.E.- Base Load Forecast Results
(C) Firm wholesale power sales.	Chapter 3.E.- Base Load Forecast Results
(8) If an end-use methodology has not been used in forecasting, an explanation as to why this methodology has not been used.	Not Applicable

Cross Reference Table

Current IRP Rule Requirements	Report Reference
(9) For purposes of section 5(a)(1) and 5(a)(2) *[subdivisions (1) and (2)],* a utility may use utility specific data or more generic data, such as, but not limited to, the types of data described in section 4(2) of this rule.	Chapter 3.J. - Historical and Projected Load Profiles and Chapter 3.N.- Load Research Interval Usage Estimation Methodology
Sec. 5. (b) A utility shall provide at least three (3) alternative forecasts of peak demand and energy usage. At a minimum, the utility shall include high, low, and most probable energy and peak demand forecasts based on combinations of alternative assumptions such as:	Chapter 3.G. - Forecast Uncertainty and Range of Forecasts
(1) Rate of change in population.	Chapter 3.C.3.- Long-term Forecasting Models (base case)
(2) Economic activity.	Chapter 3.C. and G.
(3) Fuel prices.	Chapter 3.C. and G.
(4) Changes in technology.	Chapter 3.C.3.- Long-term Forecasting Models (base case)
(5) Behavioral factors affecting customer consumption.	Chapter 3.C.3.- Long-term Forecasting Models (base case)
(6) State and federal energy policies.	Chapter 3.C.3.- Long-term Forecasting Models (base case)
(7) State and federal environmental policies.	Not Applicable
170 IAC 4-7-6 Resource assessment	
Sec. 6. (a) For each year of the planning period, excluding subsection 6(a)(6) *[subdivision (6)]*, recognizing the potential effects of self-generation, an electric utility shall provide a description of the utility's electric power resources that must include, at a minimum, the following information:	Chapter 5.C. and Exhibit 5-1
(1) The net dependable generating capacity of the system and each generating unit.	Chapter 5.C. and Exhibit 5-1
(2) The expected changes to existing generating capacity, including, but not limited to, the following:	Chapter 5.C.
(A) Retirements.	Chapter 5.C.
(B) Deratings.	Chapter 5.C.
(C) Plant life extensions.	Chapter 5.C.
(D) Repowering.	Chapter 5.C.
(E) Refurbishment.	Chapter 5.C.
(3) A fuel price forecast by generating unit.	Chapter 5.C. and Chapter 11 - Appendix F
(4) The significant environmental effects, including:	Chapter 6 and Chapter 11 - Appendix F
(A) air emissions;	Chapter 6 and 6.J. Chapter 11 - Appendix F
(B) solid waste disposal;	Chapter 6 and 6.B. Chapter 11 - Appendix F
(C) hazardous waste; and	Chapter 6 and 6.C. Chapter 11 - Appendix F
(D) subsequent disposal;	Chapter 6 and 6.C. Chapter 11 - Appendix F
at each existing fossil fueled generating unit.	
(5) The scheduled power import and export transactions, both firm and nonfirm, as well as cogeneration and non-utility production expected to be available for purchase by the utility.	Not Applicable
(6) An analysis of the existing utility transmission system that includes the following:	Chapters 7.C., 7.D., 7.E. and 7.F.
(A) An evaluation of the adequacy to support load growth and long term power purchases and sales.	Chapters 7.D., 7.E. and 7.F.
(B) An evaluation of the supply-side resource potential of actions to reduce transmission losses.	Chapters 7.C., 7.D. and 7.E.
(C) An evaluation of the potential impact of demand-side resources on the transmission network.	Chapters 7.C., 7.D. and 7.E.
(D) An assessment of the transmission component of avoided cost.	Chapters 9.B. and 9.D.

Cross Reference Table

Current IRP Rule Requirements	Report Reference
(7) A discussion of demand-side programs, including existing company-sponsored and governmental-sponsored or mandated energy conservation or load management programs available in the utility's service area and the estimated impact of those programs on the utility's historical and forecasted peak demand and energy.	Chapter 4 - Demand Side Management
Sec. 6. (b) An electric utility shall consider alternative methods of meeting future demand for electric service. A utility must consider a demand-side resource, including innovative rate design, as a source of new supply in meeting future electric service requirements. The utility shall consider a comprehensive array of demand-side measures that provide an opportunity for all ratepayers to participate in DSM, including low-income residential ratepayers. For a utility-sponsored program identified as a potential demand-side resource, the utility's plan shall, at a minimum, include the following:	Chapter 4 - Demand Side Management
(1) A description of the demand-side program considered.	Chapter 4 - Demand Side Management
(2) A detailed account of utility strategies designed to capture lost opportunities.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(3) The avoided cost projection on an annual basis for the forecast period that accounts for avoided generation, transmission, and distribution system costs. The avoided cost calculation must reflect timing factors specific to resources under consideration such as project life and seasonal operation.	Chapter 4 - Demand Side Management (discussion) and Chapter 9.A. - Avoided Costs
(4) The customer class or end-use, or both, affected by the program.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(5) A participant bill reduction projection and participation incentive to be provided in the program.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(6) A projection of the program cost to be borne by the participant.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(7) Estimated energy (kWh) and demand (kW) savings per participant for each program.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(8) The estimated program penetration rate and the basis of the estimate.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(9) The estimated impact of the program on the utility's load, generating capacity, and transmission and distribution requirements.	Chapter 4 - Demand Side Management
Sec. 6. (c) A utility shall consider supply-side resources as an alternative in meeting future electric service requirements. The utility's plan shall include, at a minimum, the following:	Chapter 5.D. and Exhibit 2 of the Confidential Supplement
(1) Identify and describe the resource considered, including the following:	Chapter 5.D. and Exhibit 2 of the Confidential Supplement
(A) Size (MW).	Chapter 5.D. and Exhibit 2 of the Confidential Supplement
(B) Utilized technology and fuel type.	Chapter 5.D. and Exhibit 2 of the Confidential Supplement
(C) Additional transmission facilities necessitated by the resource.	Chapter 5.D. and Exhibit 2 of the Confidential Supplement

Cross Reference Table

Current IRP Rule Requirements	Report Reference
(2) Significant environmental effects, including the following:	Chapter 6, Chapter 6.D. and Chapter 11 - Appendix F
(A) Air emissions.	Chapter 6, Chapter 6.D. and Chapter 11 - Appendix F
(B) Solid waste disposal.	Chapter 6 and Chapter 6.B.
(C) Hazardous waste and subsequent disposal.	Chapter 6 and Chapter 6.C.
(3) An analysis of how a proposed generation facility conforms with the utility-wide plan to comply with the Clean Air Act Amendments of 1990.	Chapter 6 - Environmental Compliance
(4) A discussion of the utility's effort to coordinate planning, construction, and operation of the supply-side resource with other utilities to reduce cost.	Chapter 5.B.
Sec. 6. (d) A utility shall identify transmission and distribution facilities required to meet, in an economical and reliable manner, future electric service requirements. The plan shall, at a minimum, include the following:	Chapters 7.B., 7.C., 7.D., 7.E., 7.F., 7.G. and 7.I.
(1) An analysis of transmission network capability to reliably support the loads and resources placed upon the network.	Chapters 7.D., 7.E. and 7.F.
(2) A list of the principal criteria upon which the design of the transmission network is based. Include an explanation of the principal criteria and their significance in identifying the need for and selecting transmission facilities.	Chapters 7.B. and 7.C.
(3) A description of the timing and types of expansion and alternative options considered.	Chapter 7.G. and 7.I.
(4) The approximate cost of expected expansion and alteration of the transmission network.	Chapter 7.G. and 7.I.
170 IAC 4-7-7 Selection of future resources	
Sec. 7. (a) In order to eliminate nonviable alternatives, a utility shall perform an initial screening of all future resource alternatives listed in sections 6(b) through (c) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported.	Chapter 5.D.
Sec. 7. (b) Integrated resource planning includes one (1) or more tests used to evaluate the cost-effectiveness of a demand-side resource option. A cost-benefit analysis must be performed using the following tests except as provided under subsection (e):	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(1) Participant.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(2) Ratepayer impact measure (RIM).	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(3) Utility cost (UC).	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(4) Total resource cost (TRC).	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(5) Other reasonable tests accepted by the commission.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan

Cross Reference Table

Current IRP Rule Requirements	Report Reference
Sec. 7. (c) A utility is not required to express a test result in a specific format. However, a utility must, in all cases, calculate the net present value of the program impact over the life cycle of the impact. A utility shall also explain the rationale for choosing the discount rate used in the test.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
Sec. 7. (d) A utility is required to:	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(1) specify the components of the benefit and the cost for each of the major tests; and	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
(2) identify the equation used to express the result.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
Sec. 7. (e) If a reasonable cost-effectiveness analysis for a demand-side management program cannot be performed using the tests in subsection (b), where it is difficult to establish an estimate of load impact, such as a generalized information program, the cost-effectiveness tests are not required.	Chapter 4 - Demand Side Management and Chapter 10 - Short-Term Action Plan
Sec. 7. (f) To determine cost-effectiveness, the RIM test must be applied to a load building program. A load building program shall not be considered as an alternative to other resource options.	Chapter 4 - Demand-Side Management
170 IAC 4-7-8 Resource integration	
Sec. 8. A utility shall select a mix of resources consistent with the objectives of the integrated resource plan. The utility must provide the commission, at a minimum, the following information:	Chapter 8; also see below.
(1) Describe the utility's resource plan.	Chapter 8.C. and 8.D.
(2) Identify the variables, standards of reliability, and other assumptions expected to have the greatest effect on the least-cost mix of resources.	Chapter 8.C. and 8.D.
(3) Determine the present value revenue requirement of the utility's resource plan, stated in total dollars and in dollars per kilowatt-hour delivered, with the discount rate specified.	Chapter 8.F. - Financial Effects
(4) Demonstrate that the utility's resource plan utilizes, to the extent practical, all economical load management, conservation, nonconventional technology relying on renewable resources, cogeneration, and energy efficiency improvements as sources of new supply.	Chapter 5 and Chapter 8
(5) Discuss how the utility's resource plan takes into account the utility's judgment of risks and uncertainties associated with potential environmental and other regulations.	Chapter 6 and Chapter 8.C.
(6) Demonstrate that the most economical source of supply-side resources has been included in the integrated resource plan.	Chapter 8 (mainly 8.C.)
(7) Discuss the utility's evaluation of dispersed generation and targeted DSM programs including their impacts, if any, on the utility's transmission and distribution system for the first ten (10) years of the planning period.	Chapter 4.F.

Cross Reference Table

Current IRP Rule Requirements	Report Reference
(8) Discuss the financial impact on the utility of acquiring future resources identified in the utility's resource plan. The discussion shall include, where appropriate, the following:	Chapter 8.F. - Financial Effects
(A) The operating and capital costs of the integrated resource plan.	Chapter 8.F. - Financial Effects
(B) The average price per kilowatt-hour as calculated in the resource plan. The price must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule.	Chapter 8.F. - Financial Effects and Figure 8F-1
(C) An estimate of the utility's avoided cost for each year of the plan.	Chapter 9.A.; Exhibit 9-1
(D) The impact of a planned addition to supply-side or demand-side resources on the utility's rate.	Chapter 8.F. - Financial Effects
(E) The utility's ability to finance the acquisition of a required new resource.	Chapter 8.F. - Financial Effects
(9) Identify and explain assumptions concerning existing and proposed regulations, laws, practices, and policies made concerning decisions used in formulating the IRP.	Chapter 6 and also throughout the plan as applicable.
(10) Demonstrate, to the extent practicable and reasonable, that the utility's resource plan incorporates a workable strategy for reacting to unexpected changes. A workable strategy is one that allows the utility to adapt to unexpected circumstances and preserves the plan's ability to achieve its intended purpose. Unexpected changes include, but are not limited to, the following:	See below.
(A) The demand for electric service.	Chapter 8.C.
(B) The cost of a new supply-side or demand-side technology.	Chapter 8.C.
(C) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	Chapter 8.D.
170 IAC 4-7-9 Short term action plan	
Sec. 9. A short term action plan shall be prepared as part of the utility's IRP filing or separately, and shall cover each of the two (2) years beginning with the IRP submitted pursuant to this rule. The short term action plan is a summary of the resource options or programs contained in the utility's current integrated resource plan where the utility must take action or incur expenses during the two (2) year period. The short term action plan must include, but is not limited to, the following:	Chapter 10 - Short-Term Action Plan
(1) A description of each resource option or program included in the short term action plan. The description must include, but is not limited to, the following:	Chapter 10 - Short-Term Action Plan
(A) The objective of the resource option or program.	Chapter 10 - Short-Term Action Plan
(B) The criteria for measuring progress toward the objective.	Chapter 10 - Short-Term Action Plan
(C) The actual progress toward the objective to date.	Chapter 10 - Short-Term Action Plan
(2) The participation of small business in the implementation of a DSM resource option or program.	Chapter 10 - Short-Term Action Plan
(3) The implementation schedule for the resource option or program.	Chapter 10 - Short-Term Action Plan
(4) The timetable for implementation and resource acquisition.	Chapter 10 - Short-Term Action Plan
(5) A detailed budget for the cost to be incurred for each resource or program.	Chapter 10 - Short-Term Action Plan