Received
November 1, 2011
Indiana Utility Regulatory Commission

INDIANA MICHIGAN POWER COMPANY

INTEGRATED RESOURCE PLANNING REPORT
TO THE
INDIANA UTILITY REGULATORY COMMISSION

Submitted Pursuant to
Commission Rule 170 IAC 4-7

November 1, 2011

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VOLUME I

EXECUTIVE SUMMARY

Executive Summary

Indiana Michigan Power Company's (I&M, or "the Company") energy and peak requirements are expected to grow at 0.3% and 0.4% per year, respectively, through 2031. To meet these requirements, I&M analyzed three distinct resource portfolios – 1) one plan that retrofits its larger coal units at Rockport and Tanners Creek to meet new and proposed environmental mandates (Base Plan); 2) a plan that retires Tanners Creek 4 in 2015 and replaces it with a natural gas combined cycle facility in 2017 (Gas Plan), and finally 3), a plan that meets I&M's energy requirements assuming Tanners Creek 4 is retired, and replaces it with market purchases (Market Plan.)

The Base Plan maintains the capacity of Rockport 1 and 2, Tanners Creek 4, and the two Donald C. Cook Nuclear Plant units. Tanners Creek 1-3 are assumed to be retired by December 31, 2014. Renewable capacity and demand response/energy efficiency programs are expanded in the Base Plan. This Base Plan is expected to have a lower cost to customers through 2040, on a cumulative present value basis, than the Gas or Market plans. The Base Plan allows the Company to meet its customer's energy requirements, emission reduction requirements and energy efficiency mandates without subjecting customers to significant risk. The supply-side expansion plan represented in the Base Plan reflects I&M's commitment to DSM programs and compliance with energy efficiency mandates, renewables, and to the need for compliance with environmental regulations.

AEP-East Pool Status

On December 17, 2010, pursuant to Article 13 of the Federal Energy Regulatory Commission (FERC)-approved AEP Interconnection Agreement ("IA," "Interconnection

Agreement" or "AEP Pool"), each of the AEP Pool members gave written notice to the other members, and to American Electric Power Service Corporation ("AEPSC"), the AEP Pool's agent, of its intent to allow for modification-including the possibility of termination- of the Interconnection Agreement, effective January 1, 2014 or such other date as approved by FERC[1]. Because the IA is a rate schedule on file at FERC, its modification, and possible termination, will not be effective until accepted for filing by FERC.

The Interim Allowance Agreement among the AEP companies ("IAA"), which was most recently modified in 1996 and deals with sulfur dioxide (SO_2) emissions and allowances, would likely be terminated. Environmental regulations have expanded beyond those intended to be covered by the IAA. For example, the IAA does not cover the allowance program established for emissions of nitrogen oxides (NO_X). In addition, evolving environmental regulations will likely require unit-specific, rather than system-wide, solutions.

Environmental Compliance Issues

The 2011 Integrated Resource Plan (IRP) considers final and proposed future United States Environmental Protection Agency (EPA) regulations that will impact fossil-fueled electric generating units (EGU).

The EPA has issued final rulemaking to replace the former Clean Air Interstate Rule (CAIR) for the regulation of SO_2 and NO_X which had previously been remanded by

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[1] The timing of the modification or termination of the IA may be affected by the Stipulation pending before the Public Utilities Commission of Ohio in (Case Nos. 11-346-EL-SSO and 11-348-EL-SSO), which, if approved, would require the generating assets in Ohio to be placed in a separate corporation and result in the filing at the FERC to be made in early 2012.

the federal courts. The EPA issued the Cross-State Air Pollution Rule (CSAPR) to establish state-specific emission budgets for SO_2 and both annual and seasonal (May-September) NO_X with a two-phase emission reduction beginning in 2012. Further, the EPA proposed the EGU Maximum Achievable Control Technology (MACT) rule in March 2011 to replace the court vacated Clean Air Mercury Rule (CAMR). As proposed, the EGU MACT rule will regulate emissions of hazardous air pollutants (HAPs) such as mercury, arsenic, chromium, nickel, certain acid gases and organic HAP compounds and is expected to be finalized in December 2011 with full implementation in 2015. The EPA is also expected to propose first-ever requirements regulating greenhouse gas emissions as early as later this year, but the substance of those requirements is not known. Combined, the CSAPR, EGU MACT rule, and other impending federal air regulatory programs will require significant emission reductions from all U.S. coal and lignite-fired units. Emission reductions will be achieved beginning in 2012 as a result of unit retirements, unit curtailments, and installation of emission control technologies, including flue gas desulphurization (FGD) or dry sorbent injection (DSI), selective catalytic reduction (SCR), activated carbon injection (ACI), and fabric filter systems (FF).

In addition, a new rule on the handling and disposal of coal combustion residuals (CCR) is being developed by the EPA, which, as proposed, would require significant additional capital investment in coal-fired EGU necessary to convert “wet” ash and bottom ash disposal equipment and systems—including attendant landfills and ponds—to “dry” systems and in addition build waste-water treatment facilities to process plant groundwater run-off before discharge. EPA is also developing regulations with respect to the intake of cooling water and discharge of wastewater, which has 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, the AEP-East operating companies, and their customers. Such requirements will also accelerate environmental equipment retrofits and proposed retirement dates of any currently non-retrofitted coal unit in I&M and the AEP-East fleet.

The analyses used in developing this IRP assume that greenhouse gas (GHG) legislation or regulation 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 proxy of CO_2 "tax" which would take effect in the approximate 2022 timeframe. The cost of CO_2 is expected to stay within the $15-$30/tonne range over the long-term analysis period; however, a higher cost CO_2 sensitivity case was also developed to test the impact of a literal doubling of CO_2 prices on the plan selection decision.

Summary of I&M and AEP-East Resource Plans

An IRP explains how a utility company will meet the projected capacity (*i.e.*, peak demand) and energy requirements of its customers. By Indiana rule, I&M is required to provide an IRP that encompasses a 20-year forecast period.

Specific I&M capacity additions are listed in Figure 1 and their relative impacts to I&M's capacity position are shown on Figure 2. Accordingly, AEP-East capacity additions are listed in Figure 3 and their relative impacts to AEP-East's capacity position are shown on Figure 4**.** For I&M this includes the construction or acquisition of additional intermediate capacity as well as additional wind purchases to meet both voluntary and mandated renewable goals established in the I&M service territory. Figure 1 also shows that I&M requires **NO** market purchases to meet minimum reserve criteria in PJM. Figure 2 illustrates the importance of DR/EE to I&M, the level for which are largely established pursuant to achieving known state-specific DR/EE mandates.

Figure 1

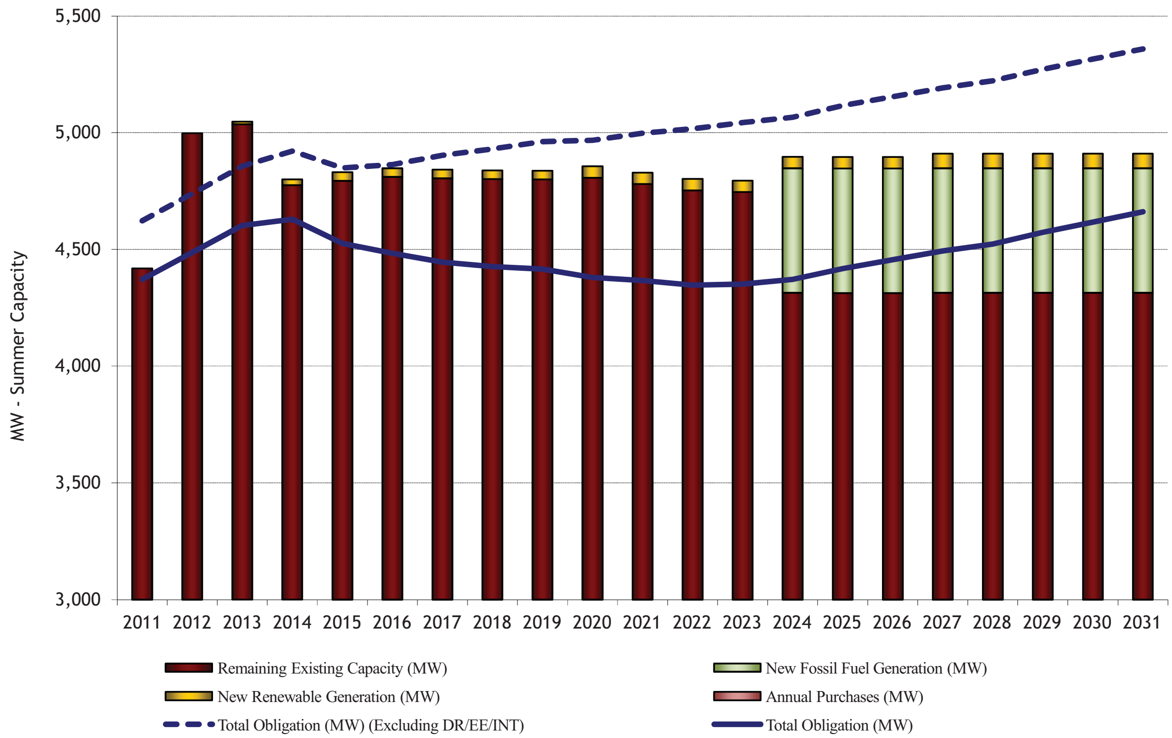
I&M Resource Plan to Meet PJM Reserve Margin Requirements

I&M Capacity Portfolio (Stand-Alone View)

Planning Year	Existing Capacity (MW) (a)		New Capacity (MW)			DR/EE/INT (MW) (c)(d)		Market Purchases (MW)
	Retirements	Rating Adjustments	Renewable (Nameplate)	Renewable (b)	Fossil Fuel	DR/EE	Contracted Interruptible	
2011 /12						14	258	
2012 /13						23	258	
2013 /14			100	13		49	258	
2014 /15	(485)		100	13		123	258	0
2015 /16			100	13		186	258	0
2016 /17						249	258	0
2017 /18						313	258	0
2018 /19						353	258	0
2019 /20						389	258	0
2020 /21		30	100	13		408	258	0
2021 /22						412	258	0
2022 /23						415	258	0
2023 /24						418	258	0
2024 /25	(500)				562	419	258	0
2025 /26						423	258	0
2026 /27						423	258	0
2027 /28			100	13		423	258	0
2028 /29						422	258	0
2029 /30						423	258	0
2030 /31						423	258	0
2031 /32						423	258	0
	(985)	**30**	**500**	**65**	**562**	**423**	**258**	

(a) Not shown are smaller unit derates and uprates (<10MW) which are embedded in the current plan and are largely offsetting. Retirements are shown in the calendar year in which they occur.
(b) Capacity value in PJM is initially set at 13% of nameplate for wind and 38% of nameplate for solar
(c) Energy Efficiency (EE) represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast
(d) Demand Response (DR) represents demand response curtailment programs and tariffs

Figure 2
I&M PJM Capacity Position



In order for AEP-East to maintain its minimum PJM reserve requirement, market purchases, as outlined in Figure 3, are needed as early as the 2014/2015 PJM "planning year". It has been assumed that this purchased capacity would be assigned to AEP-East companies under the existing AEP Pool construct. Under that construct any *short-term* market purchases are allocated to all the AEP-East companies based on their Member Load Ratio (MLR) and, therefore, will **NOT** affect the respective companies' capacity position in the AEP Pool.

Figure 3

AEP-East Resource Plan to Meet PJM Reserve Margin Requirements

AEP-East Capacity Portfolio

Planning Year	Existing Capacity (MW) (a)		New Capacity (MW)			DR/EE/INT (MW) (c)(d)		Market Purchases (MW)
	Retirements	Rating Adjustments	Renewable (Nameplate)	Renewable (b)	Fossil Fuel	DR/EE	Contracted Interruptible	
2011 /12		(10)				123	519	0
2012 /13	(560)		117	20	580	199	519	0
2013 /14			120	21		302	519	0
2014 /15	(3,747)	(136)	232	38		570	519	1,776
2015 /16	(278)		215	32		823	519	1,643
2016 /17			150	20	602	1,100	519	843
2017 /18			150	20		1,365	519	757
2018 /19			117	20		1,478	519	823
2019 /20			100	13		1,617	519	888
2020 /21		35	271	40		1,765	519	885
2021 /22			100	13		1,870	519	1,052
2022 /23			100	13		1,955	519	1,158
2023 /24			200	26		2,026	519	1,230
2024 /25	(500)		21	8		2,080	519	1,718
2025 /26					2,236	2,130	519	0
2026 /27						2,142	519	0
2027 /28			100	13	550	2,142	519	0
2028 /29			50	7		2,140	519	0
2029 /30					550	2,142	519	0
2030 /31						2,142	519	0
2031 /32					562	2,142	519	0
	(5,085)	**(111)**	**2,043**	**301**	**5,080**	**2,142**	**519**	

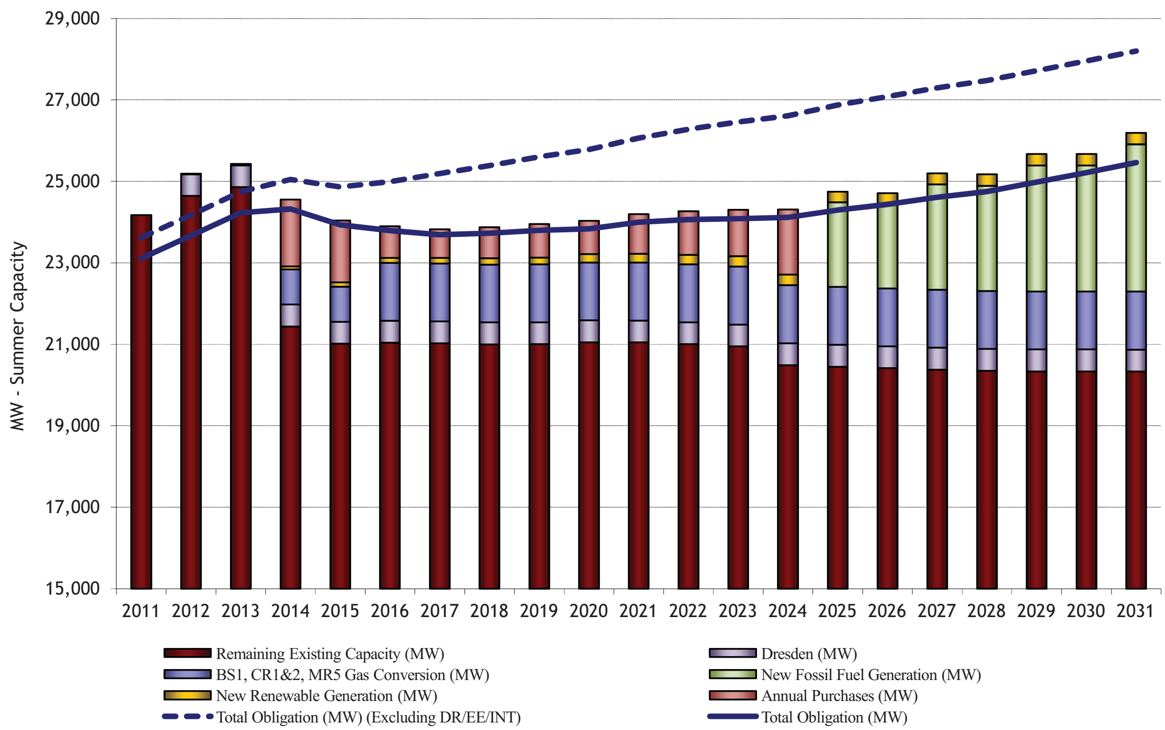
(a) Not shown are smaller unit derates and uprates (<10MW) which are embedded in the current plan and are largely offsetting. Retirements are shown in the calendar year in which they occur.

(b) Capacity value in PJM is initially set at 13% of nameplate for wind and 38% of nameplate for solar

(c) Energy Efficiency (EE) represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast

(d) Demand Response (DR) represents demand response curtailment programs and tariffs

Figure 4
AEP-East PJM Capacity Position



This IRP provides for reliable electric utility service, at reasonable cost, through a combination of traditional supply, market (purchased power) options, renewable supply and demand side programs. I&M and AEP-East will provide for adequate capacity resources to serve their customers' peak demand and required PJM reserve margin needs throughout the forecast period.

Conclusion

This IRP is being presented at a time of great uncertainty with regard to the future status of I&M's relationship to the other AEP-East generating companies. The AEP Pool construct, which has been in place since 1951 (with modifications over time) will likely be modified, or potentially terminated, by 2014 or sooner. The final outcome of pending environmental regulations may require a significant level of capacity retirements in a relatively short period of time. The final outcome of this uncertainty makes it a challenge to commit to large capital investments in new generating capacity in the near term. Over the next six to twelve months, environmental rules will be finalized and AEP Pool negotiations will be underway, and that may provide a higher level of certainty with regard to actions the Company should embrace. Until that certainty is realized, the Company's plan is to maintain optionality and flexibility in meeting the requirements of its customers.

Therefore, in this IRP, future market purchases for AEP-East over this 20-year forecast period ideally represent initial "placeholders" for such incremental capacity resource needs. It is the Company's intent to continually investigate and analyze the economic merits of future opportunities to build or acquire "owned-resources" in lieu of market purchases to ensure greater (local) electrical reliability and price certainty for its customers. However, it should be considered that in the PJM region, most load serving entities (LSE) receive capacity through the market construct known as the Reliability Pricing Model (RPM) auction process. So while the concept of relying on the market may not be the approach chosen by the AEP-East operating companies, it is an accepted practice for many utilities in the region.

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. In light of the current economic conditions and the movement towards increasing use of renewable generation and end-use energy efficiency, as well as known and proposed environmental rulemaking to further control fossil plant emissions which could result in the retirement, conversion, or retrofit of existing generating units, supply of capacity and energy to I&M will continue to be impacted. The resource planning process is becoming increasingly complex when considering pending legislative and 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 customers will be a primary consideration in this report.

1)SYNOPSIS

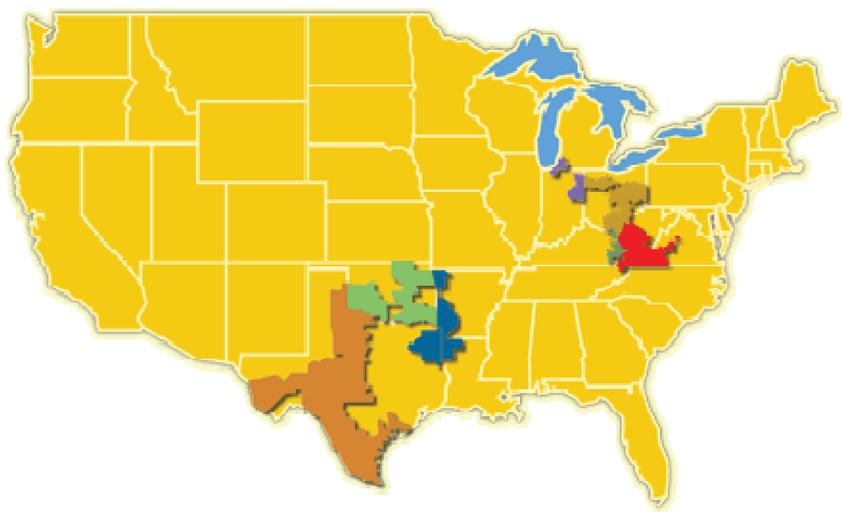
1. Synopsis

A. Overview

I&M serves 586,000 customers in Indiana and Michigan, including 458,000 in eastern and north central Indiana. 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. Its headquarters is 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; Michigan's largest nuclear facility, Cook Plant; and six hydroelectric generating stations along the St. Joseph River – two in Indiana and four in Michigan.

[2] Includes AEP Generating Company's (AEG) share of Rockport 1310 MW.



The AEP System

This Integrated Resource Plan (IRP) presents the electrical load forecast for I&M for the period 2011-2031, a resource analysis covering the period 2012-2031, 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.

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. To I&M's benefit, this process is carried out by various work groups drawing upon diverse knowledge and various areas of expertise. Many internal working groups have contributed to the I&M plan, led by a core multidisciplinary team with a combined total of 134 years of experience in IRP analysis. Additionally, these functional groups were assisted by several outside consulting organizations, 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 & Operational Analysis	Overview-Supply/Demand	8
John Torpey	Director - Integrated Resource Planning	Resource Planning Development	4
Jon MacLean	Manager - Resource Planning	Supply-Demand and Other Factor Integration	35
Mark Becker	Manager - Resource Planning Modeling	*Strategist*® Optimization Modeling	28
William Castle	Director - Resource & DSM Planning	Demand-Side Management	5
Randy Holliday	Staff Economist	Energy & Demand Forecasting	26
John McManus	VP-Environmental Services	Environment Compliance	20
Kamran Ali	Manager Transmission Planning	Transmission Planning	4
Brian West	Regulatory Case Manager	IRP Project Coordinator	1

*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 2011 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 programs in its IRP process. To highlight a few examples, the Company uses:

- *Strategist*® to optimize its plan and alternatives and risk assessment, and
- PROMOD IV® and PCI GENTRADER® for short and long-term production cost simulations, and
- *Aurora*^{XMP}, for portfolio risk simulation analysis.

Generally, these are industry accepted, often proprietary, software modeling tools.

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 DOE data.

The Company uses consultants and industry sources when deemed appropriate. For example, assumptions incorporated in the DSM analysis stem from the *Indiana Market Potential Study* performed by Forefront Economics and the *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.*, authored by the Electric Power Research Institute (EPRI). These, or similar, studies provide targeted, credible data necessary to inform critical assumptions.

C. Supply-Side Assessment

In the planning process several major drivers impact I&M's supply-side resources, namely:

- The age of the fossil-fueled generation fleet;
- the impact of final and proposed future United States Environmental Protection Agency (EPA) regulations, State legislated renewable portfolio standards (RPS) or voluntary Clean Energy initiatives; and
- the current mix of capacity which relies heavily on baseload generating assets.

I&M's requirements are influenced by the terms of the AEP pool agreement (see Chapter 2A and Chapter 5B). This IRP tentatively states that I&M will not add any major new baseload generation during the 2012-2031 forecast period. However, I&M will see an increase in both its DSM and renewable (Wind) programs as I&M continues to comply with mandatory, and conform with voluntary alternative/renewable resource requirements. As a result, even with the proposed retirements of Tanners Creek 1-3, I&M will not need to add any additional traditional capacity until late in the forecast period. The IRP does require that I&M add a 562 MW (summer rating) natural gas combined cycle (NGCC) when Tanners Creek 4 is retired. Exhibit 8-10 shows that I&M has positive reserve margins through the end of the forecast period.

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.

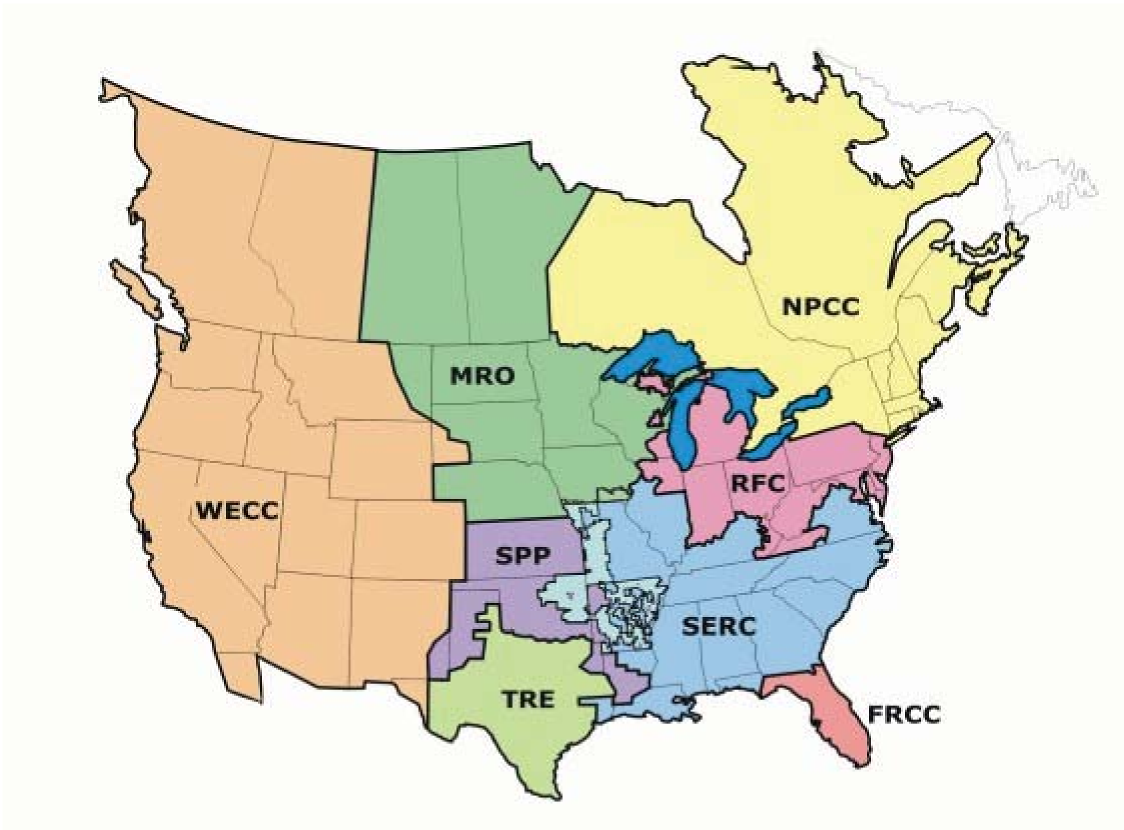
Because I&M's installed generation is nearly 40 percent nuclear, I&M and its customers have less risk exposure to environmental challenges that may threaten other EGUs. I&M has already implemented a number of pollution control projects to minimize the residual environmental effects of solid and hazardous waste at its facilities and to comply with existing and former air emission regulations, such as with the Title IV acid rain and the NO_X SIP Call programs.

Even with reduced risk exposure I&M faces a variety of environmental compliance challenges with the finalized CSAPR, the New Source Review (NSR) Consent Decree and the proposed EGU MACT rule. 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, 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 Reliability*First* Corporation (RFC), a Regional Entity of the

North American Electric Reliability Corporation (NERC).



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

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.

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"). This IRP includes energy efficiency programs designed to comply with that order. Also, this IRP validates the cost-effectiveness of energy efficiency and other demand-side programs including emerging smart grid technologies and demand response programs.

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 additional tariffs for potential offering to customers on an ongoing basis.

In accordance with the Settlement Agreement approved by the Commission on June 13, 2007 in Cause No. 43231, I&M implemented and completed a smart meter pilot in South Bend, IN as part of its gridSMART® program. The results of the pilot were mixed and as a result, increased or substantial investment in smart meters will be deferred. However, emerging smart grid technologies such as Integrated Volt VaR

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[3] Demand Side Management (DSM) refers to utility activities designed primarily to encourage consumers to modify patterns of their electricity usage, including the timing and level of electricity demand. This includes Demand Response (DR) offerings that reduce peak demand (kW) and Energy Efficiency (EE) programs that encourage energy (kWh) conservation.

Control (IVVC) continue to be evaluated.

Reflective of the Company's commitment to sustainability and environmental responsibility, this IRP fully includes the impacts of the Phase II Order, emerging smart grid technologies, and demand response programs in Indiana. Greater detail is provided in Chapters 4 and 10.

G. Major Assumptions

AEP load forecasts specifically 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), the Energy Improvement and Extension Act of 2008 (EIEA) and the American Recovery and Reinvestment Act of 2009 (ARRA).

The most dominant issue in the short-term load forecast is 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 carbon dioxide (CO_2), will be significantly affected by any greenhouse gas (GHG) legislation. 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 and AEP.

EPA is poised to propose first-ever GHG requirements for power plants as early as the end of this year. Given that there are currently no cost-effective post-combustion control technologies available, the standards are anticipated to focus on energy efficiency opportunities, but the substantive requirements of the EPA proposal are not yet known. AEP supports a legislative approach to resolve the GHG issue rather than a regulatory approach. Without this certainty, it is impossible to justify expenditures in the billions of dollars in GHG mitigation strategies that might otherwise put the company and its shareholders at risk. Such legislation appears unlikely in this Congress and diminished somewhat in future Congresses.

For this IRP cycle, the impact of GHG legislation is modeled as a simple carbon dioxide price or tax on solid fuels and as a part of the price of natural gas. This carbon tax is projected to take effect in the 2017-2022 time frame.

In recognition of current and possible future state renewable portfolio standards (RPS), and as a method of reducing GHG emissions, this IRP reflects achievement of state renewable mandates and conformance with voluntary state goals.

The resource plan developed for I&M assumes that I&M and the AEP System-East Zone remain responsible for the generation supply of their retail customers.

H. Cross-Reference Table

The following cross-reference table provides a link between the 170 IAC rule and 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.

Cross Reference Table

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 12 - Appendix A and Confidential Exhibits 5 and 6
(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 Conf. Exhibit 5
(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

IRP Rule Requirements	Report Reference
(9) A description of the generation expansion planning criteria used in developing the integrated resource plan. The description must fully explain the basis for the criteria selected, including an analysis and rationale for the level of system wide generation reliability assumed in the IRP.	Chapter 2.D. - Reliability Criteria
(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 (Conf. Exhibit 4)
(A) Solved real flows.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(B) Solved reactive flows.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(C) Voltages.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(D) Detailed assumptions.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(E) Brief description of the model(s).	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(F) Glossary of terms with cross references to the names of buses and line terminals.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(G) Sensitivity analysis, including, but not limited to, the forecast of the following:	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(i) Summer and winter peak conditions.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(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 (Conf. Exhibit 4)
(iii) Branch circuit ratings, including, but not limited to, normal, long term, short term, and emergency.	Chapter 7.B. and FERC 715 (Conf. Exhibit 4)
(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 (Conf. Exhibit 4)
(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 7 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 (Conf. Exhibit 4)
(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 (Conf. Exhibit 4)
(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

Cross Reference Table

IRP Rule Requirements	Report Reference
(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.
(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 12.B. and C.- Appendix
(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

Cross Reference Table

IRP Rule Requirements	Report Reference
(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
(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 Conf. Exhibit 1
(4) The significant environmental effects, including:	Chapter 6 and Conf. Exhibit 2
(A) air emissions;	Chapter 6, see also Chapter 6.J. and Conf. Exhibit 2
(B) solid waste disposal;	Chapter 6, see also Chapter 6.B. and Conf. Exhibit 2
(C) hazardous waste; and	Chapter 6, see also Chapter 6.C. and Conf. Exhibit 2
(D) subsequent disposal;	Chapter 6, see also Chapter 6.C. and Conf. Exhibit 2

Cross Reference Table

IRP Rule Requirements	Report Reference
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.	Chapter 5.B.
(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.
(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

Cross Reference Table

IRP Rule Requirements	Report Reference
(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 3 of the Confidential Supplement
(1) Identify and describe the resource considered, including the following:	Chapter 5.D. and Exhibit 3 of the Confidential Supplement
(A) Size (MW).	Chapter 5.D. and Exhibit 3 of the Confidential Supplement
(B) Utilized technology and fuel type.	Chapter 5.D. and Exhibit 3 of the Confidential Supplement
(C) Additional transmission facilities necessitated by the resource.	Chapter 5.D. and Exhibit 3 of the Confidential Supplement
(2) Significant environmental effects, including the following:	Chapter 6, Chapter 5.D. and Exhibit 3 of the Conf. Supplemt
(A) Air emissions.	Chapter 6, Chapter 5.D. and Exhibit 3 of the Conf. Supplemt
(B) Solid waste disposal.	Chapter 6 and Chapter 5.D.
(C) Hazardous waste and subsequent disposal.	Chapter 6 and Chapter 5.D.
(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

IRP Rule Requirements	Report Reference
(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
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.E. and 8.F.
(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.B. and 8.C.
(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.H. - 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.D.

Cross Reference Table

IRP Rule Requirements	Report Reference
(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.D.
(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.
(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.H. - Financial Effects
(A) The operating and capital costs of the integrated resource plan.	Chapter 8.H. - 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.H. - Financial Effects and Exhibit 8-12
(C) An estimate of the utility's avoided cost for each year of the plan.	Chapter 9.A.; Exhibit 9-1 and 9-2
(D) The impact of a planned addition to supply-side or demand-side resources on the utility's rate.	Chapter 8.H. - Financial Effects
(E) The utility's ability to finance the acquisition of a required new resource.	Chapter 8.H. - 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.D.
(B) The cost of a new supply-side or demand-side technology.	Chapter 8.D. and 8.D.2.
(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

Cross Reference Table

IRP Rule Requirements	Report Reference
(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

2) OBJECTIVES AND PROCESS

2. Objectives and Process

A. Introduction

The AEP Service Corporation provides management, technical, and financial services to the operating companies. I&M's parent company, American Electric Power (AEP), serves a population of about 7.2 million customers (3.2 million retail customers) in a 41,000 square-mile area in parts of Arkansas, Indiana, Kentucky Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. AEP is based in Columbus, Ohio. In 2010 the residential, commercial, and industrial customers accounted for 30.7%, 23.2%, and 33.0%, respectively, of AEP-East total internal energy requirements of 125,381 GWh. The remaining 13.1% was supplied for use in the public street and highway lighting, sales-for-resale, and all other categories.

I&M is one of five operating companies of the AEP System-East Zone for which generation assets are currently planned and operated on an integrated basis under the FERC-approved AEP Interconnection Agreement ("IA," "Interconnection Agreement" or "AEP Pool".) AEP has seven East Zone operating companies, but two do not include generation resources. This Interconnection Agreement provides for mutual assistance during emergencies, maximum dependability in the day-to-day production of the electric power requirements of all AEP customers, and maximum economies of scale. The AEP System-West Zone includes portions of Texas, Louisiana, Oklahoma and Arkansas.

On December 17, 2010, pursuant to Article 13 of the Interconnection Agreement, each of the AEP Pool members gave written notice to the other members, and to American Electric Power Service Corporation ("AEPSC"), the AEP Pool's agent, of its intent to modify the Interconnection Agreement, effective January 1, 2014 or such other date as approved by FERC[4]. Because the IA is a rate schedule on file at FERC, its modification will not be effective until accepted for filing by FERC.

The Interim Allowance Agreement among the AEP companies ("IAA"), which was most recently modified in 1996 and deals with sulfur dioxide (SO_2) emissions and allowances, would be terminated. Environmental regulations have expanded beyond those covered by the IAA. For example, the IAA does not cover the allowance program established for emissions of nitrogen oxides (NO_X). In addition, evolving environmental regulations will likely require unit-specific, rather than system-wide, solutions.

By giving notice to modify, and possibly terminate, the IA and terminate the IAA, the AEP Pool members are providing a framework and timeline within which all interested stakeholders have an opportunity to participate in the determination of how the AEP-East operating companies should operate prospectively. This process has already begun in several states, for example I&M has engaged with several stakeholders in Indiana and Michigan. Other AEP Pool members have made similar contacts with stakeholders in their respective state jurisdictions.

Assuming this AEP Pool modification/termination notice is not revoked or significantly modified, by 2014, I&M's resource planning relationship with the other AEP-East companies could take one of a number of plausible forms. Rather than plan for every potential outcome, which would not be particularly efficient or beneficial, I&M has

[4] The timing of the modification or termination of the IA may be affected by the Stipulation pending before the Public Utilities Commission of Ohio in (Case Nos. 11-346-EL-SSO and 11-348-EL-SSO), which, if approved, would require the generating assets in Ohio to be placed in a separate corporation and result in the filing at the FERC to be made in early 2012.

analyzed two potential conditions. First, an integrated resource plan (IRP or "Plan") for I&M as a stand-alone entity beginning in 2014 has been created. A second plan with I&M as part of the AEP-East Pool in its existing construct has also been considered, however, the AEP Pool plan yields the same resource additions for I&M as the No AEP Pool plan.

This IRP document neither pre-supposes the AEP Pool/Stand-Alone end-state, nor does it make any recommendation regarding AEP-East company relationships in a "post-AEP Pool" world. Rather, it merely presents a plan for I&M to meet its obligations under the two potential governance scenarios outlined above.

This IRP is being presented at a time of great uncertainty with regard to the future status of I&M's relationship to the other AEP-East generating companies. The AEP Pool construct, which has been in place since 1951 (with modifications over time) will likely be modified by 2014. The final outcome of pending environmental regulations may require a significant level of capacity retirements in a relatively short period of time. Over the next three to six months, proposed environmental rules will be finalized and AEP Pool negotiations will be underway, and that may provide a higher level of certainty with regard to actions the Company should embrace. Until that certainty is realized, the Company's plan is to maintain optionality and flexibility in meeting the requirements of its customers.

Therefore, in this Plan, future market purchases (for AEP-East) over this 20-year forecast period ideally represent initial "placeholders" for such incremental capacity resource needs. It is the Company's intent to continually investigate and analyze the economic merits of future opportunities to build (or acquire) "owned-resources" in lieu of such purchases to ensure greater (local) electrical reliability and price certainty for its customers. However, it should be considered that in the PJM region, most load serving entities (LSE) receive capacity through the market construct known as the Reliability Pricing Model (RPM) auction process. So while the concept of relying on the market may not be the approach chosen by the AEP-East operating companies, it is an accepted practice for many utilities in the region.

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. In light of the current economic conditions and the 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 likely result in the retirement, conversion or retrofit of existing 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.

Exhibit 8-10 and Exhibit 8-11 show that both I&M and AEP-East, under their recommended plans, are anticipated to meet their reserve margin requirements over the forecast period.

B. Objectives

The purpose of this report is to present I&M's IRP process and the resulting plan. The resulting plan (The Plan) is intended to provide the lowest reasonable cost of power to I&M's customers while meeting environmental and reliability constraints. The Plan should be both flexible and robust, so the need to make changes is minimized.

C. Assumptions

1. Environmental

This IRP considers final and proposed future United States Environmental Protection Agency (EPA) regulations, as described in Chapter 6, which will impact fossil-fueled electric generating units (EGU).

The EPA has issued final rulemaking to replace the former Clean Air Interstate Rule (CAIR) for the regulation of SO_2 and NO_X which had previously been remanded by the federal courts. The EPA issued the CSAPR to establish state-specific emission budgets for SO_2 and both annual and seasonal (May-September) NO_X with a two-phase emission reduction beginning in 2012. Further, the federal EPA proposed the EGU Maximum Achievable Control Technology (MACT) rule in March 2011 to replace the court vacated Clean Air Mercury Rule (CAMR). EGU MACT will regulate emissions of hazardous air pollutants (HAPs) such as mercury, arsenic, chromium, nickel, certain acid gases and organic HAP compounds and is expected to be finalized in November 2011 with full implementation in 2015. The EPA is also expected to propose first-ever requirements regulating GHG emissions later this year, but the substance of those requirements is not known. Combined, the CSAPR, MACT rule, and other impending federal air regulatory programs will require significant emission reductions from all U.S. coal and lignite-fired units. Emission reductions will be achieved beginning in 2012 as a result of unit retirements, unit curtailments, and installation of emission control technologies, including flue gas desulphurization (FGD) or dry sorbent injection (DSI), selective catalytic reduction (SCR), activated carbon injection (ACI), and fabric filter systems. In the AEP-East states, these new and proposed emission reduction programs will accelerate planned environmental retrofit projects and will drive unit curtailments beginning in 2012.

In addition, a new rule on the handling and disposal of coal combustion residuals (CCR) is being developed by the EPA, which, as proposed, would require significant additional capital investment in the coal-fired EGU to convert "wet" ash and bottom ash disposal equipment and systems—including attendant landfills and ponds—to "dry" systems and in addition build waste-water treatment facilities to process plant groundwater run-off before discharge. The EPA is developing regulations with respect to the intake of cooling water and discharge of wastewater, which also has the potential to require significant capital investment for compliance.

The cumulative cost of complying with these final and proposed environmental rules will be highly burdensome to I&M, the AEP-East operating companies, and their customers. Such requirements will also accelerate proposed retirement dates of any currently non-retrofitted coal unit in the AEP-East fleet as established within this 2011 IRP, as discussed in Chapter 5.

2. Customer Base

This report assumes that both the I&M and AEP System-East Zone customer bases remain relatively stable, for the duration of the planning period.

3. "Market vs. Build" Considerations

In addition to the fundamental capacity pricing information in the modeling (discussed below), available information suggests that capacity reserve margins–inclusive of current and anticipated merchant capacity–will decline to the point that new assets will have to be built within the next decade in the PJM area that includes the AEP System-East Zone.

The need for new capacity will increase as the impact from final and proposed EPA legislation, as mentioned in Chapter 6, is experienced and accelerated unit retirements occur as a result.

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. This requirement is itself 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 PJM as a whole and generating asset equivalent forced outage rates represent other factors impacting the LSEs' 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.

A required PJM IRM of 15.3% was used as the starting point for the plan. However, the AEP System-East Zone's actual reserve margin requirement is closer to 12%. This stems from the diversity between the AEP System-East Zone peak and the PJM RTO peak. Historically, the AEP System-East Zone has experienced about 3% diversity against PJM peaks and as a result the AEP System-East Zone's capacity obligation is roughly 3% lower, when described in terms of the zonal peak, than it would be if described in terms of the peak coincident with PJM.

Although the current plan contains a changing mix of capacity through time, it also contains uncertainty surrounding the long-term forecast. As a result, the AEP System-East Zone IRM has held steady at 15.3% 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 AEPSC 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 AEP to set forth its future AEP System -East Zone capacity resource plan under, essentially, a “self-planning” format. This is an approach that would, however, initially not give AEP access to those generating sources offered into the PJM capacity auction, but rather would allow AEP 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.

AEP has opted out of the RPM capacity auction through the 2014/15 delivery year, for which the auction was held in May 2011 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 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, reliability and environmental requirements are constantly re-assessed to balance the interests of all stakeholders: customers, regulators, and shareholders.

1. Planning Organization

This report presents results based on input received from many functional areas coordinated by 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

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 October 2010 by Moody's Analytics. The forecast is based on load experience prior to 2011. Moody's Analytics projects moderate growth in the U.S. economy during the 2011-2031 forecast period, characterized by moderate inflation and a 2.4% average annual rise in real Gross Domestic Product (GDP), with the consumer price index expected to rise by 2.2% per year. Industrial output, as measured by the Federal Reserve Board's index of industrial production, is projected to grow at 1.1% 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 0.4% per year during 2011-2031, with real regional income per-capita growth of 1.5%.

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 0.3% from 2012 to 2031, this is slightly lower than the 0.4% forecasted for the AEP System-East Zone as a whole. 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 0.4% and 0.2%, respectively, with annual peak demand expected to continue to occur in the summer season through 2031.

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.

For those long-term forecasts that are quarterly, a monthly load shape is applied to the forecast based on analysis from the short-term models. 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’ October 2010 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 energy forecast for the AEP System–East Zone, by customer class, is obtained by summing the forecasts, by customer class, of each of the AEP System–East Zone operating companies. The same method is used to determine the forecast of peak internal demand and adjusting for diversity.

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 and 3-2. Page 1 of Exhibit 3-1 depicts the development stages of all internal energy requirements forecasts. Pages 2 through 9 of Exhibit 3-1 provide the stages of the Statistically Adjusted End-Use Models for the residential and commercial sectors. Exhibit 3-2 presents a schematic of the peak demand and internal energy requirements forecasting process. 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.

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 important difference between the short-term and long-term forecasting models is their treatment of energy prices, which are only included in long-term forecasts. This approach makes sense because although consumers may suffer sticker shock from energy price fluctuations, there is little they can do to impact them in the short-term. They already own a refrigerator, furnace or industrial equipment that may not be the most energy-efficient model available. 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 2000 through October 2010.

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 (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 are 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 1984-2010. The long-term energy sales forecast is developed by blending 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. Natural Gas Price Forecast

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 *2010 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 mortgage interest rate provides a measure for household formation, while service area real gross regional product per capita provides a measure of economic growth in the region, which will also 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 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 1990 through September 2010. This model incorporates the effects of the Energy Policy Act of 2005 (EPAct), the Energy Independence and Security Act of 2007 (EISA), American Recovery and Reinvestment Act of 2009 (ARRA) and Energy Improvement and Extension Act of 2008 (EIEA) on the residential energy.

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 September 2010. As with the residential SAE model, the effects of the EPAct, EISA, ARRA and EIEA are captured in this model.

f. Industrial Energy Sales

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

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

Service area employment 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 quarterly 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 is the same as for the short run models. These models are monthly and have the follow 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

Forecast values for 2011 are generally taken from the short-term process. Forecast values for 2012 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by the end of 2012 the entire forecast is from the long-term models. This blending allows for a smooth transition between the two separate processes, minimizing the impact of any differences in the results.

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, 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 3-3 presents I&M's annual internal energy requirements forecasted for the years 2011-2031, and on actual requirements from the years 2001-2011 (with 2011 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 3-4 and 3-5 present the corresponding information for I&M's Indiana and Michigan service areas, respectively. Also, Exhibit 3-6 provides a disaggregation of the forecasted "other internal sales" figures shown on Exhibits 3-3 to 3-5.

For the AEP System–East Zone, information on actual and forecasted annual internal energy requirements is given on Exhibit 3-7.

Exhibits 3-8 and 3-9 show, for I&M and the AEP System–East Zone, respectively, 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 3-3 through 3-9 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), AEP System–East Zone service-area employment, 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. All variables are expressed in logarithms. 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 0.9% and 2.2% per year, respectively, compared to 1.6% for the base case. The low- and high-case growth rates for AEP-East Zone region total employment were 0.1% and 0.9% per year, respectively, compared to 0.5% per year for the base case. For the real price of natural gas, the low case assumed a growth rate of 1.6% per year, and the high case assumed a growth rate of 0.9% per year. These compare to a base-case growth rate of 1.2% for the average real gas price in the seven states served in the AEP System–East Zone. Real electricity price high and low cases assumed average annual growth rates of 1.0% and 0.5%, respectively. Meanwhile, the base case for real electricity price assumed an average annual growth of 0.8%. 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 the AEP System–East Zone and I&M are tabulated in Exhibits 3-10 and 3-11, respectively. Graphical displays of the range of forecasts of internal energy requirements and summer peak demand for the AEP System–East Zone and I&M are shown in Exhibits 3-12 and 3-13.

For AEP System–East Zone, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2031, represent deviations of about 7% below and 7% above, respectively, the base-case forecast (with the corresponding I&M forecast showing about the same percentage deviation). In this regard, the low-case and high-case growth rates in summer peak internal demand for the forecast period were 0.1% and 0.7% per year, respectively, compared to 0.4% per year for the base case.

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 3-14, 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 and 2011 (the current forecast). Exhibit 3-15 presents the same information for the AEP System–East Zone.

I. Weather-Normalization of Load (170 IAC 4-7-5(a) (4) and (5))

Exhibit 3-16 compares the recorded (i.e., actual) and weather-normalized summer and winter peak internal demands and annual internal energy requirements for both I&M and the AEP System-East Zone, respectively, for the last ten years, 2001-2010.

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 produce 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 3-17 to 3-21 display various historical and forecasted load profiles pertinent to the planning process. Exhibit 3-17 shows profiles of monthly peak internal demands for the AEP System–East Zone and I&M on an actual basis for the years 2001 and 2006, and as forecasted for 2011 (includes actual data through August), 2021 and 2031. Exhibit 3-18 shows, for the winter-peak month and summer-peak month for the years 2005 and 2010, respectively, the AEP System's–East Zone average daily internal load shape for each day of the week, along with the peak-day load shape. Exhibit 3-19 shows the corresponding daily internal load shapes for I&M.

Exhibit 3-20 displays, for the forecast years 2011 and 2021, AEP System'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 corresponding profiles for I&M are displayed in Exhibit 3-21.

AEP maintains an on-going load research program consisting of samples of each major rate class in each jurisdiction. Exhibit 3-22 displays I&M's Indiana jurisdiction residential, commercial and industrial customer class summer and winter 2010 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 3-23 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 2010 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 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 the MV90 Load Research Package. This industry accepted program combines the individual customer hourly data for each sample point in each stratum, weights the stratum results according to the original sample design parameters, and combines the weighted stratum results into class level results. 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 Kema 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. Through 2010, 37 customers have signed up for this program.

However, customer self-generation (including co-generation) historically has been minimal in the I&M service territory. For a variety of reasons, including the price of electricity, I&M customers generally have not found self-generation to be cost effective. The underlying factors that limit self-generation are not expected to significantly change in the future and, therefore, customer self-generation did not affect projected load during the forecast period.

4) DEMAND SIDE MANAGEMENT

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 demand-side management (DSM) programs designed to encourage customers to become more aware of their consumption levels, use electricity efficiently, conserve energy, and use appropriately incentivized, cost-effective electro-technologies. The load impacts of these programs are embedded in I&M's actual load experience and its load forecast.

Prior to 2007, various factors, primarily low avoided costs for energy and demand, resulted in I&M offering a variety of DSM-related tariffs only. I&M's robust reserve of relatively low cost capacity created challenges in the justification and promotion of cost-effective demand-side management and energy efficiency programs.

As discussed in Chapter 3, the characteristics of the current and projected I&M customer load are different today than they were in the past. Although significant gains in end-use efficiency have been achieved from government standards, changes in the marketplace, and customer choices and behavior, a depressed economy and the governments' stimulus activity has recently intensified the focus and desire for energy efficiency. A heightened sensitivity of environmental issues and the desire for all things "green" have also escalated in recent years. As a result, in 2007, I&M proposed to implement energy efficiency programs that would promote and incent the purchase and installation of more efficient end-use electro-technologies that would help customers reduce their consumption. Through settlement efforts and approval from the Commission, I&M, as a member of the Program Implementation Oversight Board, implemented seven third-party designed energy efficiency programs during 2010. In compliance with the

Commission's Phase II Generic Order, Cause 42693, issued on December 9, 2009, I&M next developed a Three Year DSM Plan, Cause 43959, which contained Core and Core Plus Program offerings aimed at meeting and/or exceeding the energy savings goals set forth in the Generic Order. This plan was approved on April 27, 2011. Concurrent to I&M's initiation of energy efficiency programs since 2007, as discussed in Chapter 1.F. and in Chapter 4.E.1, AEP embarked on a system-wide project, referred to as gridSMART®. The gridSMART effort, which includes I&M's portfolio of energy efficiency programs, aims to create a holistic corporate-wide approach to incorporating technology, in part, to achieve increased efficiency in utility operations and to further develop potential DSM offerings to customers. I&M's existing energy efficiency programs are currently marketed under the gridSMART® umbrella and Core Plus Programs will be marketed in the same manner.

B. Current DSM Programs

I&M has seven energy efficiency programs implemented, five of which are Core Programs (or similar to Core Programs). The remaining two are Core Plus Programs. Core Programs will be transitioned to the Third Party Administrator for implementation in January, 2012 on a statewide basis as directed in the Phase II Generic Order. The two Core Plus Programs will continue to be implemented by I&M as part of the Three Year DSM Plan Core Plus portfolio. The seven programs currently implemented include Residential Rebates (Lighting), Residential Low & Moderate Income Weatherization, Residential Home Energy Audit (audits, direct installs, and weatherization), Energy Efficient Schools (education & take home kits), C&I Prescriptive, Residential Appliance Recycling, and C&I Custom. A listing of the eighteen programs contained in I&M's

Three Year DSM Plan is provided in the Short Term-Action Plan section of this report.

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 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. This plan reflects compliance with those mandates.

To that end, this plan reflects current program impacts as well as impacts from as yet undefined future programs. 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.

To achieve the goals, a mix of traditional consumer programs and smart grid technologies will likely be necessary and both are considered in this IRP. AEP remains internally committed to install measures designed to achieve system-wide peak demand reductions of 1,000 MW and energy reductions of 2,250 GWh by year-end 2012. Since 2008 and through the second quarter of 2011, over 500 MW and 1,320 GWh of EE and DR have been installed on the AEP-East System. It is expected that I&M Indiana will achieve 51 MW and 265 GWh, from 2008 -2012.

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 the reduced utility bill for any up-front investment in a building/appliance/equipment modification, upgrade, or new technology. If the consumer feels that the new technology is a viable substitute and will pay him or her back in the form of reduced bills over an acceptable period, he or she will adopt it.

EE measures include efficient lighting, weatherization, efficient pumps and motors, efficient HVAC infrastructure, and efficient appliances, most commonly. Often, multiple measures are bundled into a single program that might be offered to either residential or commercial/industrial customers.

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

Numerous studies have been published which quantify the amount of available “cost-effective” EE. Typically, and for the purposes of this IRP, this has meant measures that pass the “total resource cost” (TRC) test, meaning that the measure “pays for itself” in energy and capacity savings, regardless of whether or not its cost may be subsidized by the utility. The results of some notable studies are summarized below:

	Economic Potential		
Study	Utility Programs	Other	Total
EPRI 2009 (National)	13%	N/A	N/A
Forefront Economics 2008 (I&M Indiana)	16%	N/A	N/A
McKinsey & Company 2009 (National)	N/A	N/A	23%
MEAA Residential 2006 - (Michigan)[1]	13%	N/A	N/A
MEAA Residential 2006 - (Indiana)[1]	13%	N/A	N/A
Black & Veatch 2009 (I&M Michigan)	27%	N/A	N/A

[1] Includes subset of Technical Potential with levelized cost less than $100/MWh.

While there is some disagreement about what the actual number may be and some differences in methodologies, it is reasonable to assume that there is a fairly large well of latent cost-effective EE available. What becomes a question of policy is how much of the available efficiency should be pursued with utility-sponsored programs, and included as a resource.

Unlike supply-side resources, demand-side resources, particularly EE resources require the participation of thousands of consumers. While the math may indicate that an “investment” in a particular measure is cost-effective, it does not guarantee that it will be universally adopted.

Market barriers to EE exist which limit the rate and ultimate level at which efficiency measures are adopted by consumers (program participants).

Market Barriers to Energy Efficiency	
High First Costs	Energy-efficient equipment and services are often considered "high-end" products and can be more costly than standard products, even if they save consumers money in the long run.
High Information or Search Costs	It can take valuable time to research and locate energy efficient products or services.
Consumer Education	Consumers may not be aware of EE options or may not consider lifetime energy savings when comparing products.
Performance Uncertainties	Evaluating the claims and verifying the value of benefits to be paid in the future can be difficult.
Transaction Costs	Additional effort may be needed to contract for EE services or products.
Access to Financing	Lending industry has difficulty in factoring in future economic savings as available capital when evaluating credit-worthiness.
Split Incentives	The person investing in the EE measure may be different from those benefiting from the investment (e.g. rental property).
Product/Service Unavailability	Energy-efficient products may not be available or stocked at the same levels as standard products.
Externalities	The environmental and other societal costs of operating less efficient products are not accounted for in product pricing or in future savings.

Source: Eto, Goldman, and Nadel (1998): Eto, Prahl, and Schlegel (1996); and Golove and Eto (1996)

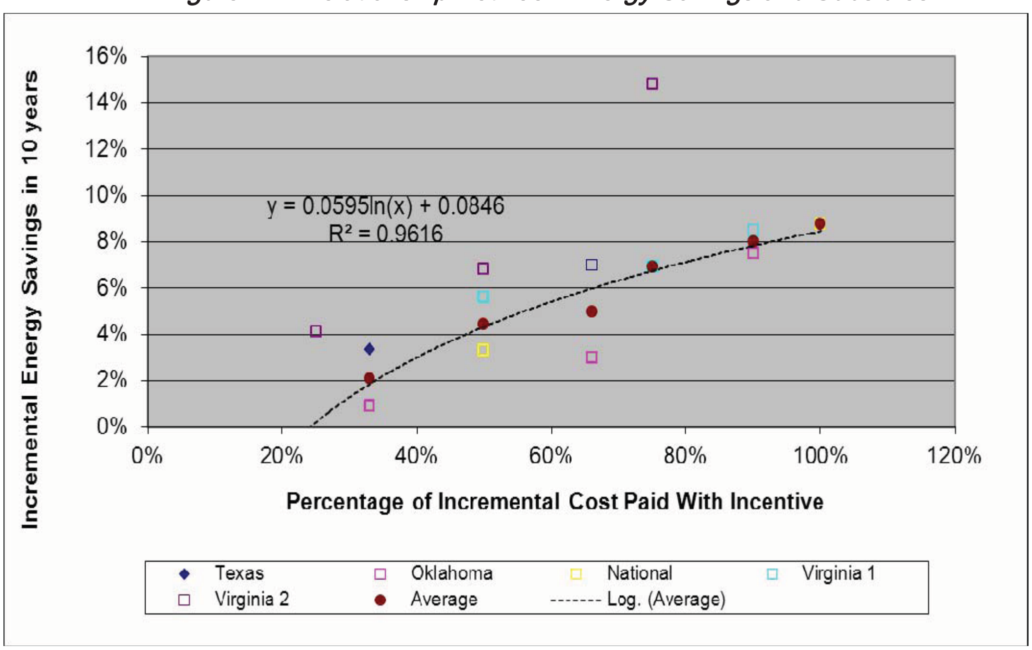
To overcome many of the participant barriers noted above, a portfolio of programs may often include several of the following elements:

- 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 burdens and marketing. A market penetration function was derived from market potential studies for I&M and other AEP jurisdictions. Figure 4-1 shows that higher levels of EE can be achieved as the subsidies to participants (incentives) are increased. It also shows an intuitive degree of diminishing returns where increases in the incentive (expressed as a percentage of the measure cost) have a decreasing effectiveness.

Figure 4-1: Relationship Between Energy Savings and Subsidies



Source: Resource Planning

2. Smart Meters: gridSMART®¯Smart Meter Pilot Program

In March 2011, Indiana Michigan Power Company collaborating with the Indiana Office of the Utility Consumer Counselor documented their findings and recommendations pertaining to the Smart Meter Pilot Program (SMPP or Pilot) in South Bend, Indiana. The pilot included approximately 9,600 advanced metering infrastructure (AMI) smart meters. Among other grid reliability objectives, the Pilot sought to define the potential impact of advanced consumer programs on customer energy consumption, peak demand and energy cost.

Advanced consumer programs were introduced to provide customers a better way to control energy consumption and cost. The first was an advanced time-of-day (TOD) tariff for both residential and commercial customers. The initial residential off-peak rate was 5.4 cents/kWh and the on-peak rate was 16.8 cents/kWh; whereas, the commercial off-peak rate was 7.0 cents/kWh and the on-peak rate was 18.1 cents/kWh. A total of 146 residential customers and 1 commercial customer enrolled in this program. This exceeded the initial established residential goal of 50 customers and exceeds the 12 residential customers in the SMPP area that are on I&M standard TOD rate. However, the total participation of 146 (2.2%) residential qualifying SMPP customers and one commercial customer indicates an overall weak customer response to the advanced TOD tariff offerings.

The second advanced offering was a residential cooling direct load control (DLC) program offered in conjunction with the installation of a Programmable Communicating thermostat (PCT) installed in the home. The PCT allowed the temperature of the home to be adjusted upward a maximum of 4ºF degrees during summer peak times in exchange for a monthly bill credit. I&M capped the number of program participants at 126 due to PCT technology issues. Program participation was well below the projected 500 customer goal set prior to the implementation due to these technology-related issues and a lack of customer participation.

The SMPP demonstrated that customers can accrue tangible benefits from smart grid deployments. First and foremost, those limited number of customers (2.2%) willing to participate in peak period time differentiated tariff programs, and those that actively participated, will reduce their peak demand, shift energy consumption out of the on-peak period, reduce total energy consumption and save money. Customers enrolled in the TOD rate program reduced their summer peak demand by 10.8% (.21kW) and their annual energy consumption by 1.5% (150kWh). These results compared favorably to the hypothesized 3.5% energy and peak demand reductions. TOD program customers saved an average of $28 annually representing a 3.6% reduction in their electric bill. Annual savings accrued to approximately 75% of the program participants with a vast majority of the savings occurring from September-May when all energy usage was priced at the discounted off-peak rate. The overall satisfaction rate for the program was 83% and no customers left the program except those who left the service territory.

I&M conducted eight DLC events in 2009 and 12 in 2010. Due to technology limitations and low implementation level in 2009, only data from 2010 events was analyzed to determine the program impact. Two types of events were conducted in 2010: 1) adjust the temperature a total of 4 degrees in two-2 degree steps and 2) adjust the temperature a total of 4 degrees in one step. The peak demand reduction from these adjustments was 1.2 kW per participant and the average demand reduction over a four-hour timeframe was 1.03 kW. The peak demand reduction represents a 43% decrease in normal customer demand. This reduction compares favorably to the original projection of a pre-program 1 kW reduction per customer. The limited participating DLC customers, on average, reduced annual energy consumption by 0.5% (50kWH) and saved $40.30 annually representing a 4.6% reduction in their electric bill. Overall program satisfaction rate was 88% and only one person exited the program without leaving the service territory. However, these DLC customers when allowed to override the load control programs without limitation or energy cost penalties tended to do so and ultimately reduce achievable demand savings.

Customers were able to view and analyze consumption data using the interactive web portal to identify ways to further conserve energy and save costs. Thirty-four percent of the SMPP area customers signed up on the I&M web site which increased the registrants from approximately 300 prior to the Pilot to almost 3,200 in September, 2010. While many customers registered to use the web site, a vast majority of the customers said they had not viewed their usage (87%). There was no discernible difference between the group of customers with web access to their consumption information and those who did not register for the web.

In summary, I&M believes the SMPP demonstrated the following:

- An integrated set of smart grid technologies and advanced customer programs can allow customers the ability to reduce their energy and peak demand consumption and save money;
- While the smart grid deployments provide the utility with some operational benefits, it is projected these distribution benefits alone do not exceed the entire cost of an integrated smart grid deployment. What is needed is active residential, commercial and industrial customer participation and a thorough understanding of energy cost benefits from a smart grid application; and

- SMPP was 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. Based on I&M business modeling, a minimum customer participation rate of between 11% to 25%, with equal participation between tariff offerings, will be required. 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. Furthermore, while many customers registered to use the interactive web portal, 87% of customers never checked their energy usage. <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 Integrated Volt VaR Control (IVVC), "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 rates, an industrial customer allows the utility 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.

In addition to the demand response (DR) program associated with the SMPP, I&M has interruptible contracts with larger customers amounting to 258MW of realized capacity reductions coincident with PJM's peak. Additional peak demand reduction capability is being pursued with the introduction of tariff-based DR offerings for C&I customers.

Expanding DR options beyond interruptible industrial contracts is likely necessary to achieve increased peak demand reductions. Many commercial businesses participate in DR activities that selectively reduce load in exchange for capacity payments from PJM. For this IRP, it is assumed that future demand reduction programs would consist of additional tariffs (summer and winter impacts) as well as Company-offered, summer-only DR similar to what is currently required within PJM.

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.

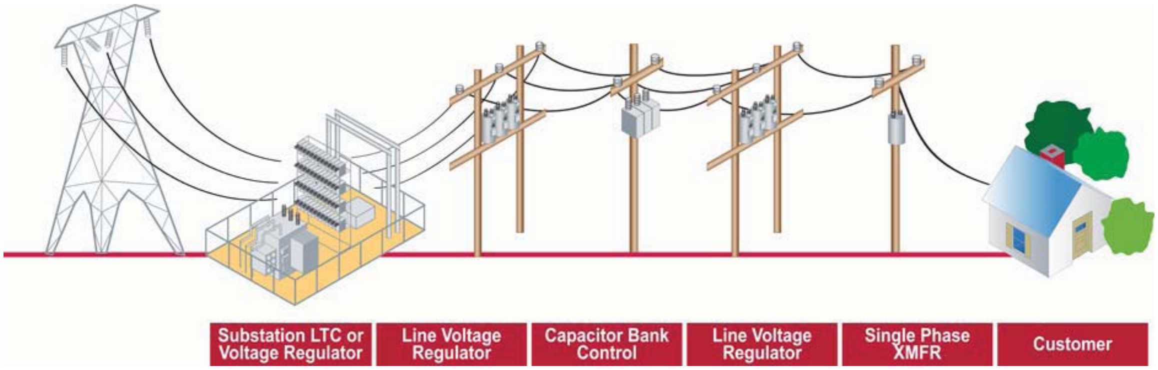
This IRP assumes a modest level of incremental DR to be met in part with PJM-compliant tariffs. Other options, including residential DR may also be considered in the future.

4. Integrated Volt VaR Distribution Infrastructure

Integrated Volt VaR Control (IVVC) provides all of the benefits of power factor correction, voltage optimization, and condition-based maintenance in a single, optimized package. In addition, IVVC 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 0.5% to 0.7% 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 4-2). Consumers will simply use less energy to accomplish the same tasks.

Figure 4-2: Integrated Voltage/VaR Control



Source: Resource Planning

5. Technologies Considered But Not Evaluated

Distributed Generation to include roof-top solar, microturbines, combined heat and power (CHP), and residential and small commercial wind.

Currently, these technologies cost more than other options and were not considered for wide-scale utility implementation. Their costs will continue to be monitored.

	Mean installed cost ($/kW)	Installed cost range (+/- $/kW)	Fixed O&M ($/kW-yr)	Fixed O&M (+/- $/kW-yr)	Variable O&M ($/kWh)	Variable O&M (+/- $/kWh)	Annual degradation rate (%/yr)
PV	$ 6,200	$ 1,200	$ 21	$ 6			0.5% to 0.8%
Wind 1 to 19kW	$ 7,500	$ 2,300			$ 0.02	$ 0.01	
Wind 20 to 100kW	$ 5,200	$ 1,800	$ 50	$ 20			
Wind 100 to 1000 kW	$ 2,500	$ 1,000	$ 50	$ 20			
Biomass Combustion CHP*	$ 5,500	$ 2,000			$ 0.09	$ 0.05	

* Unit cost is per unit kilowatt of the electrical generator, not the boiuler heat capacity

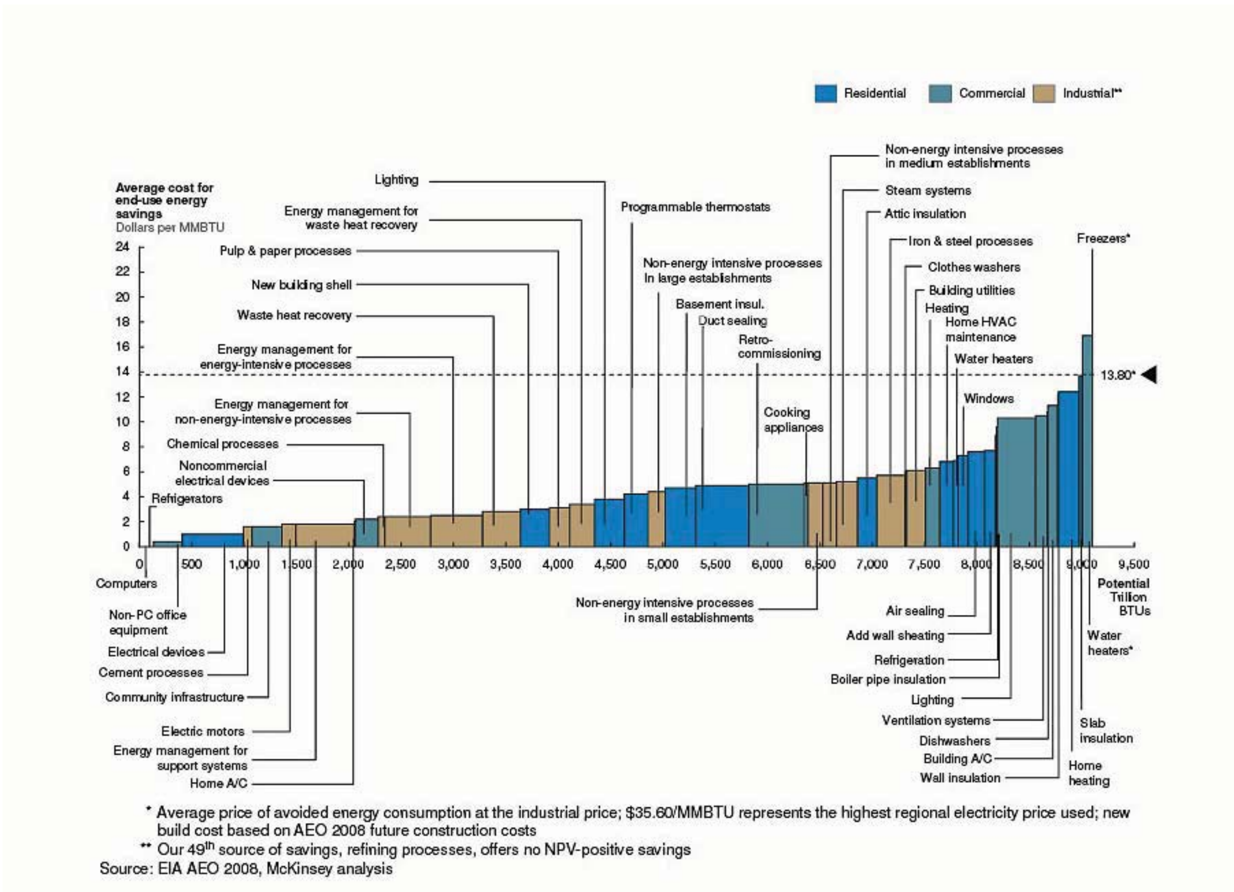
Reproduced from: http://www.nrel.gov/analysis/pdfs/dg_lcoe_data.pdf

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 4-3, 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 and programs which encompass a range along the cost curve.

Figure 4-3: EE Supply Curve



When determining the cost of the resource portfolio as a whole, the levelized resource cost of the EE portfolio, in aggregate, was assumed to be $40/MWh which is consistent with numerous studies (approximately equivalent to $4.00/MMBtu). The absolute value is not critical to verifying cost-effectiveness as will be shown. The real variable from the perspective of the utility and utility commissions is how much will a program cost and what results can be expected.

By evaluating the load forecast with and without EE, the difference can be considered the value, or benefit of the efficiency portfolio. This can then be compared to the costs of the EE portfolios. Because the per-unit cost of the measures are held constant, the variation in the portfolio costs (program costs) are due to the levels of EE and the incentive necessary to achieve those levels. Also, a break-even analysis was completed to determine the aggregate average measure cost that cannot be exceeded for the portfolio to be cost-effective from a total resource perspective.

The following table shows the costs and benefits of the Energy Efficiency embedded in the forecast given the assumption of an average resource cost of $4/MMBtu. Increases in that cost assumption will decrease the net benefits. This comprehensively analyzes current and future energy efficiency programs in the context of the dynamic modeling performed by *Strategist*, Cost-effectiveness of individual programs is discussed in the Short-term Action Plan.

Incentive Level	PV of Benefits ($000)	Nominal Program Costs ($000)	PV of Program Costs ($000)	Net Benefit ($000)
50%	979,229	334,525	208,001	771,228
75%	979,229	501,659	311,922	667,307
100%	979,229	668,893	415,905	563,324

The break-even, levelized cost of efficiency measures from a total resource cost perspective approached $10/MMBtu, or approximately $0.49/kWh installed. Program costs would be a fraction of these costs.

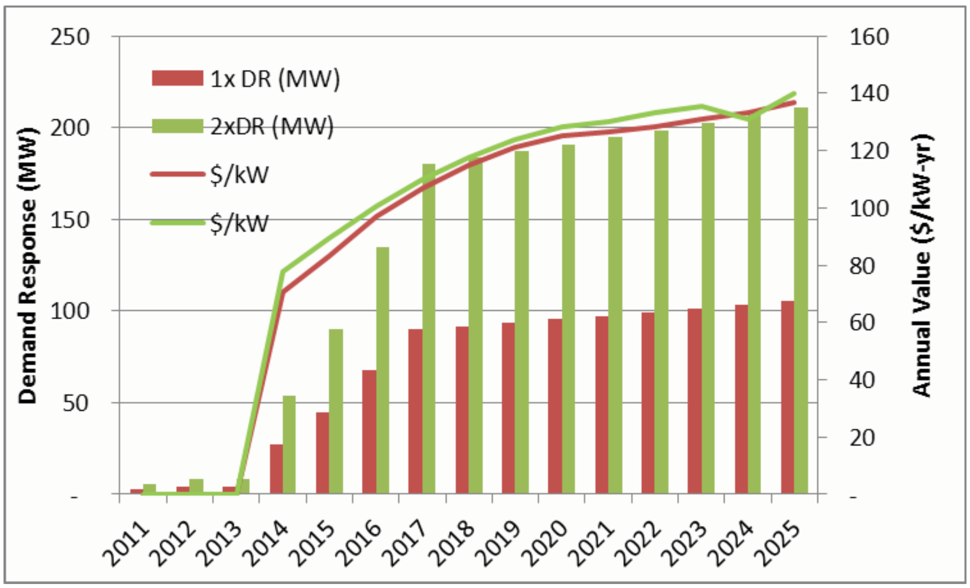
Because EE is an investment today for future savings and also results in spreading current fixed costs among fewer kilowatt hours, the net result is often an increase in rates, *even as* total bills (revenue requirements) decrease. Thus, a balance is sought between aggressive pursuit of efficiency and the full acknowledgement of this expected impact on rates.

A description of the current programs is included in the Short-term Action Plan.

2. Demand Response

As before, the base portfolio evaluation is completed with and without DR program/assets to determine its benefit. From there a break-even cost is calculated which becomes a cost-to-beat as DR options are pursued during the implementation phase. Additionally, as a sensitivity, the level of demand response assumed was doubled to gauge the benefits.

Figure 4-4: I&M Indiana Demand Response Values



As can be seen from Figure 4-4, demand response has little immediate value due to low capacity prices within PJM but very quickly ramps up. Achieving demand response at prices lower than shown in the graph will reduce the revenue requirement. A 100 MW reduction represents approximately 3% of peak load for all of I&M. However, that is incremental to current contracted interruptible load that already exceeds 7% of ultimate demand.

3. IVVC

Similar to EE, the base portfolio was prepared with *and* without IVVC and compared to the costs.

Annual Energy Savings (GWh)	Annual Peak Demand Reduction (MW)	PV Benefit ($000)	Capital Costs ($000)	PV Costs ($000)	Net Benefit ($000)
35	6.7	19,197	7,489	6,498	12,699

This result is somewhat scalable with the limit being available circuits that are worthwhile upgrading.

4. Smart Meters

Given the results of the 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. Discussion and Conclusion

As a result of the requirements of the Indiana DSM Phase II order, an aggressive ramp up of energy efficiency programs is currently 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 10-1. I&M may benefit from further investment in demand response, particularly in the commercial and industrial space where costs are lower on a per unit basis. Further, investment in promising smart grid technologies like IVVC can reduce customer bills passively, skirting many of the barriers that inhibit rapid and universal adoption of traditional energy efficiency measures.

F. DSM and Distributed Generation: Distribution and Transmission Applications

The focus of this section up to this point has been on avoidance of generation. DSM and distributed generation (DG), including storage technologies such as Sodium

Sulfur (NaS) Batteries, also have the potential for greater use on the transmission and distribution system as technology improvements are made and costs are reduced.

For the distribution system, DG and DSM applications can be integrated with distribution switching technologies for peak shaving and/or reliability improvement applications. These DG systems will require the use of real time data to ensure that safety and power quality are maintained in the operation of the system. In peak shaving, DG application(s) would be activated based on operational factors so grid constraints are mitigated. These operational factors could include voltage, current, frequency and/or temperature indicators, which can be managed and used for decision-making through software applications or monitored by a system dispatcher. For reliability improvement applications, DG can strategically be placed on existing feeders and the feeder configured to automatically switch to “islanding” mode when the main station feed is interrupted. Islanding involves the electrical isolation of a portion of the feeder so that it can be safely and reliability fed from the DG application(s). This DG application will require real time data for determining the state of the local distribution grid and a robust communication system for timely and accurate processing of the data.

From a transmission planning perspective, DG and DSM are modeled as built-in inputs into the annual assessments. These inputs are established by PJM as part of the Reliability Pricing Model (RPM) and Base Case development effort. In the absence of these inputs, more transmission improvements could be required. As a member of PJM, any proposed solutions to transmission problems will be reviewed by PJM through its stakeholder process to ensure compatibility of the proposed solution on a regional basis.

Currently, DG technologies have a very high capital cost, particularly when sized conventionally to meet peak demand. If costs continue to decline as expected and new ways to utilize storage are conceived, it is possible that this technology will become a larger part of future resource plans.

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 Contract Service - Interruptible Power tariffs and demand response riders recently 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.

The Company makes available Rider ECS, Emergency Curtailable Service (ECS) and Rider EPCS, Energy Price Curtailable Service (EPCS) to our commercial and industrial customers taking service under Tariff IP, Industrial Power. These additional interruptible service options address temporary, or short-term, emergency operating conditions on the AEP System. In the event of curtailments, such customers receive a curtailable credit based on the amount of energy curtailed and the respective pricing provisions of these riders.

I&M also offers interruptible service via PJM's Demand Response program. 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 / billing credit in exchange for curtailing demand and energy. These are 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 2012 forecast year, and annually thereafter, it is anticipated that six interruptible customers with contracted interruptible capacity of approximately 375 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 243 MW (summer rating) for I&M. In addition to these interruptible customers, the Company has 19 demand response and 106 direct load control customers that may be interrupted under certain conditions, with these customers having 40.5 MW of demand reduction capacity.

H. Current Time-Of-Use Service Options

Another contributor to I&M's demand-side management programs include optional special rates with time-of-use "demand-side" features.

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 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 receive reduced rates and I&M has the potential to reduce costs and realize efficiency gains in producing electricity.

I&M offers a standard and an experimental time-of-day (TOD), storage water heater, load management time-of-day and off-peak forgiveness provisions to its customers. The standard time-of-day provision is available to all customers and provides on-peak and off-peak energy charges. The experimental time-of-day provision also provides on-peak and off-peak energy charges and is 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. The load management time-of-day provision is 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 over 16,100 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 on-peak period is defined as 7 A.M. to 9 P.M., Monday through Friday. The off-peak period is all other hours not defined during the on-peak period.

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 in Time-Of-Use, Interruptible and Demand Response Tariffs – Table 1 shown directly below.

Time-Of-Use, Interruptible and Demand Response Tariffs – Table 1

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 on-peak and off-peak energy charges. Limited to first 2,500 customers (Indiana).	Indiana, Michigan	5,513
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 on-peak and off-peak energy charges.	Indiana	140
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 off-peak hours and store it for use during on-peak hours.	Indiana, Michigan	1,394

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	17,167
Rider DLC-2	Interruptible	Experimental program available to residential customers located within the former South Bend Smart Meter Pilot area under which customers authorize the Company to install a smart thermostat device to control the customer's central electric cooling unit.	Indiana	106
Rider R.P.R.	Interruptible	Available on a voluntary basis for customers receiving residential electric service. Customers cannot take service under this Rider while also taking service under Rider D.L.C or Rider D.L.C.-2. To participate, customers 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	0

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
SGS-LMTOD	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 off-peak hours and store energy for use during on-peak hours. These tariffs provide on-peak and off-peak energy charges.	Indiana, Michigan	59
SGS-TOD	Time-Of-Use	Experimental program available to single-phase small general service customers 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	2
MGS-LMTOD	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 off-peak hours and store energy for use during on-peak hours. These tariffs provide on-peak and off-peak energy charges.	Indiana, Michigan	144
LGS-TOD	Time-Of-Use	Available to general service customers with demands greater than 10 kW but less than 1,000 kW. This tariff provides on-peak and off-peak energy charges.	Indiana	11

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
LGS-LMTOD	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	25
MGS-TOD	Time-Of-Use	Available for general service customers with demands greater than 10 kW but less than 150 kW (Indiana) and zero to 150 kW (Michigan). Electric service will be measured through one multi-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods. This tariff provides on-peak and off-peak energy charges.	Indiana, Michigan	1,264
LGS (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	1,906

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
LP (Off-Peak Hour Provision)	Time-Of-Use	Available for general service customers with contracted capacity of 1,500 kW. 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	26
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 tariff schedule.
IP (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	231

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
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	3
EHS (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	47
CS – IRP	Interruptible	Available to customers operating at 34 kV or higher who contract for service under one of the Company's interruptible service options. The total contract capacity for all customers served under this tariff and Tariff IRP is limited to 135,000 kVA. This tariff has been withdrawn except for existing installations.	Indiana	3

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
CS-IRP2	Interruptible	Available to customers with interruptible demands of 1,000kW/kVA who contract for service under one of the Company's interruptible service options. The total contract capacity for all customers served under this tariff, Tariff CS-IRP, and Riders DRS1 and DRS2 is limited to 235,000 kVA in Indiana and 50,000 kW in Michigan.	Indiana, Michigan	5
Special Interruptible Contract	Interruptible	Special Contract provides for curtailment of load.	Indiana	1
Rider ECS (Emergency Curtailable Service)	Interruptible	Rider ECS is available to customers normally taking firm service under Tariff IP (Indiana) or Tariff LP (Michigan) for their total capacity requirements from the Company. Customer's ECS load will be curtailed when an emergency condition exists on the AEP System. The customer must have an on-peak curtailable demand not less than 1 MVA and will be compensated for kWh curtailed under the provisions of Rider ECS. Customer selects one of two ECS curtailment options based upon maximum duration and credit amounts. Customer will be subject to curtailment for no more than 50 hours per season.	Indiana, Michigan	0
Rider EPCS (Energy Price Curtailable Service)	Interruptible	Rider EPCS is available to customers normally taking firm service under Tariff IP (Indiana) or Tariff LP (Michigan) for their total capacity requirements from the Company. Customer's PCS load	Indiana, Michigan	0

Schedule	Time-Of-Use / Interruptible Category	Description	Jurisdiction	Number of Participants
		will be curtailed at the Company's sole discretion. The customer must have an on-peak curtailable demand not less than 1 MW/MVA and will be compensated for kWh curtailed under the provisions of the Rider. Customer selects one of three EPCS curtailment duration options. Customer specifies the maximum number of days during the season that the customer may be requested to curtail. Indiana customers select notification on a day ahead and/or current day basis. The customer also specifies the minimum price at which the customer would be willing to curtail. The Company, at its sole discretion, determines whether the customer will be curtailed given the customer's specified PCS curtailment options.		
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	16
D.R.S.-2	Interruptible	Available to commercial and industrial customers who voluntarily respond to locational marginal prices (LMP) by reducing consumption and receives a payment for those reductions during times when LMP prices are high. 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
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
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	17

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 customers through its provision within I&M-Indiana's Terms and Conditions of Service.

Note3: The tariff descriptions shown above are in summary form. To obtain a full description, please see the Company's tariff sheets and Terms and Conditions of Service.

The Time-Of-Use Demand Reduction – Table 2, shown below, reflects I&M's demand reduction in MW for each off-peak tariff schedule as of September 2011.

Time-Of-Use Demand Reduction - Table 2

Class	**Coincident Peak Demand Reduction (MW)**
Residential LMWH	3.1
Residential WH80	0.3
Residential WH100	0.2
Residential WH120	2.0
Residential TOD2	0.0
Residential TOD	0.1
Residential OPES	0.1
MGS LMTOD	0.4
SGS TOD & LMTOD	0.0
MGS TOD	2.4
MGSTOD3CO	0.0
LGS LMTOD	1.0
LGS TOD	0.2
IP Primary	6.3
IP Subtrans	1.4
IP Transmission	1.8
IP Secondary	3.3
Total	22.8

5) SUPPLY-SIDE RESOURCES

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. AEP Interconnection Agreement

The current planning and operation of the generation facilities of the five major operating companies in the AEP System's-East Zone, including I&M, is coordinated through the AEP Interconnection Agreement. The AEP Interconnection Agreement, commonly referred to as the "pool agreement," was originally signed in 1951 and has been modified and supplemented from time to time since then. The AEP Pool allows each of the members to receive the economies of scale that result from a large system.

The pool agreement provides a mechanism to compensate individual operating companies for imbalances that may exist from time to time with respect to the installed generating capacities of the AEP Pool member companies. Under the accounting provisions of the pool agreement, each member is responsible to provide for its member load ratio of the total AEP Pool generating capacity. Member load ratio for each month is the ratio of the Company's peak load during the prior twelve months to the sum of the five companies' non-coincident peak loads during the same period. Each capacity-surplus AEP Pool member is credited on a monthly basis for its surplus capacity in excess of this requirement, and receives payments from the capacity-deficit members, at a rate that reflects the embedded investment cost of its own primary steam capacity and the fixed operating rate of this capacity. These payments to the capacity-surplus AEP Pool members are made by the capacity-deficit members, in proportion to their respective capacity deficits. Payments are made at the primary capacity equalization rate for the AEP Pool, which reflects the weighted average of the embedded investment cost of primary steam capacity and the fixed operating rates of all the capacity-surplus members. I&M is currently a capacity surplus member.

As stated in Section 2.A., on December 17, 2010, each of the AEP Pool members gave written notice to the other members, and to AEPSC, of its intent to allow for modification of the pool agreement, effective January 1, 2014 or such other date as approved by FERC. Because the AEP Pool agreement is a rate schedule on file at FERC, its modification will not be effective until accepted for filing by FERC.

2. AEP System 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 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 regional transmission organization (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

Four AEP companies (APCo, CSP, 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 the AEP System-East Zone and for I&M as of June 1, 2011. Figure 5-1 summarizes the data in Exhibit 5-1 and also includes, for information, the PJM RTO installed capacity (including purchases) by fuel type as of May 31, 2011 (http://www.pjm.com/~/media/markets-ops/ops-analysis/capacity-by-fuel-type-2011.ashx). Total PJM RTO capacity is 181,619 MW of which 39.70% is coal fired, 34.08% is gas/oil and 18.50% is nuclear. The 2011 summer I&M capacity of 5,546 MW and the 2011 summer AEP System - East Zone capacity of 27,999 MW are composed of the following resource types (MW):

Figure 5-1

2011 Generating Capacity

	I&M	East Zone	PJM RTO
Coal	3,208	20,991	72,098
Nuclear	2,059	2,059	33,600
Hydro/Pumped Storage	12	684	7,821
Gas Diesel	0	2,821	46,975
Oil	0	0	14,923
Purchase	242	1,329	4,040
Renewable	25	116	2,163
Total	5,546	27,999	181,619

Note: Totals do not include DSM/EE program values

2. Current (Embedded) Capability Adjustments

The capability forecast of the existing AEP System-East Zone generating fleet over the 2012-2031 forecast period reflects a reduction of approximately 111 MW as a result of unit deratings associated with environmental facility retrofit, and Coal-to-Gas unit conversions, netted against upgrades associated with planned efficiency improvements.

Output changes to I&M generating units are shown in Figure 5-2 as well as Exhibit 5-2. Note that while Figure 5-2 and Exhibit 5-2 both show specific technology additions to Rockport, a decision as to the particular Rockport Unit that will be first retrofitted is still being evaluated.

Figure 5-2

Year	Month	Unit	Modification	Capacity Change (MW) Total Unit	I&M
2014	1	Tanners 4	FGD (DSI)	0	0
2014	1	Rockport 2	FGD (Technology TBD)	0	0
2015	1	Tanners 1	Retirement	-145	-145
2015	1	Tanners 2	Retirement	-145	-145
2015	1	Tanners 3	Retirement	-195	-195
2016	1	Rockport 1	Turbine Steam Path Upgrade + FGD	0	0
2016	1	Rockport 1	Seasonal Derate Removal	10	9
2020	1	Rockport 2	Turbine Steam Path Upgrade	35	30
2025	1	Tanners 4	Retirement	-500	-500
				-940	-947

3. Fuel Inventory and Procurement Practices.

a. General

The generating units of I&M and the other AEP System-East Zone operating companies, which are predominantly coal-fired, 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.

The first long-term contract between I&M and Peabody COALSALES, LLC formerly known as the Rochelle Coal Company that began in October 1989 and was scheduled to expire at the end of 2004 has been extended by I&M and Peabody Energy Corporation with annual base tonnages scheduled through the term of the agreement. The second long-term agreement is in effect with Peabody COALSALES, LLC with deliveries of coal that commenced in January 2005 and continues under the terms of the agreement. 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 and the AEP System-East Zone operating companies 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 2012 through 2021 are displayed in Exhibit 1 of the Confidential Supplement.

4. Capacity Acquisitions and Dispositions

As part of its resource planning process, AEP continues to investigate the viability of placing indicative offers on additional utility or IPP-owned natural gas peaking and combined cycle facilities. On September 19, 2007, AEP completed the purchase of a natural gas-fired power plant under construction near Dresden, Ohio, from Dresden Energy LLC, a subsidiary of Dominion. With an expected Commercial Operation date in early 2012, Dresden will be a nominal 625 MW natural gas-fired combined-cycle plant owned by APCo.

Another important initial process within this 2011 IRP cycle was the establishment of a long-term view of disposition alternatives facing older, smaller currently uncontrolled coal-steam units in the I&M and AEP System-East fleet. Prior "Unit Disposition" analyses identified aging I&M and AEP-East generating assets consisting of a total of 26 units (including 4 I&M units) with a PJM (summer) rating of 5,348 MW (including 985 MW for I&M).

<u>I&M</u>

- Tanners Creek Units 1-3 (485 MW) IN
- Tanners Creek Units 4 (500 MW) IN

<u>APCo</u>

- Clinch River Units 1-3 (690 MW) VA
- Glen Lyn Unit 5 (90 MW) and Unit 6 (235 MW) VA
- Kanawha River Units 1 & 2 (400 MW) WV
- Sporn Units 1 & 3 (290 MW) WV

<u>AEP-Ohio</u>

- Conesville Unit 3 (165 MW) OH
- Kammer Units 1-3 (600 MW) WV
- Muskingum River Units 1 & 3 (395 MW) OH
- Muskingum River Units 2 & 4 (395 MW) OH
- Picway Unit 5 (95 MW) OH
- Sporn Units 2 & 4 (290 MW) WV
- Sporn Unit 5 (440 MW) WV

<u>KPCo</u>

- Big Sandy Unit 1 (278 MW) KY

Among this group of units are several that were impacted by the Consent Decree from the previously settled NSR litigation. 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/RR"), are:

- Conesville Unit 3, by December 31, 2012
- Sporn Unit 5, by December 31, 2013
- Muskingum River Units 1-4, by December 31, 2015
- A total of 600 MW from Sporn 1-4, Clinch River 1-3, Tanners Creek 1-3, or Kammer 1-3, by December 31, 2018.

Prior IRP cycle evaluations of unit conditions and related criteria laid the groundwork for purposes of determining a potential sequence of unit retirements for subsequent resource planning purposes. This sequencing also assumed a "staggered and extended" implementation of then-anticipated U.S. EPA rulemaking. Those dates typically had extended at least through this decade (12/2019).

However, with the new implementation dates contained in the recently issued CSAPR, as well as EGU MACT and CCR rules proposed in 2011, such sequencing now may not be achievable. All units will need to be controlled under the proposed EGU MACT rule by January 2015 (or, potentially, January 2016 should a one-year extension be granted for that purpose). This new rule may have established the retirement date for each uncontrolled unit, including Tanners Creek 1-3. Those units that would be able to operate with limited investment, such as I&M's Tanners Creek 4, will not be retired to comply with these rules.

5. Projected Capacity Position

Exhibits 5-3 and 5-4 present the I&M and AEP System-East Zone capacity positions with the specified retirements versus the projected PJM reserve margin requirement. The impact of any new non-contracted/announced capacity builds and market purchases are shown as "New Fossil Fuel Generation (MW)" and "Annual Purchases (MW)". The impact of additional Renewable Purchase Power Agreements (REPA) that would be required to minimally achieve mandated renewable energy (largely, wind) resources are shown as "New Renewable Generation (MW)". Based on the assumptions mentioned, the capacity of the AEP System-East Zone would move to a deficit position beginning in 2014 without these additions whereas I&M has sufficient capacity until Tanners Creek 4 retires in 2024.

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, intermediate, and baseload capacity needs. To reduce the number of modeling permutations in *Strategist*®, 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 the AEP System-East Zone are presented in Exhibit 3 of the Confidential Supplement. It is also important to note that AEP's planning position for its East Zone is to take advantage of market opportunities when economical, both in the form of limited-term bilateral capacity purchases from non-affiliate sources and by way of available, 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. 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 3 of the Confidential Supplement, numerous new-build generating technologies were considered to address this coming need to construct new capacity. However, in an attempt to reduce the problem size within the comprehensive *Strategist*® 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 *Strategist*®. Screening curves for the peaking capacity types are shown on Exhibit 5-5. 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 intermediate capacity in Exhibit 5-6 and baseload capacity in Exhibits 5-7 and 5-8. A comparison of the best-in-class technologies is presented in Exhibit 5-9.

The best of class technology determined by this screening process was taken forward to the *Strategist*® 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.

3. Coal Based Options

Pulverized Coal (PC) plants are the workhorse of the U.S. electric power generation industry. In a PC plant, the coal is ground into fine particles that are blown into a furnace where combustion takes place. The heat from the combustion of coal is used to generate steam to supply a steam turbine that drives a generator to produce electricity. Major by-products of combustion include SO_2, NO_X, CO_2, and ash, as well as various forms of elements in the coal ash including mercury (Hg). The ash byproduct is often used in concrete, paint, and plastic applications.

Steam cycle thermodynamics for the pulverized coal-fired units–which determines the efficiency of generating electricity– falls into one of two categories, subcritical or supercritical. Subcritical operating conditions are generally accepted to be at up to 2,400 psig/1,000°F superheated steam, with a single or double reheat systems to 1,000°F, while supercritical steam cycles typically operate at up to 3,600 psig, with 1,000°F -1,050°F main steam and reheat steam temperatures. AEP has recognized the benefits of the supercritical design for many years. All eighteen of the units in the AEP-East system built since 1964 have utilized the supercritical design, including APCo's Mountaineer Plant and Amos units 1, 2, and 3.

There have been advances in the supercritical design over the years, and there are now commercial units operating at or above 3,600 psig and >1,100°F steam temperatures, known as an ultra supercritical (USC) design. AEP's Turk plant, which is currently under construction in Arkansas, is a new USC design.

The overall efficiency of the supercritical design is higher than the subcritical design by approximately 4% and USC design efficiency is higher than a supercritical design by approximately 4 to 5%. Additionally, the new variable pressure ultra supercritical units are projected to have an overall efficiency improvement throughout the entire load range, not just at full load conditions.

Given the long time-horizons of most resource planning exercises, IRP processes must be able to consider new technologies such as Integrated Gasification Combined Cycle (IGCC). The assessment of such technologies is based on cost and performance estimates from commonly cited public sources, consortia where AEP is actively engaged, and vendor relationships, as well as AEP's own experience and expertise.

IGCC is of particular interest to AEP in light of the abundance, accessibility, and affordability of high rank coals for the company–particularly in its eastern zone. IGCC technology with carbon capture has the potential to achieve the environmental benefits closer to those of a natural gas-fired plant, and thermal performance closer to that of a combined cycle, yet with the low fuel cost associated with coal. The coal gasification process appears well-positioned for integration of ultimate carbon capture and storage technologies, which will be a critical measure in any future mitigation of greenhouse gas emissions associated with the generation of electricity. As an additional observation, the small number of IGCC equipment suppliers and few utility-scale facilities in commercial operations worldwide means a large share of technology and performance risk falls on owners, although the on-going collaboration with technology developers may mitigate some of this risk.

The IGCC process employs a gasifier in which coal is partially combusted with oxygen and steam to form what is commonly called "syngas"–a combination of carbon monoxide, methane, and hydrogen. The syngas produced by the gasifier then is cleaned to remove the particulate and sulfur compounds. Sulfur is converted to hydrogen sulfide and ash is converted into glassy slag. Mercury is removed in a bed of activated carbon. The syngas then is fired in a gas turbine. The hot exhaust from the gas turbine passes to a heat recovery steam generator (HRSG), where it produces steam that drives a steam turbine as would a natural gas-fired combined cycle unit.

IGCC enjoys comparable thermal efficiencies to USC-PC. Its ability to utilize a wide variety of coals and other fuels positions it extremely well to address the challenges of maintaining an adequate baseload capability with efficient, low-emitting, low-variable cost generating technology. Further, IGCC is in a unique position to be pre-positioned for carbon capture as, unlike PC technologies, it has the ability to perform such capture on a "pre-combustion" basis. It is believed that this will ultimately lead to improved net thermal efficiency than would be required by PC technology utilizing post-combustion carbon capture technology.

Another baseload fossil-fueled option, a Circulating Fluidized Bed Combustion (CFB) plant, is similar to a PC plant except that the coal is crushed rather than pulverized, and the coal is combusted in a reaction chamber rather than the furnace of a PC boiler. A CFB boiler is capable of burning bituminous and sub-bituminous coal plus a wide range of fuels that cannot be accommodated by PC designs. These fuels include, coal waste, lignite, petroleum coke, a variety of waste fuels, and biomass. Units are sometimes designed to fire using several fuels, which emphasizes this technology's major advantage: fuel flexibility. Coal is combusted in a hot bed of sorbent particles that are suspended in motion (fluidized) by combustion air blown in from below through a series of nozzles. CFB boilers operate at lower temperatures than pulverized coal-fired boilers. The energy conversion efficiency of CFB plants tends to be slightly lower than that of pulverized coal-fired counterparts of the same size and steam conditions because of higher excess air and auxiliary power requirements.

CFB boilers capitalize on the unique characteristics of fluidization to control the combustion process, minimize NO_X formation, and capture SO_2 in situ. Specifically, SO_2 is captured during the combustion process by limestone being fed into the bed of hot particles that are fluidized by the combustion air blown in from below. The limestone is converted into free lime, which reacts with the SO_2. Historically, the largest CFB unit in operation is 320 MW, but designs for units up to 600 MW have been developed by three of the major CFB suppliers. In July of 2009, the Lagisza Power Plant in Poland began commercial operations; the plant is the largest and first supercritical CFB in operation and is rated at 460 MW. AEP has no commercial operating experience with generation utilizing circulating fluidized bed boilers but is familiar with the technology through prior research, including the Tidd pressurized fluidized bed demonstration project. Commercial CFB units utilize a subcritical steam cycle, resulting in a lower thermal efficiency.

4. Nuclear

Although new reactor designs and ongoing improvements in safety systems make nuclear power an increasingly viable option as a new-build alternative due to it being an emission-free power source, concerns about public acceptance/permitting (especially since the recent disaster in Japan), spent nuclear fuel storage, lead-time, high capital costs, and the risk of cost overruns continue to temper its consideration. For these reasons, among others, AEP does not currently view new nuclear capability as a viable option to meet the capacity resource needs of AEP System-East Zone within this forecast period (2012-2031). However, both the economic and political viability of nuclear power and energy will continue to be explored given:

- I&M and AEP-East zone's ultimate need for baseload capacity;
- the cost and performance uncertainty surrounding the advancement and commercialization of clean coal technology, notably, IGCC;
- the cost and performance uncertainty of carbon capture and storage technology;
- the continued push to address AEP's carbon footprint and the mitigating impact additional nuclear power clearly would have in that regard; and
- the prospect of a federal Clean Energy Standard that would effectively embrace the introduction of nuclear generation.

Growth in U.S. nuclear generation since 1977 has been primarily achieved through "uprating" – the practice of increasing capacity at an existing nuclear power plant. As of January 2010, the NRC had approved 124 uprates totaling 5,726 MW of capacity. That amount is equivalent to adding another five-to-six conventional-sized nuclear reactors to the electricity supply portfolio.

5. 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 one of 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 period 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.

6. 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, however, inexpensive to purchase, compact, and simple to operate.

7. 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.

8. Wind

Wind is currently the fastest growing form of electricity generation in the world. 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 40,000 MW of wind online in the United States as of February 2011. 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 from the perspective of both the existing wind resource and its proximity to a transmission system with available capacity.

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 AEP-East due largely, however, to subsidies, such as the federal production tax credit as well as consideration given to REC values, anticipated rising fuel costs or future carbon costs.

A drawback of wind is that it represents a variable source of power in most non-coastal locales, with capacity factors ranging from 30 to 45 percent; thus its life-cycle cost ($/MWh), excluding subsidies, is typically higher than the marginal (avoided) cost of energy, in spite of wind's zero dollar fuel cost. 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 buildout of EHV transmission to optimally integrate large additions of wind into the grid.

9. 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 (100 MW) 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 are distributed throughout the grid. In AEP-East, solar has applications as both large scale and distributed generation. The appeal of solar is broad and recent legislation in Ohio has made its pursuit mandatory subject to rate impacts, beginning in 2009. Solar photovoltaics are represented in this IRP based on this solar requirement being met in

Ohio. However, the amounts of solar prescribed in the law, while substantial, will not have a significant effect on the timing or amount of other supply assets within a twenty-year forecast period.

6) ENVIRONMENTAL COMPLIANCE

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 with the AEP system. AEP's goal in the development of the integrated resource and compliance plan is to develop a comprehensive plan that not only allows AEP and I&M to meet the future resource needs of the Company in a reliable manner, but also to meet increasingly more 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), which totaled approximately 539,702 tons of material in 2010. 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 understand any releases to the groundwater, and stormwater runoff collection and treatment system, with discharge 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 2010, CCBs comprised of fly ash, bottom ash, and boiler slag, generated at the plant totaled about 152,881 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 landfill at Tanners Creek was recently expanded, with the intention of allowing the landfill to continue accepting CCBs at Tanners Creek for another 10 years.

The US Environmental Protection Agency (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 Coal Combustion Residuals Rule (CCR) in June 2010 and a final rule is expected to be available by the end of 2012. Discussion of this rule is available in more detail in part L 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 for hydros include trash, solvents, and hydraulic fluid, which are recycled or properly disposed 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 hydro facilities, hazardous waste is transferred to the Twin Branch hydro 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 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 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 Indiana State Implementation Plan (SIP). Other applicable requirements include those related to the CSAPR 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 hazardous air pollutants (HAPS) and greenhouse gases (GHG).

Potential air emissions at the Rockport Plant are reduced through the use of electrostatic precipitators (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 the 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 Interim Allowance Agreement, 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 or purchased to 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 nitrogen oxides (NO_x). In addition, evolving environmental regulations will likely require unit-specific, rather than system-wide, solutions. For these reasons, the IAA will likely be terminated, as described in Section 1.

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 Clean Air Act Amendments (CAAA) 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 sulfur dioxide (SO_2) and nitrogen oxides (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 employed 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 NO_x Budget Program State Implementation Plan (SIP) Call

In addition to the Title IV NO_x reduction program, the Indiana NO_x Budget Program State Implementation Plan (SIP) Call was designed to reduce the interstate transport of NOx 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, 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 electric generating units (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 extensive 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 was planned on being 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.

4. New Source Review 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.

The 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. These annual caps are displayed in Figure 6-1 and 6-2.

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 6-1 New Source Review (NSR) Consent Decree Annual NO_x Caps

NSR Consent Decree Annual SO_2 Cap

Calendar Year	Annual Tonnage Limitations for SO_2
2010	450,000
2011	450,000
2012	420,000
2013	350,000
2014	340,000
2015	275,000
2016	260,000
2017	235,000
2018	184,000
2019, and each year thereafter	174,000

Figure 6-2 New Source Review (NSR) Consent Decree Annual SO_2 Caps

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.

5. Cross State Air Pollution Rule (CSAPR)

The EPA proposed and published a replacement for the Clean Air Interstate Rule (CAIR) in the form of the Clean Air Transport Rule (CATR) on August 2, 2010 and finalized that rule on July 7, 2011 as the CSAPR. The CSAPR is more stringent in its final form than as the CATR and CAIR.

Twenty-eight (28) states are covered by the new rule. All states in which AEP owns and/or operates power plants are included in at least one of the CSAPR programs. Indiana, Kentucky, Michigan, Ohio, Texas, Virginia and West Virginia fall under all the programs regulating annual SO_2, and both annual and seasonal NO_x. Arkansas, Louisiana and Oklahoma fall under the CSAPR seasonal NO_x program only.

CSAPR has an initial compliance phase deadline for the SO_2 and NO_X programs beginning on January 1, 2012 ("Phase 1"). A second, more stringent compliance phase for SO_2 emissions limits (only) will take effect beginning on January 1, 2014 ("Phase 2"). Prescribed Annual and Seasonal NO_x emission limits, however, will remain approximately at "Phase 1" levels in 2014. Figure 6-3 displays the unit specific allocations to impact I&M generating facilities under each phase.

In October 2011, the Federal EPA released a supplemental proposed rule revising portions of the final CSAPR. The proposed rule would correct errors in unit-specific assumptions and make available additional allowances in ten states, including Louisiana and Texas, and provide additional allowances for the new unit set aside in Arkansas. In addition, the proposed rule would amend the allowance trading assurance provisions which restrict interstate trading of allowances, making them effective January 1, 2014 instead of January 1, 2012.

CSAPR SO_2 and NO_x Allowances Allocated to Indiana Michigan Power Company[5]

	SO_2		Annual NO_x		Ozone Season NO_x	
	2012	**2014**	**2012**	**2014**	**2012**	**2014**
Rockport Unit 1	21,292	11,776	7,883	7,788	3,316	3,265
Rockport Unit 2	19,923	11,019	7,376	7,288	3,148	3,100
Tanners Creek Unit 1	1,980	1,095	733	724	295	290
Tanners Creek Unit 2	1,920	1,062	711	702	311	307
Tanners Creek Unit 3	2,634	1,457	975	963	424	418
Tanners Creek Unit 4	5,819	3,219	2,154	2,129	1,058	1,042

Figure 6-3 Cross State Air Pollution Rule (CSAPR) Allocated I&M CSAPR SO_2 and NO_x Allowances

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. Coal Combustion Residuals (CCR) Rule

The EPA proposed this rule in June 2010, with a final rulemaking anticipated in late 2012, to address the management of residual byproducts from the combustion of coal in power plants (coal ash) and captured by emission control technologies. 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 may require the conversion of most “wet” ash impoundments to “dry” ash landfills, the relining or closing

[5] Note: On Oct. 6, 2010 EPA announced proposed revisions to CSAPR that would result in slight modifications to the SO_2 and NO_X budgets. These revisions have not been finalized and are not included in the table above.

of any remaining ash impoundment ponds, and the construction of additional waste water treatment facilities by approximately January 1, 2018. Even if these residual materials are categorized as "Subtitle D," or non-hazardous materials[6]—each and every coal unit in the AEP fleet, including all APCo coal facilities, would require plant modifications and capital expenditures to address CCR requirements.

2. EGU MACT Rule

To replace the federal court vacated Clean Air Mercury Rule (CAMR), the EPA proposed a rule in March 2011 designed to reduce and regulate emissions of mercury and other toxic metals and acid gases at electric generating units by using maximum achievable control technology (EGU MACT) emission standards. The Clean Air Act (CAA) requires compliance within 3 years after the issuance of this final rulemaking, which in this case, would be at approximately the end of 2014, but also provides a one year extension which could potentially delay implementation to the end of 2015 if specific criteria are satisfied. The proposed EGU MACT emission limits will require the installation of emission control equipment, such as flue gas desulfurization (FGD) selective catalytic reduction (SCR) technology, dry sorbent injection (DSI), and activated carbon injection (ACI) on coal-fired utility units, as well as the performance of upgrades to some existing emission control systems in order to achieve the required emission rates. EPA is expected to finalize the rule by December 16, 2011.

In anticipation of these requirements, AEP and I&M successfully tested the ability of activated carbon injection (ACI) to mitigate mercury emissions at the Rockport plant

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[6] As set forth under the current Resource Conservation and Recovery Act (RCRA)

in the spring of 2006. In February of 2009, after already having had 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.

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 mid-2012. 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 Tanners Creek units and DC 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. Greenhouse Gas (GHG) Regulations

For many years, the potential for requirements to reduce GHG gas emissions, including carbon dioxide (CO_2), has been one of the most significant sustainability issues facing APCo and AEP. AEP and I&M have relied on coal for a number of reasons: coal provides an affordable, reliable, and sustainable source of energy; AEP and I&M are located in close proximity to the nation's coal supply; AEP and I&M have a legacy in coal-fired generation as demonstrated by the huge investments made and the engineering and operational expertise developed over more than a century. As a result, coal is expected to remain a key part of AEP's fuel portfolio for many years to come. AEP is one of the largest consumers of coal in the Western Hemisphere and coal currently accounts is the major portion of the generation portfolio.

AEP supports a legislative approach to resolve the GHG issue rather than a regulatory approach. Without a regulatory driver, an investment to develop GHG control technologies is too significant to justify the capital cost and risk. Given that there are currently no cost-effective post combustion control technologies or best achievable retrofit technology (BART) available for GHG emissions, future standards are anticipated to focus on energy efficiency opportunities. Such GHG legislation from Congress is not expected in the next few years.

G. I&M Environmental Compliance

This 2011 IRP considered final and proposed EPA regulations. In addition, the IRP development process assumed there will be future legislation to control 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.

Major near-term challenges relate to the development and implementation of a new compliance plan to comply with stringent implementation time periods for CSAPR (beginning January 2012) and for the EGU MACT rule (expected beginning January

2015). For instance, AEP has engineered and constructed nine FGD systems over the past decade. This experience indicates that approximately 52-56 months is required to permit, design and engineer, construct and commission such a system. This timeframe approaches five years or more when also considering any up-front regulatory (*i.e.*, "need") approvals required.

Also complicating the lack of flexibility on compliance timeframes is the fact that EPA established more stringent SO_2 and NO_x state (emission) allowance budgets in the final CSAPR than it proposed in August 2010. AEP and I&M have evaluated possible emission mitigation strategies for complying with CSAPR, including including:

- low-cost and quick-to-install environmental retrofits options;
- fuel switching options (to lower sulfur-content coals and repowering to natural gas); and
- dispatch optimization options (including the possibility of unit generation curtailments)

Any historical allowances from CAIR will expire at the end of 2011, and be replaced by the allowance market created under the CSAPR. If it is economical and the market supply is available, I&M will purchase allowances for emissions above their allocations under CSAPR.

I&M is currently obligated by the NSR Consent Decree to install SO_2 and NO_x controls at Rockport Unit 1 by the end of 2017 and at Rockport Unit 2 by the end of 2019. The CSAPR and EGU MACT Rule will accelerate that requirement significantly. I&M analysis of the EPA's final CSAPR indicates that, at a minimum, one unit at the Rockport Plant will be required to have an FGD installed by January 1, 2012 to avoid having to curtail generation. Under the proposed EGU MACT, I&M would be required to install additional environmental controls at the Rockport Plant by January 1, 2015 or one year later if the EPA grants a compliance extension. The short compliance deadline required by the proposed EGU MACT Rule is clearly a challenge for implementing additional emission control retrofit projects at Rockport in a timely manner.

On August 1, 2011, I&M filed 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. It is also indicated that it will be necessary to significantly curtail operations at the Rockport and Tanners Creek facilities to limit emissions for compliance with the CSAPR until environmental controls can be installed. In addition to the environmental projects at Rockport, the retirements of Tanners Creek units 1 through 3 will accelerate to December 31, 2014.

In summary, AEP has conducted a series of reviews to evaluate the cost effectiveness of its air emissions control strategy in complying with existing and anticipated environmental regulations. The economic analyses performed indicate that an FGD and SCR at one of the Rockport units, as well as the accelerated retirement of Tanners Creek Units 1 through 3, are part of a least cost compliance plan. 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 2 of the Confidential Supplement.

7) ELECTRIC TRANSMISSION FORECAST

7. Electric Transmission Forecast

A. General Description (170 IAC 4-7-4(12))

The eastern Transmission System (eastern zone) consists of the transmission facilities of the seven eastern AEP operating companies. 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 8,800 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 eastern Transmission System that takes transmission service under the PJM open access transmission tariff.

The eastern Transmission System is the most integrated transmission system in the Eastern Interconnection. These interconnections provide an electric pathway to facilitate access to off-system resources and serve as a delivery mechanism to adjacent companies. The entire eastern Transmission System is located within the Reliability*First* (RFC) Regional Entity. On October 1, 2004, AEP's eastern zone joined the PJM Regional Transmission Organization, and now participates in the PJM markets.

As a result of the 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 redispatch 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 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.

AEP's eastern Transmission System assets are aging. Therefore, in order to maintain reliability, significant investments will have to be made over the next ten years.

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 eastern AEP 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.

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 System-East 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 retirement of Conesville units 1 and 2 in 2006 and the anticipated retirement of Conesville Unit 3 in 2012 will result in the need for power to be transmitted over a longer distance into the Columbus, Ohio metro area. In addition, these retirements will result in the loss of dynamic voltage regulation. Since there is very little baseload generation in central Ohio, these retirements could be significant. The retirement of these units could require the addition of dynamic reactive compensation such as a Static VAR Compensator (SVC) device within the Columbus metro area. 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.

- 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 4) and these planning criteria are posted on the AEP website.[7] 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

[7] http://www.aep.com/about/codeofconduct/OASIS/TransmissionStudies/GuideLines/2011%20AEP%20PJM%20FERC%20715_Final_Part%204.pdf

practice, transmission reliability studies are conducted routinely for seasonal, near term, and long-term horizons to assess the anticipated performance of the transmission system. 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.

E. Evaluation of Other Factors (170 IAC 4-7-4(14); 4-7-6(a) (6) (A-C); 4-7-6(d) (1))

As a member of PJM, and in compliance with the 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 40 active queue positions within Indiana totaling approximately 9,800 MW (nameplate), including projects that are either in various stages of study (28 projects), under construction (4 projects), or in-service (8 projects). Of these 40 active queue positions, 34 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 System-East Zone 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 AEP 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 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, 2011 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 4 of the Confidential Supplement.

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[8] 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.

  2012: $0.04 million

  2013: $0.04 million

- Lincoln Breaker Upgrade: PJM identified the Lincoln 138 kV breaker D as being over dutied and over loaded under certain contingency conditions. AEP is proposing to replace Lincoln 138 kV breaker D, the risers and cross bus sections of the Lincoln – Allen 138 kV circuit at Lincoln station.

  2012: $0.5 million

- Industrial Park – McKinley Upgrades: PJM identified an overload on the McKinley – Industrial Park 138 kV circuit. The proposed solution is to replace 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.

  2012: $75,000

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[8] Please note that cash flows are approximated.

2013: $75,000

- 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 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.

  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.

  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.

  2012: $2.5 million

  2013: $2.0 million

- Local Sag Studies: PJM identified overloads on several 138 kV lines that require sag and structure analysis to increase the emergency operating temperature of these lines. The lines being 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

  2012: $0.8 million

  2013: $0.8 million

- Strawton Wind Farm: PJM IPP project U3-002 has a signed Interconnection Service Agreement (ISA) and is scheduled to be operational by the end of 2012. This wind farm will connect to the Deer Creek – Fisher Body – Mullin 138 kV line. In addition to the wind farm connection, station improvements will be made at Mullin station and at Fisher Body station. Cost information provided reflects only the dollars to be spent by AEP.

  2011: $0.1 million

  2012: $1.0 million

The following provides an update for each of the transmission projects provided in the 2009 IRP. All of the projects have been completed and are now in-service.

- Woods Road Station Project: Woods Road station was established to move 34.5 kV load at Gump Station near Huntertown, Indiana to a new 138 kV station in an attempt to avoid overload conditions on the 34.5 kV system and to improve reliability for the customers.

- Brevini Project: A new customer in Muncie, Indiana had requested service to its facilities that manufactures and tests gearboxes for wind turbines. The projected initial load of 5 MW could be accommodated on the aging 34.5 kV sub-transmission system or existing 12 kV facilities in the area. To reliably serve the load, and to meet the future needs of the area, a radial 5.9 mile, 138 kV line was constructed, with future plans to network the line.

- Twin Branch Area Improvements: The 450 MVA 345/138 kV transformer at Twin Branch Station was projected to overload under several contingencies. A project was initiated in 2007 to replace the existing transformer with a larger 675 MVA 345/138 kV transformer.

- Western Fort Wayne Area Improvements: The Western Fort Wayne area was expected to reach a demand of 190 MVA in 2008. The area transmission facilities were expected to experience thermal overloads and heavy loading under single contingencies. To mitigate the thermal overloads, a new 69 kV line from the Industrial Park Station to the Hadley Station was proposed. The project was initially projected to go in-service in 2008, but due to logistics and material acquisition issues; the project went in-service in 2009.

- Meadow Lake Station: A 200 MW wind farm had requested interconnection to I&M's 345 kV transmission system in Chalmers County, Indiana. The interconnection required construction of a new 345 kV switching station at the developer's expense. The new switching station went in-service in October 2009.

- Wallen Relocation Project: The Indiana Department of Transportation relocated sections of Indiana Route 3 which required relocation of 34.5 kV facilities at I&M's Wallen Station. Significant portions of the relocation projects were reimbursable from the Department of Transportation. The Wallen Relocation Project went in-service in 2009.

- Herbert Monroe Delivery Point: A new switching station was established to serve Paulding Putnam Electric Cooperative Herbert Monroe delivery point at 138 kV.

8) SELECTION OF THE RESOURCE PLAN

8. Selection of the Resource Plan (170 IAC 4-7-8)

A. Modeling Approach

1. The *Strategist*® Model

The *Strategist*® optimization model served as the empirical calculation basis from which the I&M-specific and AEP-East capacity requirements evaluations were examined and recommendations were made. As will be identified, as part of this iterative process, *Strategist*® offers unique portfolios of resource options that can be assessed not only from a discrete, revenue requirement basis, but also for purposes of performing additional risk analysis outside the tool.

As its objective function, *Strategist*® determines the regulatory least-cost resource mix for the generation system being assessed. The solution is bounded by a user-defined set of resource technologies, commodity pricing, and prescribed sets of constraints.

Strategist® develops a discrete macro (zone-specific) least-cost resource mix for a system by incorporating a variety of expansion planning assumptions including:

- Resource alternative characteristics (e.g. capital cost, construction period, project life.)
- Operating parameters (e.g. capacity ratings, heat rates, outage rates, emission effluent rates, unit minimum downturn levels, must-run status, etc.) of existing and new units
- Unit disposition (retirement / mothballing)
- Delivered fuel prices
- Prices of external market energy and capacity as well as SO_2, NO_X, and CO_2 emission allowances
- Reliability constraints (in this study, minimum reserve margin targets)

- Emission limits and environmental compliance options

These assumptions, and others, are considered in developing an integrated plan that best fits the utility system being analyzed. *Strategist®* does not develop a full regulatory cost-of-service (COS) profile. Rather, it typically considers only supply and demand resource COS changes from plan-to-plan, not fixed, embedded costs associated with existing generating capacity 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.

Specifically, *Strategist®* includes and recognizes in its incremental, largely generation revenue requirement output profile:

- Fixed costs of capacity additions, i.e. carrying charges on incremental capacity additions (based on an I&M-specific, or weighted average AEP System cost of capital), and fixed O&M.
- Fixed costs of any capacity purchases.
- Program costs of (incremental) DR/EE/IVVC alternatives.
- Variable costs associated with I&M's or the entire fleet of AEP-East's new and existing generating units (developed using the model's probabilistic unit dispatch optimization engine). This includes fuel, purchased energy, market replacement cost of emission allowances, and variable O&M costs.
- Market revenues from external energy transactions (i.e., Off-System Sales) are netted against these costs under this ratemaking/revenue requirement format.

In the PROVIEW module of *Strategist®*, the least-cost expansion plan, measured by the Cumulative Present Worth of Revenue Requirements (CPW), is empirically formulated from potentially hundreds of thousands of possible resource alternative combinations created by the module's chronological dynamic programming algorithm. On an annual basis, each capacity resource alternative combination that satisfies various user-defined constraints (to be discussed below) is considered to be a "feasible state" and is saved by the program for consideration in following years. As the years progress, the previous years' feasible states are used as starting points for the addition of more resources that can be used to meet the current year's minimum reserve requirement. As the need for additional capacity on the system increases, the number of possible combinations and the number of feasible states increases exponentially with the number of resource alternatives being considered.

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 2012-2040 planning period.

2. Load & Demand Forecast

The internal load and peak demand forecast is based on the approved 2011 AEP System-East Zone load forecast issued in February 2011.

3. Capacity Modeling Constraints

Since the model's algorithm has the potential for creating such a vast number of alternative combinations and feasible states, it can become an extremely large computational and data storage problem, if not constrained in some manner. The *Strategist®* model includes a number of input variables specifically designed to allow the user to further limit or constrain the size of the problem. There were numerous other known physical and economic issues that needed to be considered and, effectively, "constrained" during the modeling of the long-term capacity needs so as to reduce the problem size within the tool.

- Maintain a PJM-required minimum reserve margin of roughly 15.3% per year.

- Under the terms of the NSR Consent Decree, I&M and AEP agreed to annual SO_2 and NO_X emission limits for its fleet of 16 coal-fueled power plants in Indiana, Kentucky, Ohio, Virginia and West Virginia. These emission limits were met by adjusting the dispatch order of these units during the *Strategist*® economic dispatch modeling.

- In addition to meeting NSR consent Decree emission limits, the SO_2 and NO_X allocations/limits defined under the recently finalized CSAPR for I&M's Indiana and Michigan-domiciled generating units were also met during the *Strategist*® modeling.

- The initial period for consideration of new generation additions was assumed to, minimally, not precede the PJM 2014/15 forward planning year due to AEP—on behalf of its eastern operating affiliates, including I&M—having already committed sufficient UCAP resources. Moreover, considering the uncertainty surrounding the ultimate status and implications of both:

    - the ultimate status or make-up of the AEP Interconnection Agreement; and

    - the ultimate status and impact of additional emerging EPA rulemaking, namely EGU MACT;

- The restriction for consideration of new generation additions was further extended 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 *Strategist®* 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.

- *Baseload* capacity burning eastern bituminous coals was modeled. The potential for future legislation limiting CO_2 emissions was considered in selecting the solid fuel baseload capacity alternatives. Two solid fuel alternatives were made available to the model:

    - 624 MW Ultra Supercritical PC unit (summer rating of 612 MW) where the unit is installed with chilled ammonia carbon capture and storage (CCS) technology that would capture 90% of the unit’s CO_2 emissions. This option could be added beginning in 2020.

    - 637 MW Integrated Gasification Combined Cycle (IGCC) “F” Class unit. This alternative could be added by *Strategist®* beginning in 2020 and;

    In addition, beginning in the year 2022:

    - *Strategist®* could select an 800 MW (~50%) share of a 1,606 MW nuclear, Mitsubishi Heavy Industries (MHI) Advanced Pressurized Water Reactor (771 MW summer)

In order to maintain a balance between peaking, intermediate and baseload capacity resources, only seven Combustion Turbine (CT) units could be added in any year. If the addition of seven CTs was not sufficient to meet reliability requirements in a particular year, the model was required to add either intermediate and/or baseload capacity to meet the reliability targets.

4. Commodity Pricing Scenarios

Three commodity pricing scenarios were developed by AEPSC to enable *Strategist*® to construct resource plans under various long-term pricing conditions. The long-term power sector suite of commodity forecasts are derived from a proprietary model known as *Aurora*^{XMP}. *Aurora*^{XMP} is a long-term fundamental production-costing tool developed by EPIS that is driven by sophisticated 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 *Strategist*® are: a “base” view or, “Fleet Transition – Carbon Adjusted,” as well as two sensitivity views including, “Fleet Transition,” and “Lower Band.” The scenarios are described below with the results shown in Exhibits 8-1 to 8-5.

4a. Fleet Transition-Carbon Adjusted

This represents AEP's current consensus view of all drivers to the development of North American regional power prices. It recognizes relatively lower natural gas prices and increasing natural gas price elasticity - despite increasing consumption from domestic power plants. This phenomenon largely being a function of significant natural gas supplies from emerging shale gas extraction efforts. A major criterion of this “base” scenario reflects AEP managements view that substantive national CO_2 legislation and its attendant carbon pricing will not be in place until the year 2022.

4b. Fleet Transition

Largely the same basis as the above view other than the implementation of a CO_2/carbon pricing regime is assumed to be as early as 2017.

4c. Lower Band

This case should best be viewed as low natural gas/energy price "sensitivity" to the Fleet Transition and Fleet Transition-Carbon Adjusted scenarios. In the near term, Lower Band natural gas prices track the Fleet Transition but in the longer term, natural gas prices represent the even more significant infusion of shale gas. From a statistical perspective this long-term pricing scenario represents approximately a negative one (-1) standard deviation from the “Fleet Transition” scenarios and illustrates the effects of Coal-to-gas substitution at such plausibly lower gas prices. Like the Fleet Transition scenarios, CO_2 mitigation/pricing is assumed to start as early as 2017.

C. Modeling Results (170 IAC 4-7-8(2) and 4-7-8(6))

1. Base Results by Pricing Scenario

Given the three fundamental pricing scenarios developed by AEPSC as listed in the previous section, as well as the modeling constraints and certain planning commitments, *Strategist*® modeling was used to develop the initial plans identified in Exhibits 8-6 and 8-7. With regard to these exhibits, because Renewable assets and a base level of incremental DSM are included in all portfolios, *Strategist*® did not represent them as incremental resources within these comparative plan views.

2. Observations: Needs Assessment

Some I&M specific observations drawn from the initial *Strategist*® profiles reflected on Exhibit 8-6 include:

- No new capacity is required until Tanners Creek 4 is retired, and
- The optimal replacement technology for Tanners Creek 4 is a NGCC.

3. Strategic Portfolio Creation & Evaluation

For this IRP, two views of I&M were considered. First, I&M was modeled as a stand-alone entity in PJM. This recognizes the potential that the AEP-Pool could be either materially modified or terminated over the course of the IRP planning cycle and that no AEP-East companies would have any obligation to provide capacity or energy to any other AEP-East company. A second view assumes the AEP Pool remains in place and the AEP Pool companies would be allocated capacity resources based on their position within the AEP Pool. In this view, optimized portfolios are created for the AEP-East System, which could result in a different amount of capacity being assigned to the AEP Pool companies. The I&M capacity plan is the same under either a "AEP Pool" or "No AEP Pool" scenario. That is, if the AEP Pool remains in place, the only new capacity resource assigned to I&M is a NGCC in 2025, which is the same as under the I&M "No AEP Pool" scenario.

4. I&M Strategic Portfolios

Strategic approaches that were considered when constructing the underlying I&M ('stand-alone') system resource portfolios analyzed include:

- "Base" Plan:

    - Retrofit Rockport 1 & 2, and Tanners Creek 4 to be compliant with the proposed EGU MACT and CCR rules, as well as NSR Consent Decree obligations. Retire Tanners Creek 1, 2 & 3 by December 31, 2014 so as not to incur retrofit costs required by the EGU MACT rule. Retire Tanners Creek 4 when it reaches 60 years of life, in 2025, and replace it with a natural gas combined cycle (NGCC) plant.

- "Gas" Plan:
    - Same as the Base plan, except retire Tanners Creek 4 by 2015 and replace with a NGCC in 2017. Between 2015 and 2017, rely on the PJM market for any capacity shortfalls.

- "Market" Plan:
    - Same as the "Gas" plan except rely solely on the market to replace Tanners Creek 4 (i.e., do not replace TC4 with a NGCC.)

5. I&M Portfolio Results

Given the range of three fundamental pricing scenarios developed by AEP-Fundamental Analysis, as well as the modeling constraints and certain planning commitments, *Strategist*® modeling was used to develop the CPWs for the Base Plan, Gas Plan and the Market Plan.

Exhibit 8-6 summarizes the plan portfolios. This exhibit shows the new resources required to meet the RTO IRM requirements as well as plan costs over the full (2011-2040) extended planning horizon, and under the various pricing scenarios.

6. I&M Optimal Portfolio Summary

As suggested in Exhibit 8-6**,** the Base Plan has the lowest CPW of the three plans under all pricing scenarios. I&M is seeking regulatory approvals to formally implement the underpinnings of this plan – that is, the environmental equipment retrofit of a single Rockport Unit as well as the retirement on Tanners Creek 1-3 by December 31, 2014.

7. I&M Additional Risk Analysis

The Base, Gas, and Market Plan views as set forth by the discrete I&M capacity resource modeling performed using *Strategist*® were analyzed further utilizing the *Aurora*^{XMP} application's "risk modeling" feature described later in Section D. These I&M-specific resource portfolio options created in *Strategist*® and the comparison of the respective incremental, life-cycle revenue requirements show economic results based on specific, very reasonable, yet discrete "point estimates" of the underlying variables that could affect these economics. Using a Monte Carlo technique, the *Aurora*^{XMP} tool offers an additional approach by which to "test" these plans over a distributed range of certain key variables. This provided a "probability-weighted" solution that offers additional insight surrounding relative cost/price risk.

8. Optimum AEP-East Resource Portfolios for Four Economic/Pricing Scenarios

For AEP-East, modeling was performed by treating the entire AEP-East System as one entity, as it is seen by PJM using the Market Plan and the Build Plan. In these portfolios, the AEP-East fleet meets its internal load requirement, buying or selling capacity and energy into the PJM market to satisfy short or long positions. Outside of this modeling, once a resource addition plan is established, the assignment of resources is based on AEP Pool requirements. The Market and Build portfolios were analyzed under economic/pricing scenarios described in Section B4, with the results shown in Exhibit 8-7.

9. AEP-East Optimal Portfolio Summary

As suggested in Exhibit 8-7, the Market Plan portfolio was slightly better than the Build Plan; however, the differences are relatively small. As such, the Market Plan that was optimized under Fleet Transition-Carbon Adjusted pricing will be used as the Base Plan for AEP-East. This plan allows for flexibility in dealing with the uncertainty around the AEP Pool transition and EGU MACT issues.

D. Risk Assessment (170 IAC 4-7-8(5) and 170 IAC 4-7-8(10)(A,B and C))

Once the discretely-modeled plans listed in Chapter 8C were constructed, they were subjected to "stress testing" to ensure that none of the plans had outcomes that were deleterious under an array of input variables.

1. The *Aurora*XMP Model

The *Aurora*XMP model was developed by EPIS, Inc. in the mid 1990's and has been licensed for use by AEP since 2002. *Aurora*XMP is primarily a production costing model using a fundamentals-based, multi-area, transmission constrained dispatch logic in order to simulate real market conditions. At AEP it is used primarily as a long-term optimization tool to forecast mid- and long-term power prices and other industry commodities for all generating units in the Eastern Interconnect and ERCOT.

One of the features of the *Aurora*XMP model is its endogenous risk analysis capabilities for Monte Carlo simulations. For the purposes of this study, a commonly accepted sampling method (the Latin-Hypercube) was employed in order to generate a plausible distribution of risk factors with a relatively small number of samples or risk iterations.

This study focused solely on the I&M portfolio of generating units. One hundred risk iteration runs were performed with six risk factors being sampled. The results take the form of a distribution of possible revenue requirement outcomes for each plan. The input variables or risk factors considered by *Aurora*XMP within this IRP analysis were:

- coal prices,
- natural gas prices,
- power prices,

- CO_2 emissions allowance prices,
- full requirements loads / demand,
- construction costs / carrying costs

These variables were correlated based on historical data.

Monthly Correlation Targets	Natural Gas	Coal Prices	CO_2 Allowance Prices	Power Prices	Demand
Natural Gas	1	0.09	-0.22	0.87	seasonal
Coal Prices		1	0.69	0.19	0.74
CO_2 Allowance Prices			1	-0.14	0.05
Power Prices				1	0.75
Demand					1

Mean (forecast)	0.003	0.002	0.002	0.005	
St Dev (data	0.123	0.018	0.016	0.204	0.11
St Dev (forecast)		0.2	0.019	0.149	

European Futures

European Futures / US Data validated

US
Data

Hypothesized

2. Modeling Process & Results & Sensitivity Analysis (170 IAC 4-7-8(10)(B))

For each portfolio, the difference between its mean and its 95th percentile was identified as Revenue Requirement at Risk (RRaR). The 95^{th} percentile represents a level of required revenue sufficiently high that it will be exceeded, assuming that the given plan were adopted, with an estimated probability of 5.0 percent. The RRaR represents a measure of risk or uncertainty inherent in each portfolio. The larger the RRaR, the greater the level of risk that customers would be subjected to higher rates.

Figure 8-1 illustrates for the Market Plan, the average levels of some key risk factors, both overall and in the simulated outcomes whose Cumulative Present Value (CPV) revenue requirement is roughly equal to or exceeds the upper bound of Revenue Requirement at Risk. While this figure is specific to the Market Plan, the numbers would be very similar under the other plans. (The particular alternative futures producing the highest levels are not necessarily the same between different plans.) The Construction Costs are shown for a different year than the other risk factors because the Market Plan did not utilize new natural gas production until 2025.

Figure 8-1: Key Risk Factors –Means

	Simulated outcomes - Market Plan				
Risk Factor	**All Outcomes**	**RRaR-Exceeding Outcomes**			**Year**
	Mean	**Mean**	**Difference**	**%Diff**	
Coal prices	2.62	3.01	0.39	14.9%	2020
Natural Gas Prices	7.94	9.40	1.46	18.4%	2025
Power Prices	66.24	69.40	3.16	4.8%	2020
CO2 Emissions Allowance Prices	22.64	28.75	6.12	27.0%	2022
Demand	26,492	32,387	5895	22.3%	2020
FOM, Construction Costs / MW	3.50	3.83	0.33	9.3%	2025

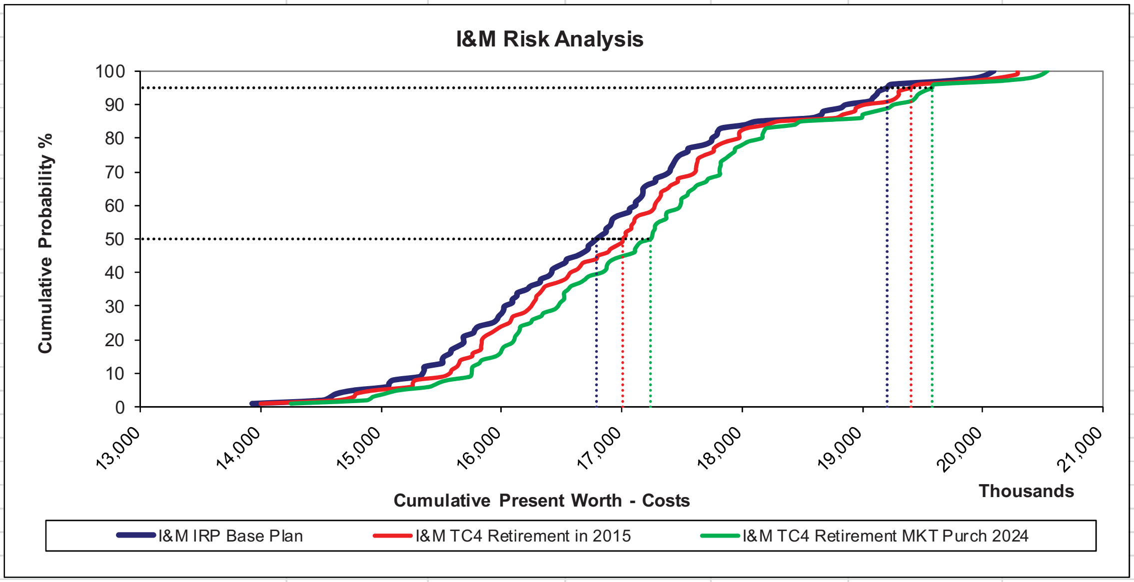
Source: AEP Fundamental Analysis

The price of CO_2 allowances and Demand are greater among the RRaR-exceeding outcomes, suggesting that they are critical sources of risk to revenue requirements. The relative difference between that "tail" and mean outcomes are 27.0% to 22.3% which is somewhat greater than the relative difference of other risk factors.

It might be assumed that the very worst possible futures would be characterized by high fuel and allowance prices and low power prices. But according to the analysis of the historical values of risk factors that underlies this study, such futures have essentially no chance of occurring. Any possible future with high fuel prices would essentially always have high power prices. Likewise the risk factor analysis implies an inverse correlation between CO_2 allowance prices and some of the other risk factors that determine the tail cases, so that in these tail cases, the average CO_2 allowance price is actually less than the average across all possible futures.

Figure 8-2 shows the distribution of outcomes for each of the three plans that were evaluated – the Base Plan, Gas Plan, and Market Plan. Note that these CPV's are consistent with the CPW values calculated using the *Strategist®* tool, with the Base Plan being the lowest cost plan and the Gas and Market plans slightly more expensive. The importance of this evaluation, though, is not in matching the *Strategist®* results, but in examining the relative risk among the portfolios. As the table below Figure 8-2 shows, the difference between the 50th and 95th probability percentile is fairly consistent for each portfolio. This leads to the conclusion that the effects of market risk are similar to the risks associated with construction costs and fuel prices. This reinforces the conclusions from the *Strategist®* optimization analysis – that there is no particular advantage or disadvantage between the Base, Gas and Market portfolios. The table also shows, the difference between the 50th and 95th probability percentile is fairly consistent for each portfolio. This leads us to the conclusion that the effects of market risk are similar to the risks associated with construction costs and fuel prices. This reinforces the conclusions from the *Strategist®* optimization analysis – that there is no particular advantage or disadvantage between the Base, Gas and Market portfolios.

Figure 8-2 – I&M Risk Analysis - Cumulative Present Worth



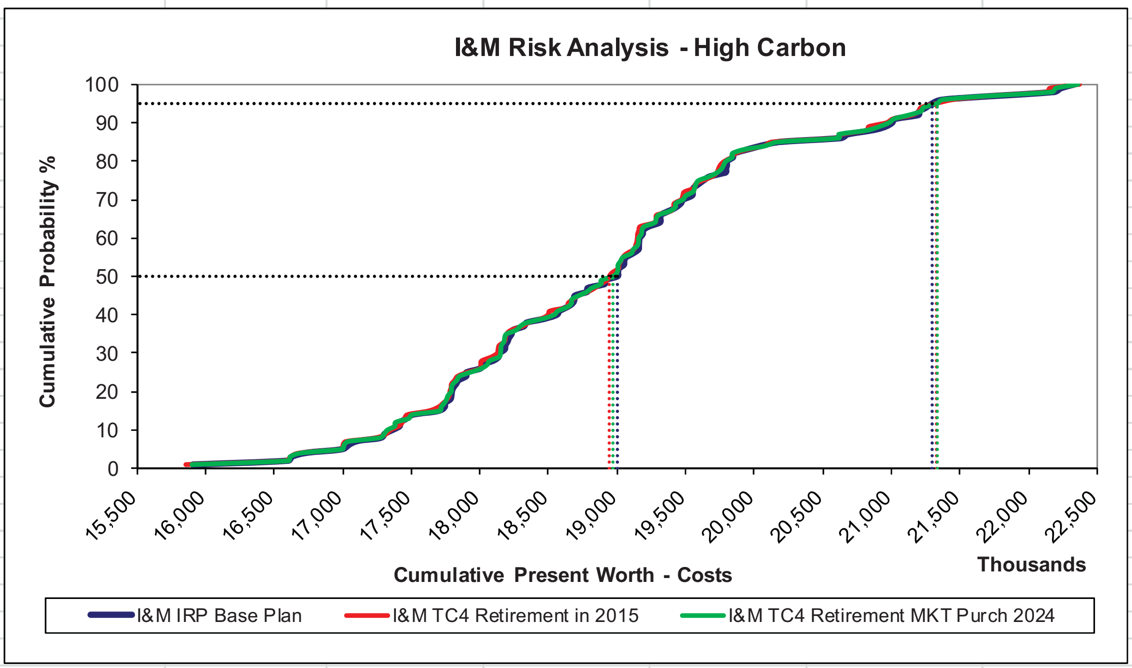
Percentile	I&M IRP Base Plan	I&M TC4 Retirement in 2015	I&M TC4 Retirement MKT Purch 2024	Delta Base - Optimized	Delta Base - Base Plus CES	Delta Optimized - Base Plus CES
50	16,789,247	17,007,095	17,238,026	(217,848)	(448,780)	(230,932)
95	19,205,376	19,404,181	19,579,534	(198,804)	(374,158)	(175,354)
	2,416,130	2,397,086	2,341,508	19,044	74,622	55,578

Source: AEP Fundamental Analysis

An additional sensitivity, related to the cost of GHG/carbon emissions, was also performed. In this sensitivity analysis carbon costs were, in fact, doubled from the base prices assumed in the first set of evaluations performed(*i.e.*, increasing a nominal CO_2 pricing range of \$15-\$30/tonne to as much as \$30-\$60/tonne over the long-term study period). Although the Company believes that such extreme CO_2/carbon pricing range is not plausible due to its attendant impact on regional energy prices, this sensitivity exercise is nonetheless valid to more rigorously "stress" these risk assessments applicable to these alternative planning scenarios. In that regard, however, it is also important to realize that all other variables were assumed to have a similar distribution as the first set of evaluations (*i.e.*, the change in CO_2/carbon pricing was <u>not</u> assumed to have an effect on other variables, such as energy pricing). This was done to somewhat "isolate" the impact of carbon costs on portfolio risk. As can be seen in Figure 8-3, the CPW for all portfolios increases, as expected, however the resulting distribution reduces the difference among the portfolios. The Base portfolio is slightly more expensive than the Gas or Market portfolios at the 50th percentile level, however it is the least expensive portfolio at the 95th percentile level.

The conclusion that can be drawn from this analysis is that under a more restrictive (*i.e.*, higher cost) carbon regime, the three portfolios would become essentially equivalent from a cost/risk perspective. More importantly, it would indicate that the "Base" long-term I&M resource plan being set forth would not be compromised. That is, even under an *extreme* CO_2/carbon view, this Base Plan would continue to be an acceptable alternative from a cost perspective.

Figure 8-3 – I&M Risk Analysis - Cumulative Present Worth



Percentile	I&M IRP Base Plan	I&M TC4 Retirement in 2015	I&M TC4 Retirement MKT Purch 2024	Delta Base - Gas	Delta Base - Mkt	Delta Gas - Mkt
50	19,002,607	18,943,227	18,970,291	59,380	32,316	(27,063)
95	21,296,814	21,328,408	21,334,536	(31,594)	(37,722)	(6,127)
	2,294,207	2,385,181	2,364,245	(90,974)	(70,038)	20,936

E. 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 potential stand-alone entity in the PJM RTO, the Base Plan results in lower costs than the Gas Plan or the Market Plan. Given the uncertainty surrounding the final outcome of both the EGU MACT rulemaking and the AEP Pool termination, the Company is proposing the plan which has the maximum flexibility – the Base Plan. The Base Plan also subjects I&M customers to an acceptable level of risk relative to the Gas and Market plans. The supply-side expansion plan represented in this report is also influenced by I&M's commitment to DSM programs, renewables, and to the need for compliance with environmental regulations. Following are some highlights of the "embedded" features of the plan.

- Potential DSM programs are estimated to reduce the I&M peak demand by 423 MW (summer) and 269 MW (winter) and energy requirements by 1,720 GWh by the end of the forecast period (2031). This is recognized prior to establishing the plan for supply-side resources.
- I&M is already receiving energy from two wind projects with a total nameplate rating of 150 MW. The current plan for I&M reflects no additional wind capacity until 2013.
- In the long-term, 562 MW (summer) of intermediate (NGCC) capacity is projected to be added by 2025.

Assuming I&M is a stand-alone company in PJM beginning in the 2016/17 planning year, I&M may purchase capacity from or sell capacity to the market, or enter into bilateral agreements with either the current AEP-East companies or other generation entities as needed.

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 through 2024 using a combination of existing capacity and demand response measures as shown in Exhibit 8-10.

Exhibit 8-8 also shows the proposed I&M resource plan assuming I&M remains part of the AEP Pool under its current construct. *Note that there is no change in the I&M resource plan between the AEP Pool and No AEP Pool cases.*

F. AEP-East Current Plan (170 IAC 4-7-8(1))

The AEP-East plan is shown in Exhibit 8-9. This plan is based on the Market portfolio analyzed in *Strategist*®. AEP-East will satisfy its reserve margin requirements using a combination of capacity purchases and demand response measures as shown in Exhibit 8-11. Additional renewable resources are included in the AEP-East plan to comply with individual state mandates. Unit retirements and environmental retrofits assume an EGU MACT implementation date of January 1, 2015.

G. 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 significant modifications in the resource plan reflected for both I&M and AEP-East. I&M and AEP are confident that 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, construction cost estimates, and final AEP Pool status. As such changes and assumptions are recognized, updated, and refined, input information will be reevaluated and resource plans modified as appropriate.

H. 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

2011 to 2021 is shown in Exhibit 8-12.

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 2012-2021 period, however, environmental retrofit projects at Rockport and Tanners Creek in addition to life-cycle projects at the Cook Nuclear Plant will require significant investments.

Also, Exhibit 8-12 provides the present value total revenue requirement (G, T, and D) including the utility's resource plan, stated in total dollars, in dollars per kilowatt-hour delivered, with a discount rate specified as required in 170 IAC 4-7-8 (3) for the 2011-2022 period. Information beyond that period is not available.

9) AVOIDED COSTS

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 9-1, 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 PROMOD IV® production cost model.

10) SHORT-TERM ACTION PLAN

10. Short-Term Action Plan (170 IAC 4-7-9)

The I&M Short-Term Action Plan applies to the two-year period November 2011-2013. 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 AEP Pool 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.
- Upon approval of a CPCN, begin engineering and construction activities required to add pollution control equipment to Rockport Plant
- Continue to pursue DSM alternatives
- Continue investigating and evaluating pollution control technologies for Tanners Creek 4.
- Continue with Cook LCM related activities

B. Demand-Side Assessment

I&M's short-term action plan includes continuing the monitoring and evaluation of DSM programs and continuing the 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 4E, 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.

Particular to I&M, in accordance with the Order of the Commission in Cause No. 43959 dated April 27, 2011, I&M continues working as a member of the Program Implementation Oversight Board (OSB) to implement the programs contained in I&M's Three Year DSM Plan which aligns with requirements set forth in Cause 42693, the Phase II Generic Order. The members of the OSB include I&M, OUCC, Indiana Michigan Power Company Industrial Group, Citizens Action Coalition of Indiana, Inc. ("CAC"), and the City of Fort Wayne. I&M's Three Year DSM Plan contains the programs listed in the table below.

I&M THREE YEAR DSM PLAN SAVINGS PROJECTIONS		Energy Savings (MWh) 2011 Projected	2012 Projected	2013 Projected	Program 3 Year Total
Residential Lighting		15,377	21,784	0	46,131
Residential Home Energy Audit		2,166	4,164	6,161	12,668
Residential Low Income Weatherization		1,724	1,724	1,724	5,810
Energy Efficient Schools		1,730	2,141	2,141	6,067
C&I Prescriptive		23,098	44,754	59,191	129,934
Total Core Programs		44,095	74,567	69,217	200,610
Residential Appliance Recycling		4,106	9,580	6,843	21,213
Residential On-Line Audit		3,792	7,293	10,793	21,878
Residential New Construction		296	591	739	1,626
Residential Solar Siting		53	105	158	316
Residential Home Weatherization		751	1,501	2,249	4,501
Residential Home Energy Reporting		18,400	9,200	9,200	36,800
Residential Peak Reduction		72	144	216	432
Renewables & Demonstration		24	24	24	72
C&I Incentives		4,826	12,364	29,674	46,984
C&I Retro-Commissioning Lite		12,921	25,842	34,456	73,219
C&I HVAC Optimization		2,819	8,458	16,916	28,193
C&I Audit		844	1,606	2,636	5,086
C&I New Construction		1,030	1,760	2,434	5,224
Total Core Plus Programs		49,934	78,468	116,338	245,544
TOTAL ENERGY SAVINGS PROJECTION		94,029	153,035	185,555	
I&M PHASE II ORDER YEARLY ENERGY SAVINGS GOAL		77,400	108,400	142,300	

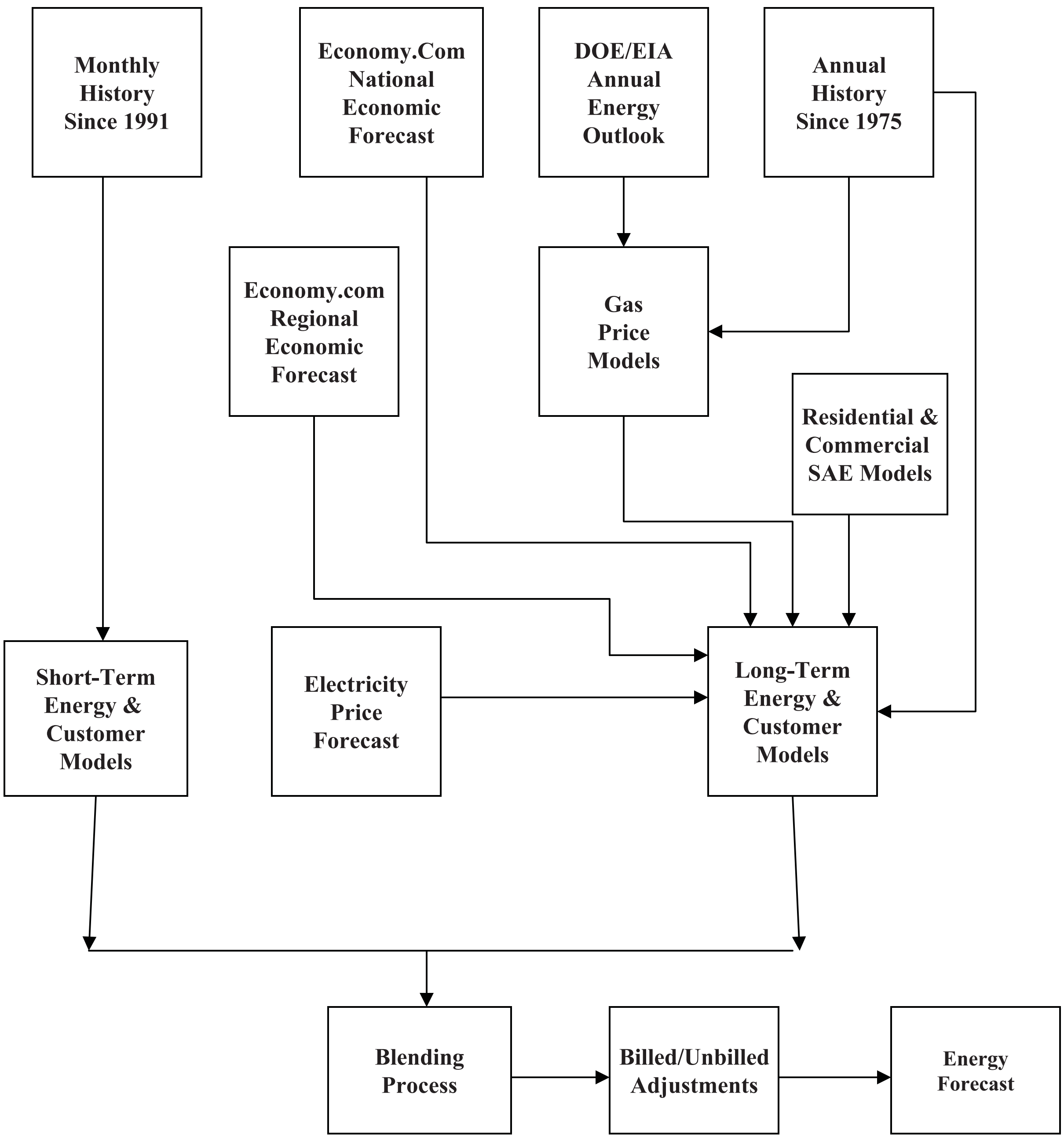
I&M is an active participant in the DSM Coordination Committee (DSMCC) established as directed in Cause 42693. The DSMCC is currently working with the Third Party Administrator (TPA) to establish statewide Core Programs and to transition existing utility administered Core Programs to the statewide model.

The Modified Action Plan (Cause 43959) and Action Plan (Cause 43769), along with other Exhibits presented in Cause 43959, contain detailed descriptions of the programs including all cost-effectiveness tests. The breadth of DSM programs contained within the portfolio of programs approved in Cause 43959 (3 Year DSM Plan) 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.

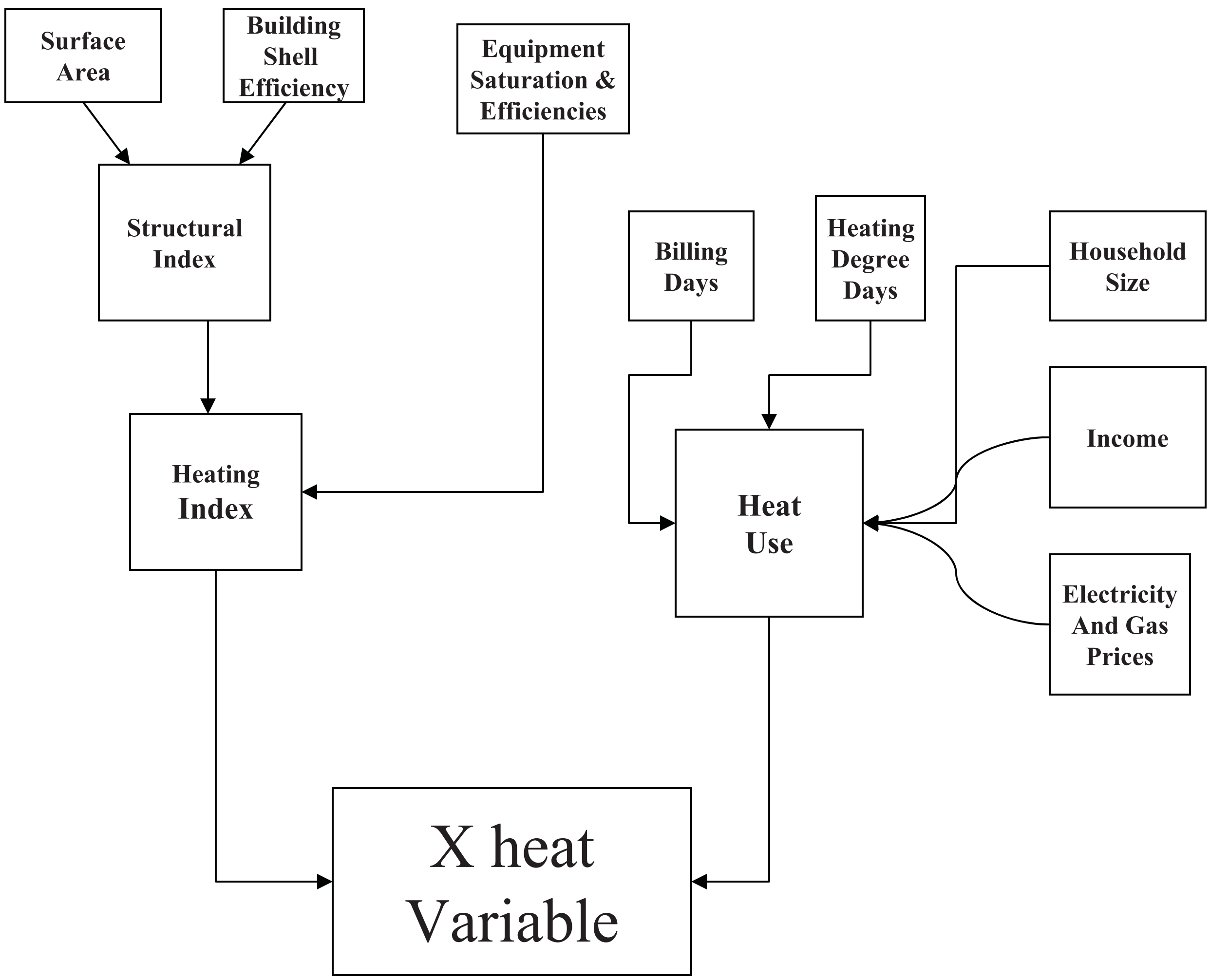
I&M recognizes that there are a variety of methods available to effect demand and energy reductions, including utility-sponsored programs. The judicious deployment of cost-effective demand response tools such as time-of-day, seasonal, and interruptible tariffs to influence the peak use of electricity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

11) EXHIBITS

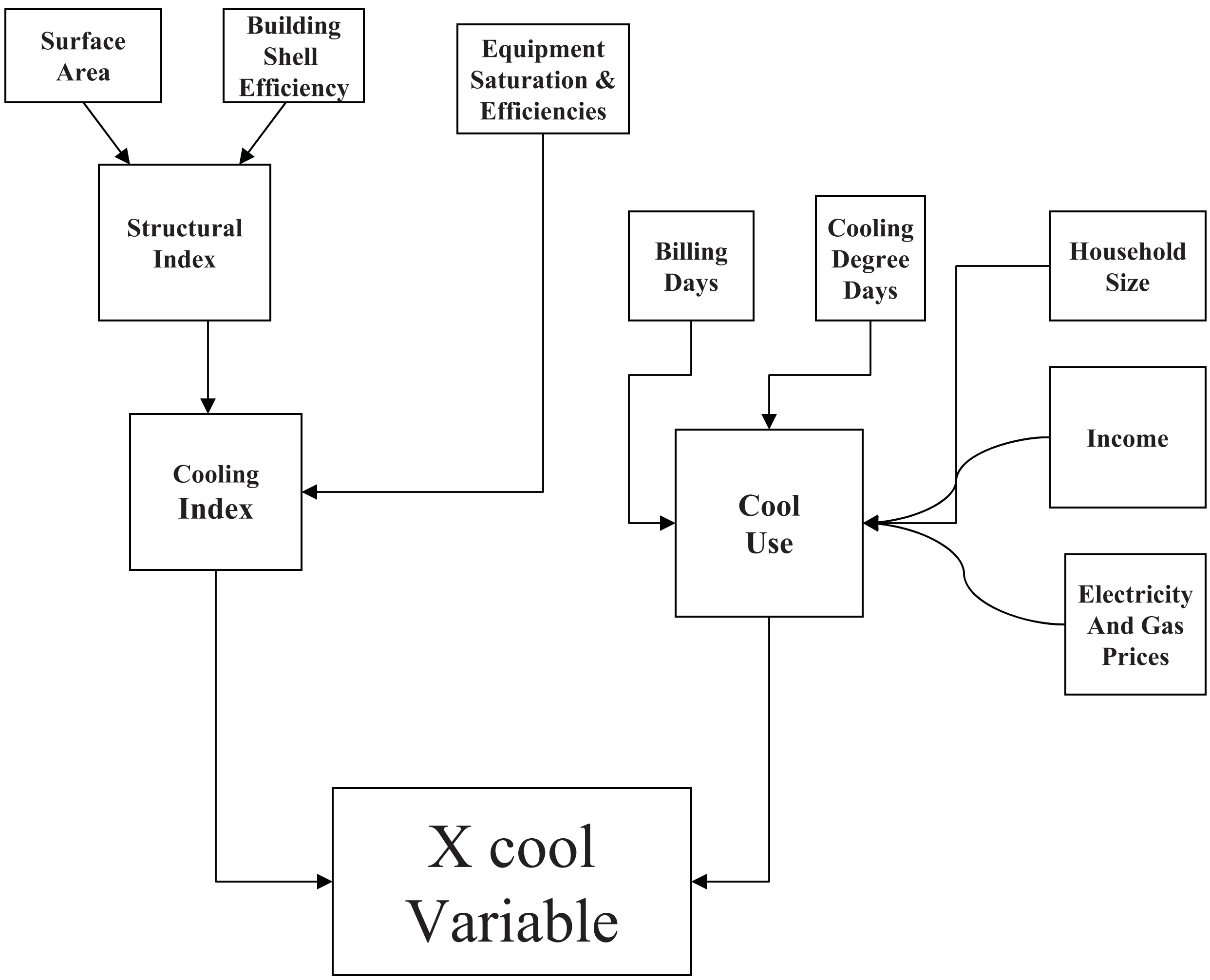
Indiana Michigan Power Company
Internal Energy Requirements Forecasting Method



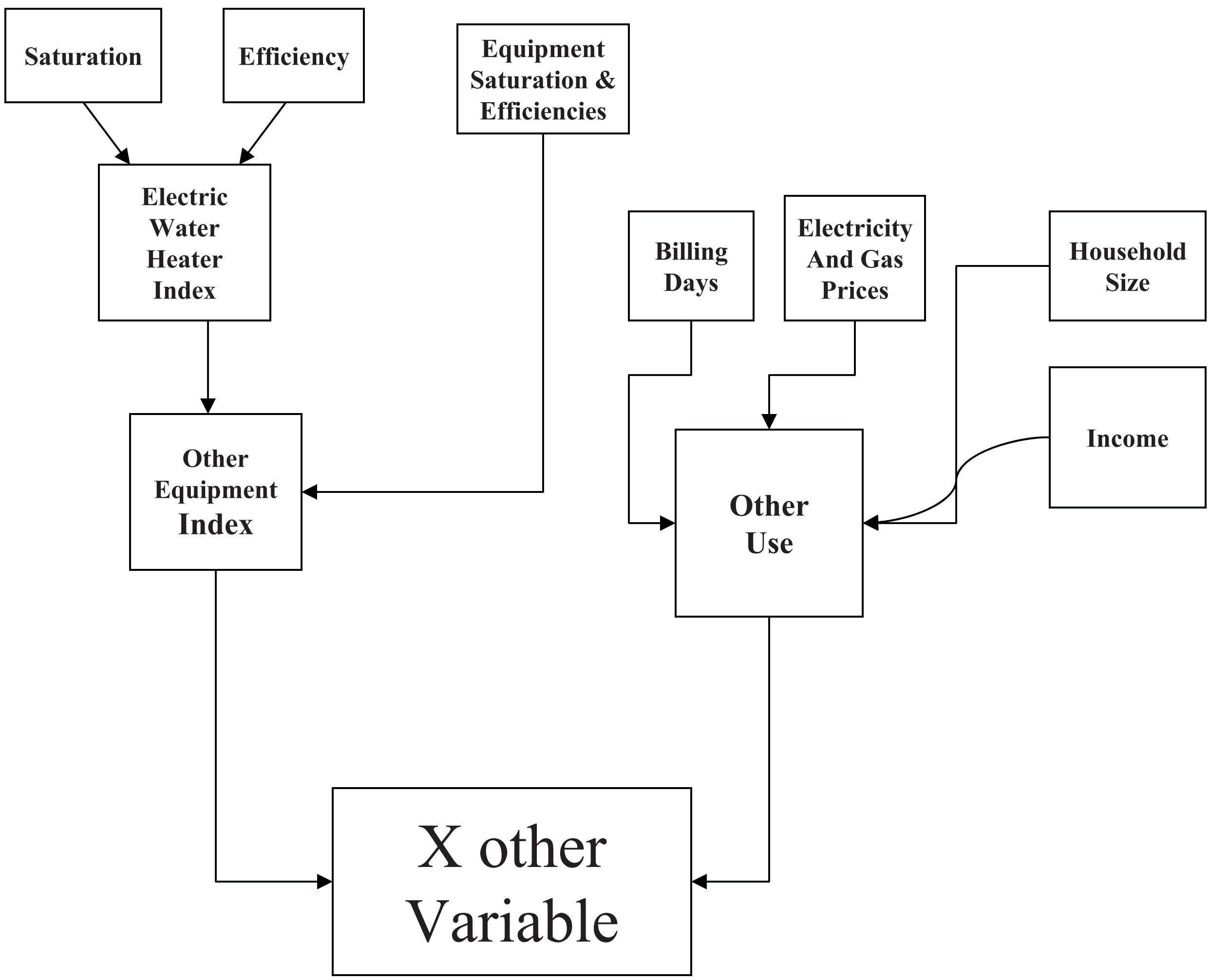
Indiana Michigan Power Company
Residential Statistically Adjusted End-Use Model (SAE)
X heat Variable



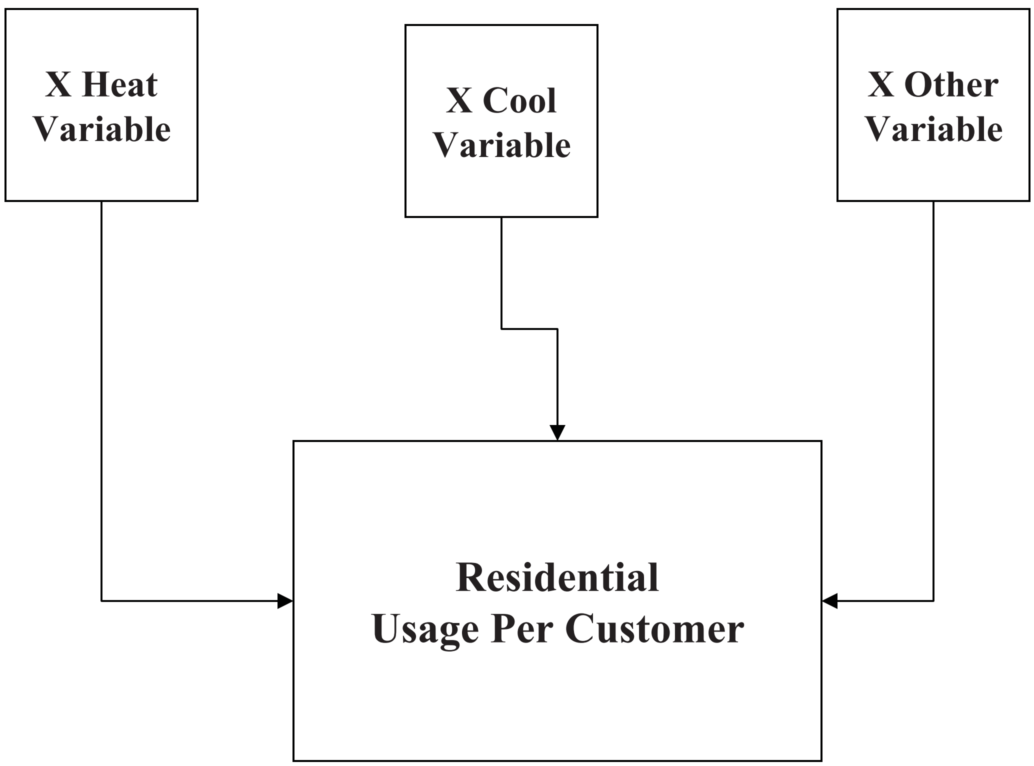
Indiana Michigan Power Company
Residential Statistically Adjusted End-Use Model (SAE)
X cool Variable



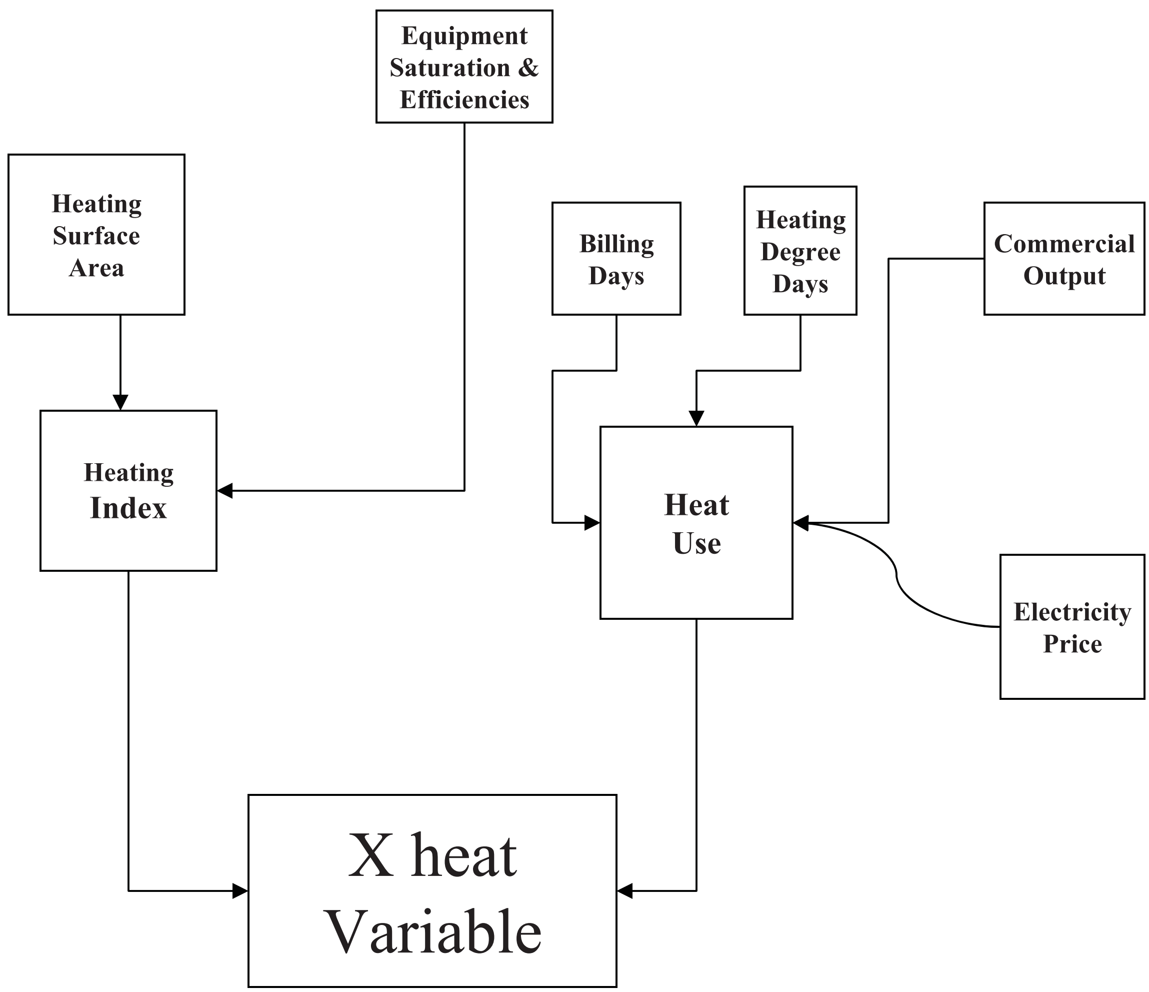
Indiana Michigan Power Company
Residential Statistically Adjusted End-Use Model (SAE)
X other Variable



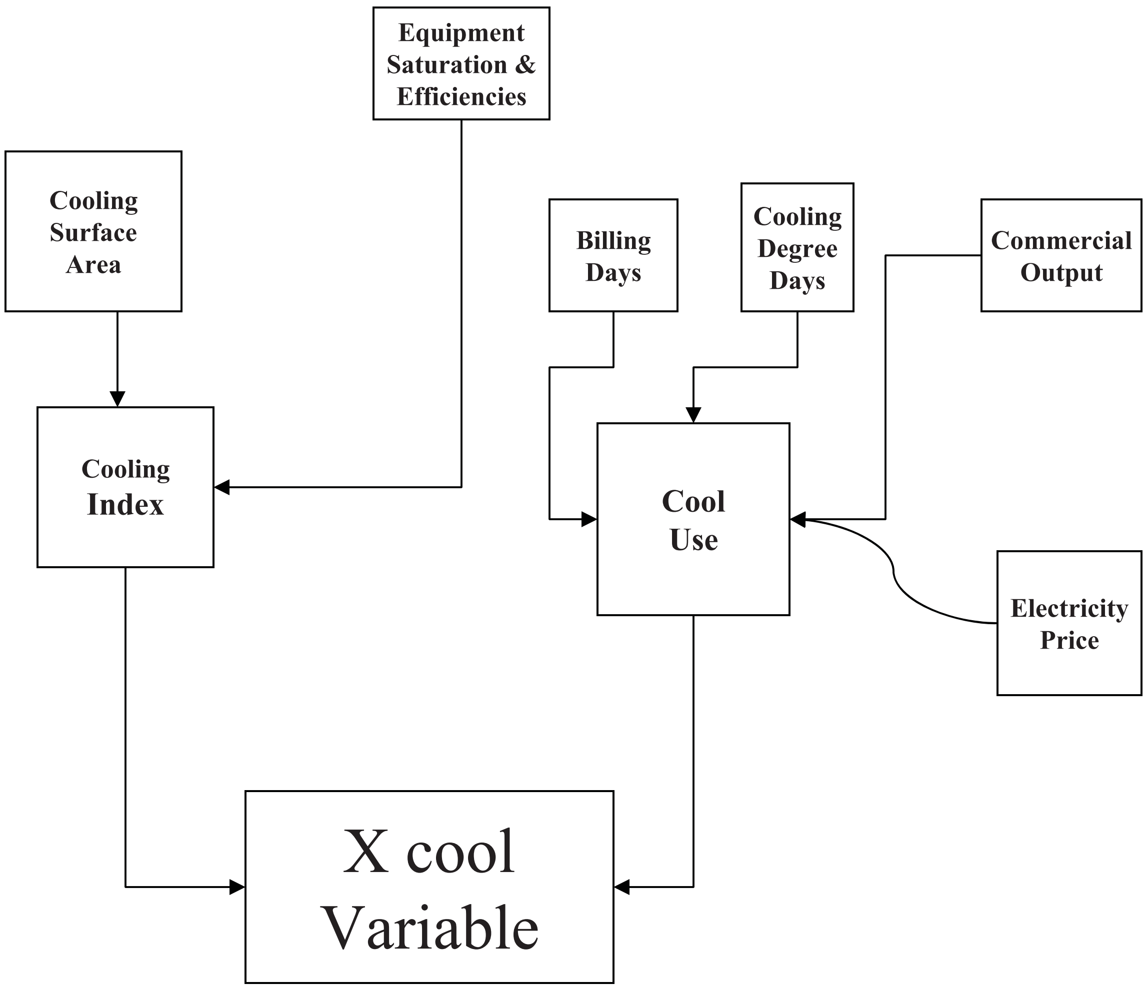
Indiana Michigan Power Company
Residential Statistically Adjusted End-Use Model (SAE)



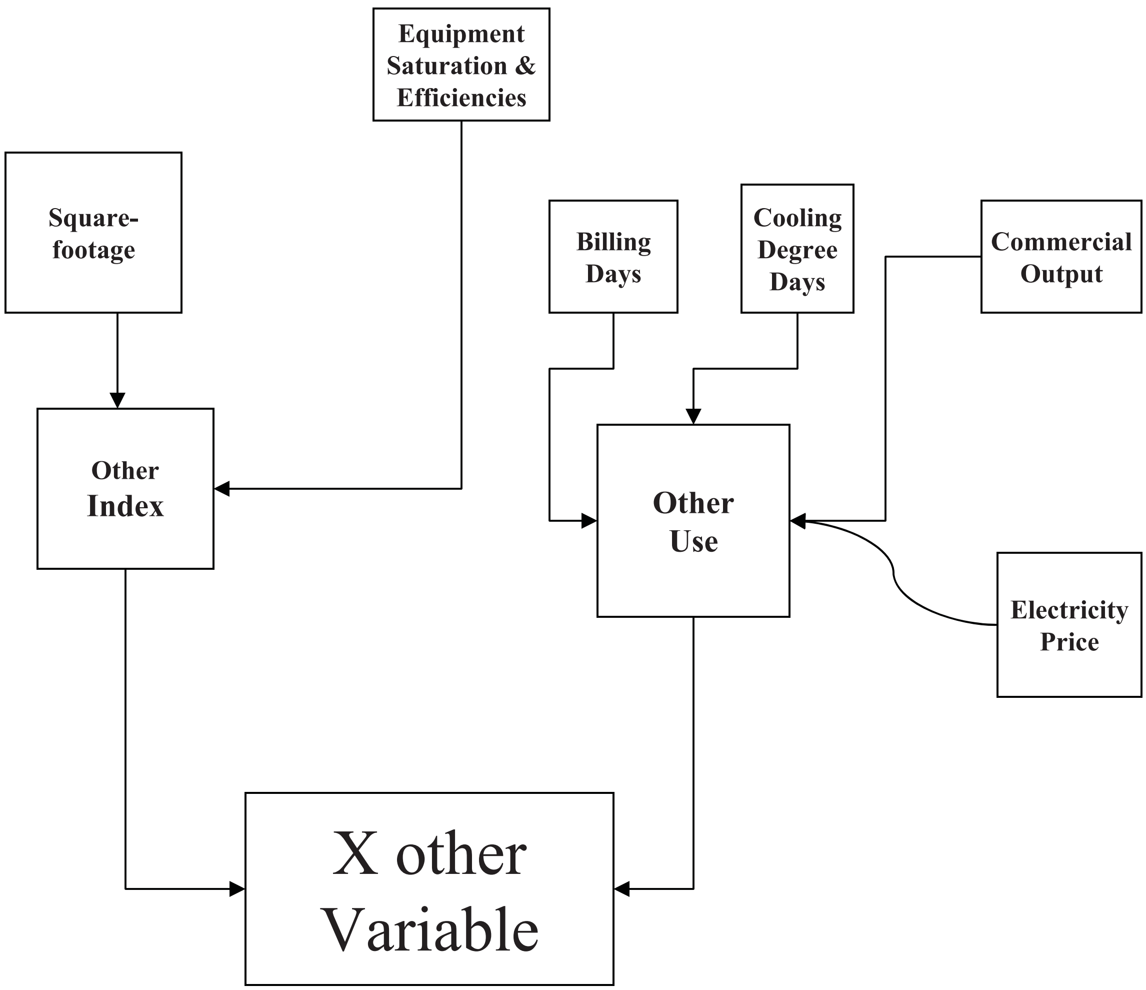
Indiana Michigan Power Company
Commercial Statistically Adjusted End-Use Model (SAE)
X heat Variable



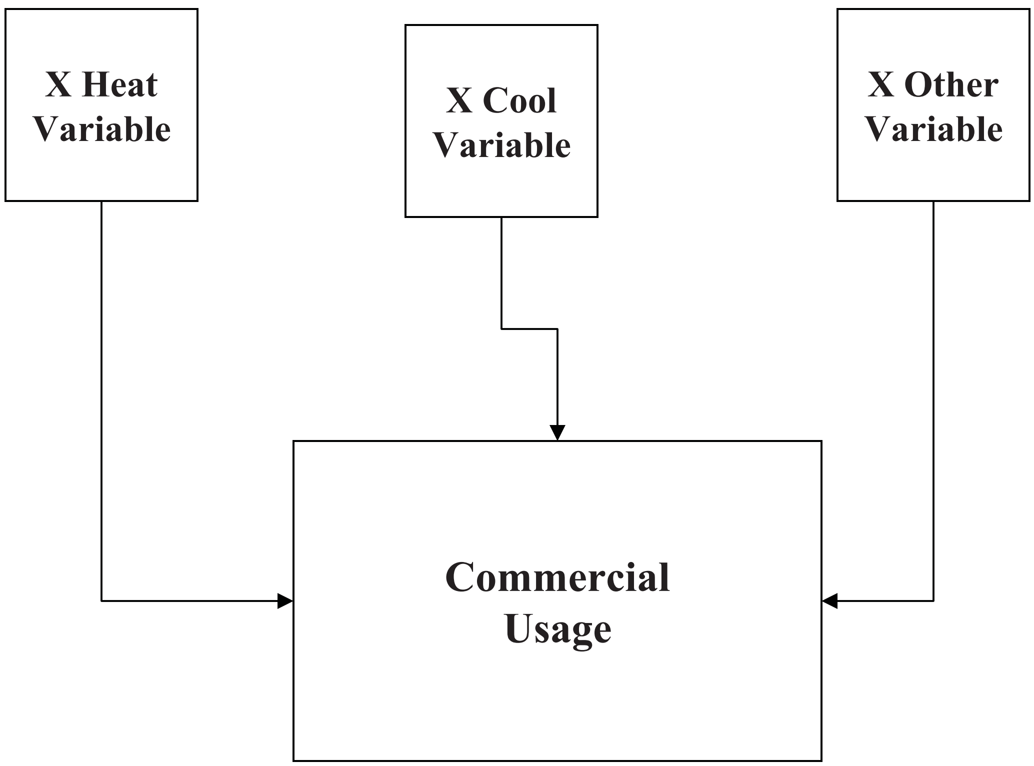
Indiana Michigan Power Company
Commercial Statistically Adjusted End-Use Model (SAE)
X cool Variable



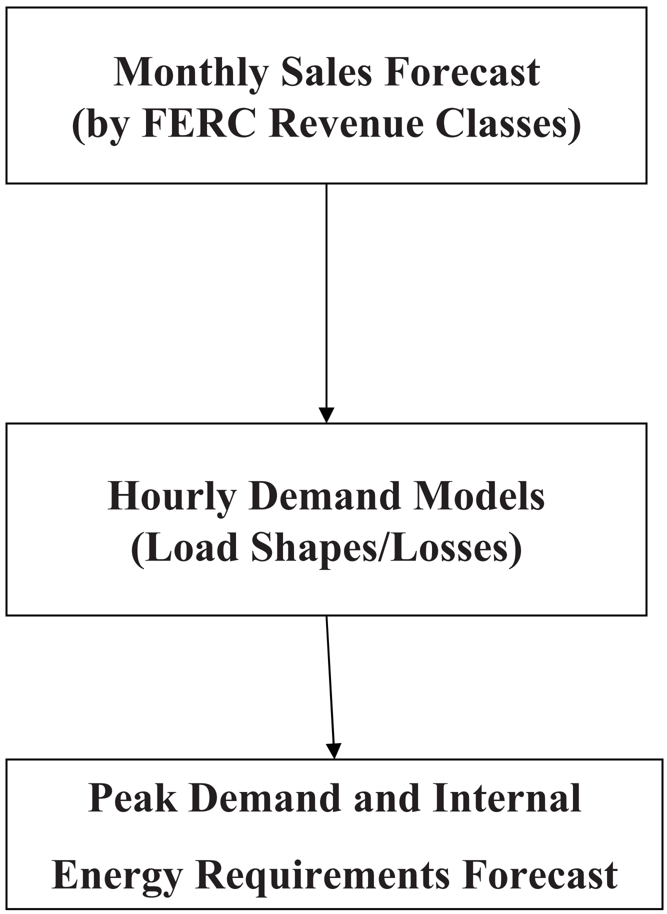
Indiana Michigan Power Company
Commercial Statistically Adjusted End-Use Model (SAE)
X other Variable



Indiana Michigan Power Company
Commercial Statistically Adjusted End-Use Model (SAE)



Indiana Michigan Power Company Peak Demand and Internal Energy Requirements Forecast Process – Sequential Steps



Indiana Michigan Power Company
Annual Internal Energy Requirements and Growth Rates
2001-2031

	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												
2001	5,413	---	4,773	---	7,914	---	2,321	---	1,863	---	22,284	---
2002	5,778	6.7	4,896	2.6	8,198	3.6	2,454	5.7	1,967	5.6	23,293	4.5
2003	5,476	-5.2	4,777	-2.4	7,878	-3.9	2,542	3.6	2,202	11.9	22,876	-1.8
2004	5,524	0.9	4,894	2.4	8,109	2.9	2,757	8.4	1,678	-23.8	22,962	0.4
2005	5,986	8.4	5,090	4.0	8,090	-0.2	2,253	-18.3	1,990	18.6	23,407	1.9
2006	5,784	-3.4	5,068	-0.4	8,049	-0.5	3,580	58.9	1,939	-2.6	24,419	4.3
2007	6,132	6.0	5,373	6.0	7,967	-1.0	4,620	29.1	1,921	-0.9	26,013	6.5
2008	6,059	-1.2	5,272	-1.9	7,536	-5.4	4,629	0.2	1,953	1.7	25,448	-2.2
2009	5,767	-4.8	5,038	-4.4	6,762	-10.3	4,628	0.0	2,101	7.5	24,296	-4.5
2010	6,083	5.5	5,121	1.6	7,445	10.1	4,887	5.6	2,293	9.1	25,828	6.3
2011*	5,925	-2.6	5,133	0.2	7,513	0.9	4,954	1.4	1,986	-13.4	25,512	-1.2
Forecast												
2012	5,890	-0.6	5,243	2.1	7,826	4.2	5,065	2.2	2,145	8.0	26,169	2.6
2013	5,894	0.1	5,304	1.2	8,098	3.5	5,210	2.9	2,115	-1.4	26,621	1.7
2014	5,850	-0.7	5,267	-0.7	7,967	-1.6	5,276	1.3	2,140	1.2	26,500	-0.5
2015	5,796	-0.9	5,237	-0.6	7,824	-1.8	5,359	1.6	2,150	0.5	26,366	-0.5
2016	5,749	-0.8	5,208	-0.5	7,732	-1.2	5,411	1.0	2,143	-0.3	26,244	-0.5
2017	5,707	-0.7	5,187	-0.4	7,657	-1.0	5,491	1.5	2,116	-1.3	26,158	-0.3
2018	5,659	-0.8	5,161	-0.5	7,575	-1.1	5,542	0.9	2,103	-0.6	26,039	-0.5
2019	5,614	-0.8	5,142	-0.4	7,476	-1.3	5,620	1.4	2,104	0.1	25,956	-0.3
2020	5,598	-0.3	5,141	0.0	7,407	-0.9	5,665	0.8	2,096	-0.4	25,907	-0.2
2021	5,613	0.3	5,167	0.5	7,383	-0.3	5,739	1.3	2,077	-0.9	25,978	0.3
2022	5,617	0.1	5,178	0.2	7,360	-0.3	5,787	0.8	2,102	1.2	26,044	0.3
2023	5,633	0.3	5,202	0.5	7,389	0.4	5,814	0.5	2,115	0.6	26,152	0.4
2024	5,660	0.5	5,239	0.7	7,443	0.7	5,842	0.5	2,125	0.4	26,308	0.6
2025	5,695	0.6	5,293	1.0	7,510	0.9	5,872	0.5	2,113	-0.5	26,484	0.7
2026	5,718	0.4	5,334	0.8	7,566	0.7	5,899	0.5	2,142	1.4	26,659	0.7
2027	5,749	0.5	5,381	0.9	7,627	0.8	5,928	0.5	2,150	0.4	26,834	0.7
2028	5,768	0.3	5,415	0.6	7,683	0.7	5,958	0.5	2,199	2.3	27,023	0.7
2029	5,815	0.8	5,481	1.2	7,765	1.1	5,991	0.6	2,163	-1.6	27,215	0.7
2030	5,836	0.4	5,521	0.7	7,831	0.9	6,026	0.6	2,202	1.8	27,416	0.7
2031	5,874	0.6	5,568	0.8	7,904	0.9	6,058	0.5	2,219	0.7	27,622	0.8

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

Average Annual Growth Rates												
2001-2011		0.9		0.7		-0.5		7.9		0.6		1.4
2012-2031		0.0		0.3		0.1		0.9		0.2		0.3

Indiana Michigan Power Company-Indiana
Annual Internal Energy Requirements and Growth Rates
2001-2031

	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												
2001	4,281	---	4,050	---	6,874	---	1,982	---	1,566	---	18,752	---
2002	4,581	7.0	4,144	2.3	7,118	3.5	2,100	6.0	1,654	5.6	19,597	4.5
2003	4,329	-5.5	4,044	-2.4	6,825	-4.1	2,194	4.5	1,852	12.0	19,243	-1.8
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*	4,668	-2.9	4,326	0.5	6,667	1.1	4,334	1.7	1,663	-14.5	21,659	-1.2
Forecast												
2012	4,635	-0.7	4,428	2.4	6,937	4.0	4,441	2.5	1,786	7.4	22,228	2.6
2013	4,643	0.2	4,478	1.1	7,224	4.1	4,580	3.1	1,766	-1.2	22,691	2.1
2014	4,612	-0.7	4,448	-0.7	7,119	-1.5	4,640	1.3	1,791	1.5	22,610	-0.4
2015	4,561	-1.1	4,415	-0.7	6,985	-1.9	4,718	1.7	1,800	0.5	22,479	-0.6
2016	4,513	-1.0	4,382	-0.8	6,888	-1.4	4,764	1.0	1,791	-0.5	22,338	-0.6
2017	4,467	-1.0	4,352	-0.7	6,800	-1.3	4,837	1.5	1,764	-1.5	22,221	-0.5
2018	4,417	-1.1	4,319	-0.8	6,710	-1.3	4,883	0.9	1,749	-0.9	22,078	-0.6
2019	4,370	-1.1	4,294	-0.6	6,612	-1.5	4,959	1.6	1,747	-0.1	21,982	-0.4
2020	4,353	-0.4	4,289	-0.1	6,550	-0.9	5,005	0.9	1,738	-0.5	21,935	-0.2
2021	4,364	0.3	4,311	0.5	6,532	-0.3	5,079	1.5	1,723	-0.9	22,009	0.3
2022	4,365	0.0	4,319	0.2	6,511	-0.3	5,125	0.9	1,744	1.2	22,064	0.3
2023	4,376	0.3	4,337	0.4	6,532	0.3	5,147	0.4	1,754	0.6	22,146	0.4
2024	4,396	0.4	4,366	0.7	6,574	0.6	5,171	0.5	1,761	0.4	22,269	0.6
2025	4,421	0.6	4,411	1.0	6,628	0.8	5,197	0.5	1,750	-0.6	22,407	0.6
2026	4,437	0.4	4,443	0.7	6,669	0.6	5,221	0.5	1,774	1.3	22,544	0.6
2027	4,460	0.5	4,482	0.9	6,714	0.7	5,244	0.4	1,779	0.3	22,679	0.6
2028	4,474	0.3	4,509	0.6	6,754	0.6	5,269	0.5	1,819	2.2	22,825	0.6
2029	4,510	0.8	4,563	1.2	6,817	0.9	5,295	0.5	1,788	-1.7	22,973	0.6
2030	4,526	0.3	4,595	0.7	6,864	0.7	5,323	0.5	1,819	1.8	23,126	0.7
2031	4,554	0.6	4,631	0.8	6,914	0.7	5,348	0.5	1,831	0.7	23,279	0.7

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

Average Annual Growth Rates	Residential	Commercial	Industrial	Other Internal	Losses	Total
2001-2011	0.9	0.7	-0.3	8.1	0.6	1.5
2012-2031	-0.1	0.2	0.0	1.0	0.1	0.2

Indiana Michigan Power Company-Michigan
Annual Internal Energy Requirements and Growth Rates
2001-2031

	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												
2001	1,133	---	723	---	1,040	---	339	---	297	---	3,532	---
2002	1,197	5.7	751	3.9	1,080	3.8	354	4.3	314	5.5	3,695	4.6
2003	1,147	-4.1	733	-2.4	1,054	-2.4	348	-1.6	350	11.5	3,633	-1.7
2004	1,146	-0.2	743	1.2	1,074	1.9	354	1.7	261	-25.2	3,578	-1.5
2005	1,247	8.9	784	5.5	1,071	-0.2	370	4.5	322	23.4	3,795	6.1
2006	1,204	-3.5	766	-2.3	1,025	-4.3	585	58.1	297	-7.9	3,877	2.2
2007	1,261	4.7	835	9.0	1,009	-1.6	610	4.3	296	-0.5	4,010	3.4
2008	1,262	0.1	839	0.5	923	-8.5	590	-3.3	300	1.3	3,914	-2.4
2009	1,218	-3.5	804	-4.1	785	-15.0	576	-2.4	319	6.5	3,702	-5.4
2010	1,277	4.8	816	1.4	852	8.5	626	8.6	347	8.7	3,917	5.8
2011*	1,257	-1.5	807	-1.0	846	-0.6	619	-1.0	323	-7.0	3,853	-1.6
Forecast												
2012	1,255	-0.2	815	0.9	889	5.1	624	0.8	359	11.1	3,941	2.3
2013	1,252	-0.3	826	1.4	873	-1.8	630	1.0	349	-2.7	3,930	-0.3
2014	1,238	-1.1	820	-0.8	848	-2.9	636	0.8	348	-0.1	3,890	-1.0
2015	1,236	-0.2	822	0.2	839	-1.0	641	0.8	350	0.5	3,887	-0.1
2016	1,236	0.0	826	0.6	844	0.6	647	1.0	352	0.5	3,906	0.5
2017	1,240	0.3	835	1.0	857	1.5	654	1.1	352	-0.1	3,936	0.8
2018	1,242	0.2	842	0.9	865	0.9	659	0.7	354	0.6	3,961	0.6
2019	1,244	0.1	848	0.7	865	0.0	661	0.3	357	0.9	3,974	0.3
2020	1,246	0.1	852	0.5	857	-0.9	660	-0.1	358	0.1	3,972	0.0
2021	1,249	0.3	856	0.5	851	-0.7	659	-0.1	354	-0.9	3,970	-0.1
2022	1,252	0.2	859	0.4	849	-0.2	662	0.4	358	1.1	3,980	0.3
2023	1,257	0.4	865	0.7	857	0.9	667	0.7	361	0.8	4,006	0.7
2024	1,264	0.6	872	0.9	869	1.4	671	0.6	364	0.7	4,040	0.8
2025	1,274	0.8	882	1.1	883	1.6	675	0.6	363	-0.3	4,077	0.9
2026	1,281	0.5	890	0.9	897	1.6	679	0.6	368	1.6	4,115	0.9
2027	1,289	0.6	899	1.0	913	1.8	684	0.7	371	0.6	4,155	1.0
2028	1,293	0.4	906	0.8	928	1.7	690	0.8	380	2.5	4,198	1.0
2029	1,305	0.9	918	1.3	948	2.1	696	0.9	375	-1.2	4,242	1.1
2030	1,311	0.4	926	0.9	967	2.0	703	1.0	383	2.1	4,290	1.1
2031	1,320	0.7	936	1.1	990	2.3	710	1.0	388	1.1	4,343	1.2

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

Average Annual Growth Rates	Residential % Growth	Commercial % Growth	Industrial % Growth	Other Internal % Growth	Losses % Growth	Total % Growth
2001-2011	1.0	1.1	-2.0	6.2	0.8	0.9
2012-2031	0.3	0.7	0.6	0.7	0.4	0.5

Indiana Michigan Power Company
Composition of Forecast of Other Internal Sales (GWh)
2012-2031

	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
2012	62	1,221	1,434	1,723	4,441	11	613	0	624	74	2,047	1,221	1,723	5,065
2013	62	1,248	1,459	1,811	4,580	11	619	0	630	73	2,078	1,248	1,811	5,210
2014	62	1,261	1,477	1,840	4,640	11	625	0	636	73	2,102	1,261	1,840	5,276
2015	61	1,273	1,486	1,898	4,718	11	630	0	641	72	2,116	1,273	1,898	5,359
2016	60	1,284	1,493	1,927	4,764	11	636	0	647	71	2,129	1,284	1,927	5,411
2017	60	1,294	1,498	1,986	4,837	11	643	0	654	70	2,141	1,294	1,986	5,491
2018	59	1,304	1,505	2,015	4,883	11	648	0	659	70	2,153	1,304	2,015	5,542
2019	58	1,315	1,513	2,074	4,959	11	650	0	661	69	2,163	1,315	2,074	5,620
2020	58	1,325	1,519	2,102	5,005	11	649	0	660	68	2,169	1,325	2,102	5,665
2021	58	1,337	1,524	2,161	5,079	11	649	0	659	68	2,172	1,337	2,161	5,739
2022	58	1,349	1,529	2,190	5,125	11	651	0	662	68	2,180	1,349	2,190	5,787
2023	58	1,359	1,540	2,190	5,147	11	656	0	667	68	2,196	1,359	2,190	5,814
2024	58	1,370	1,554	2,190	5,171	11	660	0	671	68	2,214	1,370	2,190	5,842
2025	58	1,381	1,569	2,190	5,197	11	664	0	675	68	2,233	1,381	2,190	5,872
2026	58	1,391	1,582	2,190	5,221	11	668	0	679	68	2,250	1,391	2,190	5,899
2027	58	1,402	1,595	2,190	5,244	11	673	0	684	68	2,268	1,402	2,190	5,928
2028	58	1,413	1,608	2,190	5,269	11	679	0	690	68	2,287	1,413	2,190	5,958
2029	58	1,425	1,623	2,190	5,295	11	685	0	696	69	2,308	1,425	2,190	5,991
2030	58	1,438	1,637	2,190	5,323	11	692	0	703	69	2,329	1,438	2,190	6,026
2031	58	1,450	1,650	2,190	5,348	11	699	0	710	69	2,350	1,450	2,190	6,058

AEP System - East Zone
Annual Internal Energy Requirements and Growth Rates
2001-2031

	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												
2001	32,765	---	25,656	---	40,588	---	4,957	---	8,516	---	112,482	---
2002	35,045	7.0	26,564	3.5	40,734	0.4	5,054	1.9	9,055	6.3	116,452	3.5
2003	34,352	-2.0	26,568	0.0	39,513	-3.0	5,099	0.9	9,257	2.2	114,791	-1.4
2004	34,921	1.7	26,966	1.5	40,986	3.7	4,642	-9.0	9,417	1.7	116,932	1.9
2005	37,067	6.1	28,201	4.6	41,967	2.4	3,696	-20.4	10,144	7.7	121,075	3.5
2006	35,662	-3.8	28,056	-0.5	42,663	1.7	5,449	47.4	10,331	1.8	122,161	0.9
2007	30,283	-15.1	29,649	5.7	46,358	8.7	6,951	27.6	10,144	-1.8	123,386	1.0
2008	37,321	23.2	29,194	-1.5	47,278	2.0	7,472	7.5	10,329	1.8	131,594	6.7
2009	36,186	-3.0	28,490	-2.4	39,243	-17.0	7,455	-0.2	9,628	-6.8	121,002	-8.0
2010	38,446	6.2	29,113	2.2	41,344	5.4	7,304	-2.0	9,917	3.0	126,125	4.2
2011*	37,016	-3.7	28,636	-1.6	42,903	3.8	7,312	0.1	10,007	0.9	125,874	-0.2
Forecast												
2012	36,723	-0.8	28,889	0.9	44,475	3.7	7,444	1.8	9,585	-4.2	127,117	1.0
2013	36,721	0.0	29,147	0.9	45,147	1.5	7,606	2.2	9,539	-0.5	128,161	0.8
2014	36,659	-0.2	29,183	0.1	44,951	-0.4	7,699	1.2	9,563	0.3	128,055	-0.1
2015	36,580	-0.2	29,253	0.2	44,667	-0.6	7,808	1.4	9,581	0.2	127,890	-0.1
2016	36,477	-0.3	29,354	0.3	44,554	-0.3	7,881	0.9	9,619	0.4	127,885	0.0
2017	36,403	-0.2	29,474	0.4	44,515	-0.1	7,982	1.3	9,548	-0.7	127,921	0.0
2018	36,367	-0.1	29,624	0.5	44,522	0.0	8,057	0.9	9,537	-0.1	128,107	0.1
2019	36,303	-0.2	29,742	0.4	44,482	-0.1	8,162	1.3	9,571	0.4	128,260	0.1
2020	36,261	-0.1	29,842	0.3	44,502	0.0	8,236	0.9	9,608	0.4	128,449	0.1
2021	36,377	0.3	30,069	0.8	44,679	0.4	8,340	1.3	9,538	-0.7	129,004	0.4
2022	36,486	0.3	30,242	0.6	44,767	0.2	8,415	0.9	9,654	1.2	129,564	0.4
2023	36,667	0.5	30,415	0.6	44,887	0.3	8,466	0.6	9,704	0.5	130,139	0.4
2024	36,908	0.7	30,580	0.5	45,007	0.3	8,520	0.6	9,759	0.6	130,774	0.5
2025	37,186	0.8	30,828	0.8	45,181	0.4	8,575	0.6	9,704	-0.6	131,473	0.5
2026	37,458	0.7	31,064	0.8	45,317	0.3	8,627	0.6	9,830	1.3	132,298	0.6
2027	37,781	0.9	31,342	0.9	45,583	0.6	8,682	0.6	9,887	0.6	133,275	0.7
2028	38,060	0.7	31,576	0.7	45,846	0.6	8,739	0.7	10,118	2.3	134,339	0.8
2029	38,436	1.0	31,904	1.0	46,180	0.7	8,801	0.7	9,993	-1.2	135,313	0.7
2030	38,724	0.7	32,142	0.7	46,514	0.7	8,863	0.7	10,132	1.4	136,375	0.8
2031	39,090	0.9	32,430	0.9	46,850	0.7	8,924	0.7	10,200	0.7	137,494	0.8

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

Average Annual Growth Rates

	Residential	Commercial	Industrial	Other Internal	Losses	Total
2001-2011	1.2	1.1	0.6	4.0	1.6	1.1
2012-2031	0.3	0.6	0.3	1.0	0.3	0.4

Indiana Michigan Power Company

Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor

2001-2031

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2001	08/08/01	4,232	---	12/31/00	3,393	---	4,232	---	22,284	---	60.1
2002	07/22/02	4,303	1.7	03/04/02	3,258	-4.0	4,303	1.7	23,293	4.5	61.8
2003	08/21/03	4,223	-1.9	01/07/03	3,683	13.0	4,223	-1.9	22,876	-1.8	61.8
2004	07/22/04	4,016	-4.9	01/22/04	3,465	-5.9	4,016	-4.9	22,962	0.4	65.1
2005	08/09/05	4,193	4.4	01/28/05	3,465	0.0	4,193	4.4	23,407	1.9	63.7
2006	07/31/06	4,650	10.9	12/08/05	3,537	2.1	4,650	10.9	24,419	4.3	59.9
2007	08/07/07	4,528	-2.6	02/06/07	3,945	11.5	4,528	-2.6	26,013	6.5	65.6
2008	07/31/08	4,264	-5.8	01/25/08	3,875	-1.8	4,264	-5.8	25,448	-2.2	67.9
2009	06/25/09	4,262	0.0	01/15/09	3,728	-3.8	4,262	0.0	24,296	-4.5	65.1
2010	07/23/10	4,474	5.0	12/10/09	3,858	3.5	4,474	5.0	25,828	6.3	65.9
2011*	07/21/11	4,837	8.1	12/13/10	3,785	-1.9	4,837	8.1	25,512	-1.2	60.0
Forecast											
2012		4,527	-6.4		3,932	3.9	4,527	-6.4	26,169	2.6	66.0
2013		4,613	1.9		4,007	1.9	4,613	1.9	26,621	1.7	65.9
2014		4,597	-0.4		3,988	-0.5	4,597	-0.4	26,500	-0.5	65.8
2015		4,579	-0.4		3,963	-0.6	4,579	-0.4	26,366	-0.5	65.7
2016		4,558	-0.5		3,930	-0.8	4,558	-0.5	26,244	-0.5	65.7
2017		4,560	0.0		3,915	-0.4	4,560	0.0	26,158	-0.3	65.5
2018		4,550	-0.2		3,894	-0.5	4,550	-0.2	26,039	-0.5	65.3
2019		4,545	-0.1		3,878	-0.4	4,545	-0.1	25,956	-0.3	65.2
2020		4,536	-0.2		3,856	-0.6	4,536	-0.2	25,907	-0.2	65.2
2021		4,563	0.6		3,874	0.5	4,563	0.6	25,978	0.3	65.0
2022		4,580	0.4		3,882	0.2	4,580	0.4	26,044	0.3	64.9
2023		4,605	0.5		3,888	0.2	4,605	0.5	26,152	0.4	64.8
2024		4,628	0.5		3,898	0.3	4,628	0.5	26,308	0.6	64.9
2025		4,676	1.0		3,935	0.9	4,676	1.0	26,484	0.7	64.7
2026		4,713	0.8		3,959	0.6	4,713	0.8	26,659	0.7	64.6
2027		4,750	0.8		3,983	0.6	4,750	0.8	26,834	0.7	64.5
2028		4,780	0.6		4,000	0.4	4,780	0.6	27,023	0.7	64.5
2029		4,828	1.0		4,029	0.7	4,828	1.0	27,215	0.7	64.4
2030		4,870	0.9		4,057	0.7	4,870	0.9	27,416	0.7	64.3
2031		4,912	0.9		4,088	0.8	4,912	0.9	27,622	0.8	64.2

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

AEP System - East Zone

Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor

2001-2031

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2001	08/08/01	20,218	---	01/03/01	18,634	---	20,218	---	112,482	---	63.5
2002	08/01/02	20,402	0.9	02/05/02	17,909	-3.9	20,402	0.9	116,452	3.5	65.2
2003	08/21/03	19,688	-3.5	01/23/03	19,454	8.6	19,688	-3.5	114,791	-1.4	66.6
2004	08/03/04	19,145	-2.8	01/23/04	18,958	-2.5	19,706	0.1	116,932	1.9	67.6
2005	07/26/05	20,855	8.9	01/18/05	19,877	4.8	20,855	5.8	121,075	3.5	66.3
2006	08/02/06	21,950	5.3	12/20/05	19,649	-1.1	21,950	5.3	122,161	0.9	63.5
2007	08/08/07	22,429	2.2	02/06/07	21,734	10.6	22,429	2.2	130,688	7.0	66.5
2008	06/09/08	21,635	-3.5	01/25/08	22,005	1.2	22,005	-1.9	131,594	0.7	68.1
2009	08/10/09	19,901	-8.0	01/16/09	22,295	1.3	22,295	1.3	121,002	-8.0	62.0
2010	07/23/10	21,259	6.8	01/11/10	20,360	-8.7	21,259	-4.6	126,125	4.2	67.7
2011*	07/21/11	22,200	4.4	12/14/10	20,605	1.2	22,200	4.4	125,874	-0.2	64.5
Forecast											
2012		21,264	-4.2		20,895	1.4	21,264	-4.2	127,117	1.0	68.2
2013		21,474	1.0		21,172	1.3	21,474	1.0	128,161	0.8	68.1
2014		21,508	0.2		21,172	0.0	21,508	0.2	128,055	-0.1	68.0
2015		21,531	0.1		21,151	-0.1	21,531	0.1	127,890	-0.1	67.8
2016		21,521	0.0		21,083	-0.3	21,521	0.0	127,885	0.0	67.8
2017		21,585	0.3		21,065	-0.1	21,585	0.3	127,921	0.0	67.7
2018		21,668	0.4		21,096	0.1	21,668	0.4	128,107	0.1	67.5
2019		21,750	0.4		21,136	0.2	21,750	0.4	128,260	0.1	67.3
2020		21,780	0.1		21,082	-0.3	21,780	0.1	128,449	0.1	67.3
2021		21,949	0.8		21,275	0.9	21,949	0.8	129,004	0.4	67.1
2022		22,076	0.6		21,370	0.4	22,076	0.6	129,564	0.4	67.0
2023		22,175	0.4		21,365	0.0	22,175	0.4	130,139	0.4	67.0
2024		22,275	0.5		21,390	0.1	22,275	0.5	130,774	0.5	67.0
2025		22,492	1.0		21,600	1.0	22,492	1.0	131,473	0.5	66.7
2026		22,672	0.8		21,748	0.7	22,672	0.8	132,298	0.6	66.6
2027		22,874	0.9		21,903	0.7	22,874	0.9	133,275	0.7	66.5
2028		23,043	0.7		21,997	0.4	23,043	0.7	134,339	0.8	66.6
2029		23,258	0.9		22,133	0.6	23,258	0.9	135,313	0.7	66.4
2030		23,481	1.0		22,306	0.8	23,481	1.0	136,375	0.8	66.3
2031		23,712	1.0		22,498	0.9	23,712	1.0	137,494	0.8	66.2

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

Exhibit 3-10

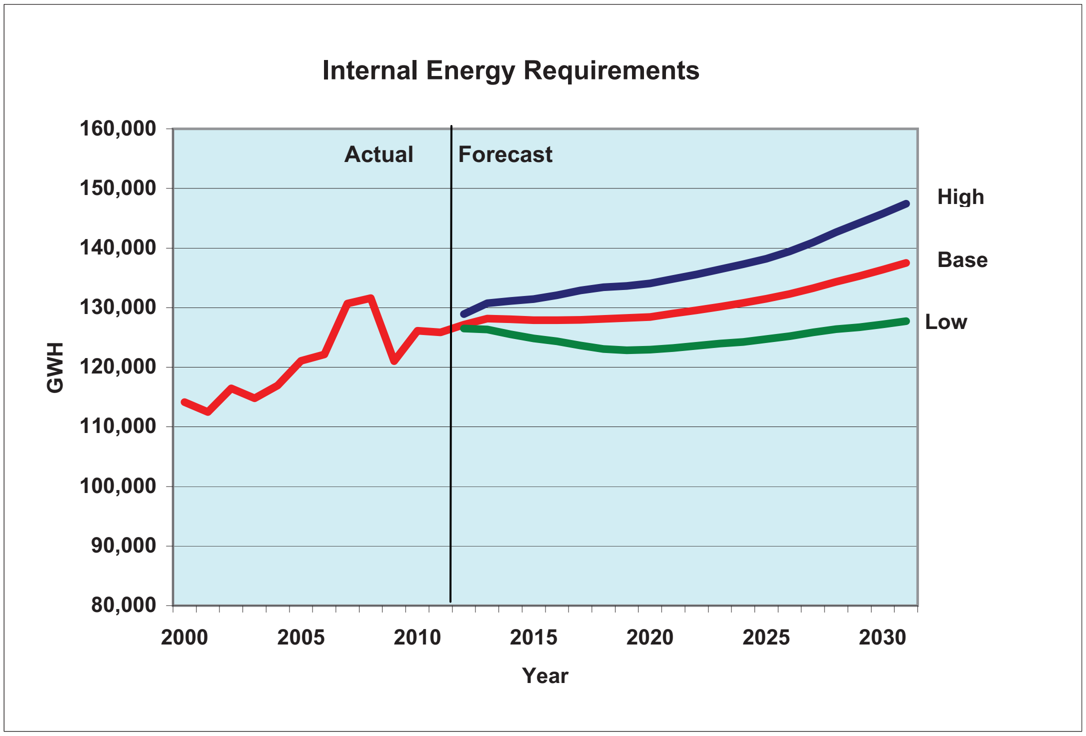
AEP System - East Zone
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements

	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**
2012	20,793	20,895	21,189	21,161	21,264	21,563	126,497	127,117	128,904
2013	20,873	21,172	21,599	21,171	21,474	21,906	126,355	128,161	130,745
2014	20,753	21,172	21,681	21,081	21,508	22,025	125,517	128,055	131,135
2015	20,642	21,151	21,735	21,014	21,531	22,126	124,816	127,890	131,421
2016	20,498	21,083	21,774	20,924	21,521	22,226	124,336	127,885	132,076
2017	20,366	21,065	21,879	20,868	21,585	22,420	123,672	127,921	132,865
2018	20,266	21,096	21,973	20,815	21,668	22,568	123,066	128,107	133,430
2019	20,246	21,136	22,023	20,834	21,750	22,663	122,861	128,260	133,644
2020	20,181	21,082	22,001	20,850	21,780	22,729	122,960	128,449	134,046
2021	20,321	21,275	22,235	20,965	21,949	22,939	123,217	129,004	134,823
2022	20,382	21,370	22,360	21,055	22,076	23,099	123,574	129,564	135,567
2023	20,352	21,365	22,398	21,123	22,175	23,246	123,965	130,139	136,426
2024	20,321	21,390	22,454	21,162	22,275	23,383	124,237	130,774	137,279
2025	20,494	21,600	22,706	21,341	22,492	23,644	124,745	131,473	138,210
2026	20,584	21,748	22,922	21,459	22,672	23,896	125,216	132,298	139,440
2027	20,685	21,903	23,160	21,601	22,874	24,187	125,863	133,275	140,925
2028	20,696	21,997	23,358	21,680	23,043	24,469	126,389	134,339	142,649
2029	20,726	22,133	23,592	21,780	23,258	24,791	126,710	135,313	144,229
2030	20,801	22,306	23,841	21,896	23,481	25,097	127,170	136,375	145,758
2031	20,903	22,498	24,126	22,031	23,712	25,428	127,745	137,494	147,440
Average Annual Growth Rate % - 2010-2029									
	0.0	0.4	0.7	0.2	0.6	0.9	0.1	0.4	0.7

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**
2012	3,913	3,932	3,987	4,505	4,527	4,590	26,041	26,169	26,537
2013	3,950	4,007	4,087	4,548	4,613	4,706	26,246	26,621	27,158
2014	3,909	3,988	4,084	4,506	4,597	4,707	25,974	26,500	27,137
2015	3,868	3,963	4,072	4,469	4,579	4,706	25,733	26,366	27,094
2016	3,821	3,930	4,058	4,432	4,558	4,708	25,516	26,244	27,104
2017	3,785	3,915	4,066	4,408	4,560	4,736	25,289	26,158	27,169
2018	3,741	3,894	4,056	4,371	4,550	4,739	25,014	26,039	27,120
2019	3,714	3,878	4,040	4,354	4,545	4,736	24,863	25,956	27,046
2020	3,691	3,856	4,024	4,342	4,536	4,733	24,800	25,907	27,036
2021	3,701	3,874	4,049	4,358	4,563	4,768	24,813	25,978	27,150
2022	3,702	3,882	4,062	4,369	4,580	4,793	24,840	26,044	27,251
2023	3,703	3,888	4,075	4,386	4,605	4,827	24,912	26,152	27,416
2024	3,703	3,898	4,092	4,396	4,628	4,858	24,993	26,308	27,617
2025	3,733	3,935	4,136	4,437	4,676	4,916	25,129	26,484	27,841
2026	3,747	3,959	4,173	4,461	4,713	4,968	25,232	26,659	28,098
2027	3,762	3,983	4,212	4,485	4,750	5,022	25,342	26,834	28,374
2028	3,764	4,000	4,248	4,497	4,780	5,075	25,424	27,023	28,695
2029	3,773	4,029	4,294	4,521	4,828	5,146	25,485	27,215	29,008
2030	3,783	4,057	4,336	4,541	4,870	5,205	25,566	27,416	29,303
2031	3,798	4,088	4,384	4,564	4,912	5,268	25,663	27,622	29,620
Average Annual Growth Rate % - 2010-2029									
	-0.2	0.2	0.5	0.1	0.4	0.7	-0.1	0.3	0.6

AEP System - East Zone
Range of Forecasts



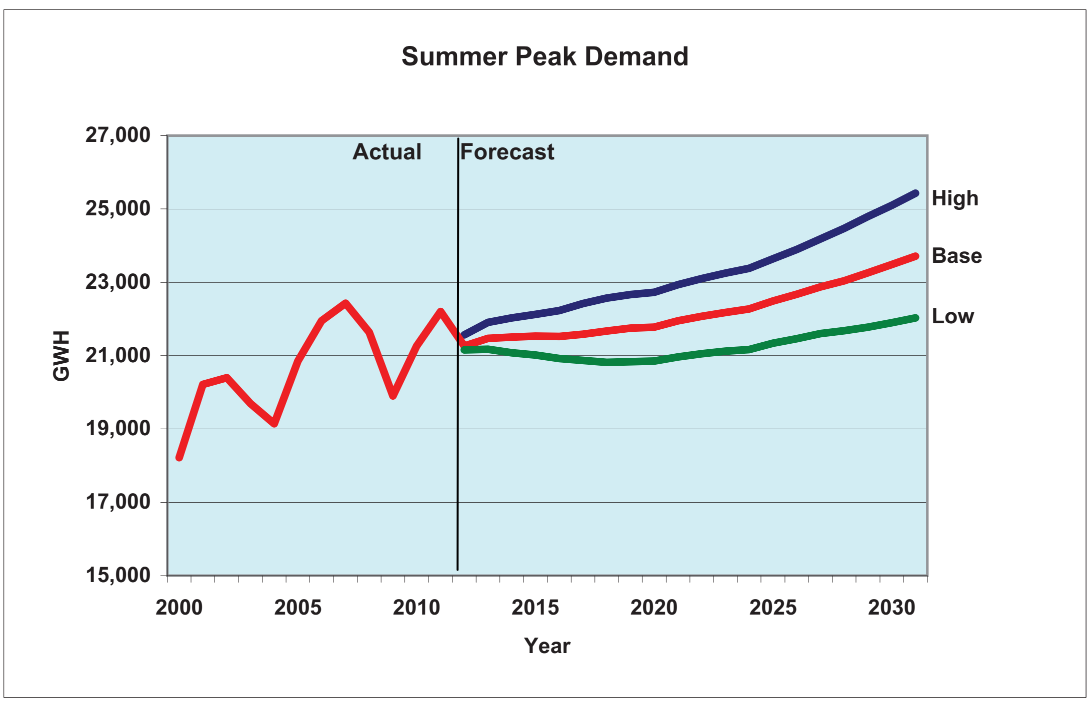
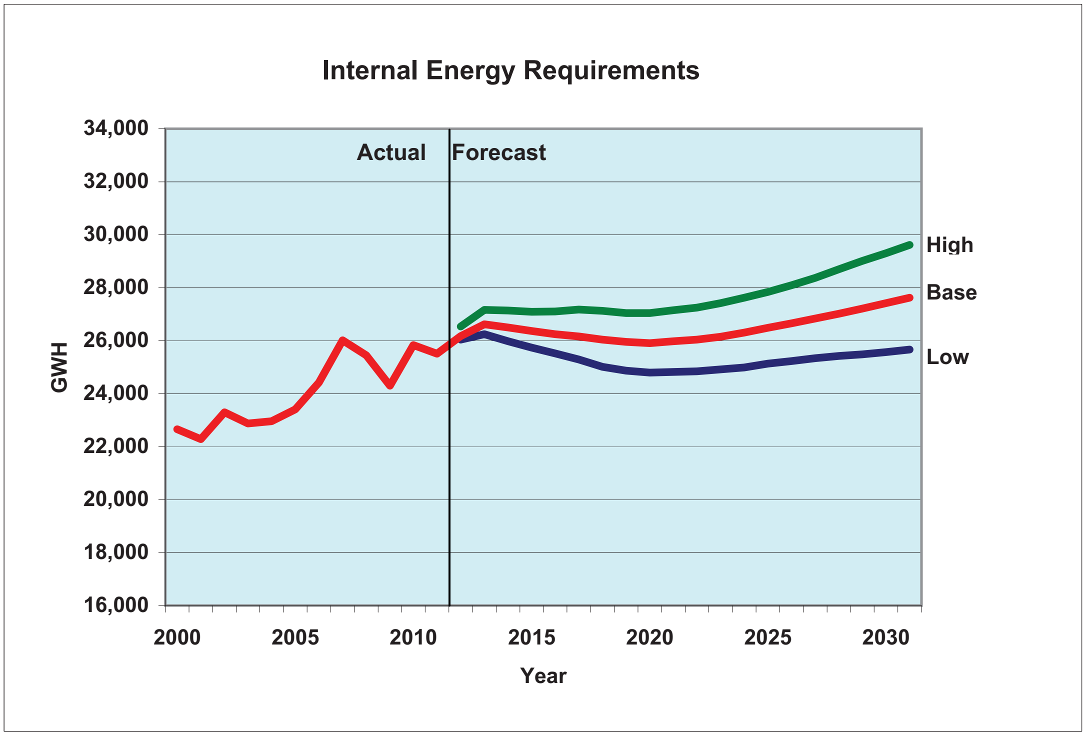
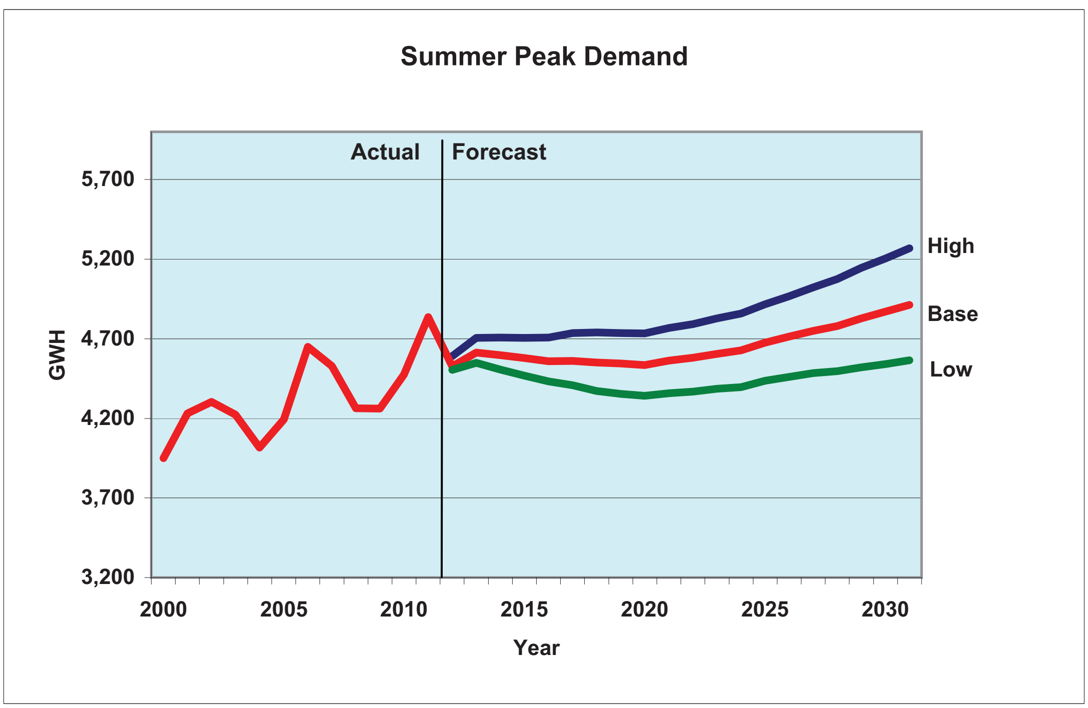


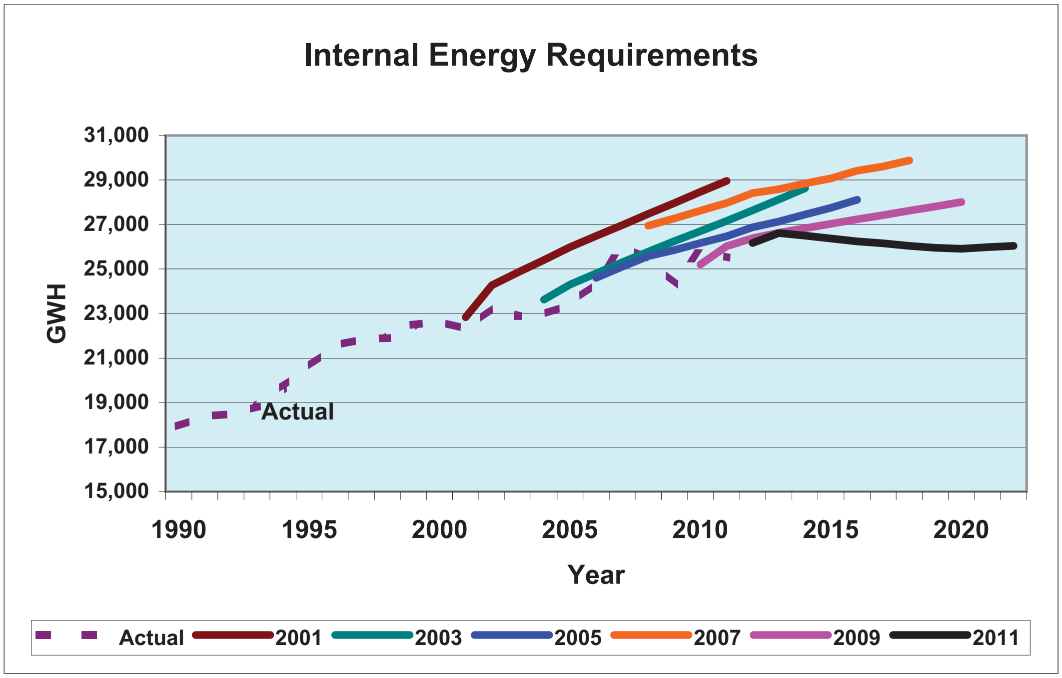
Exhibit 3-13

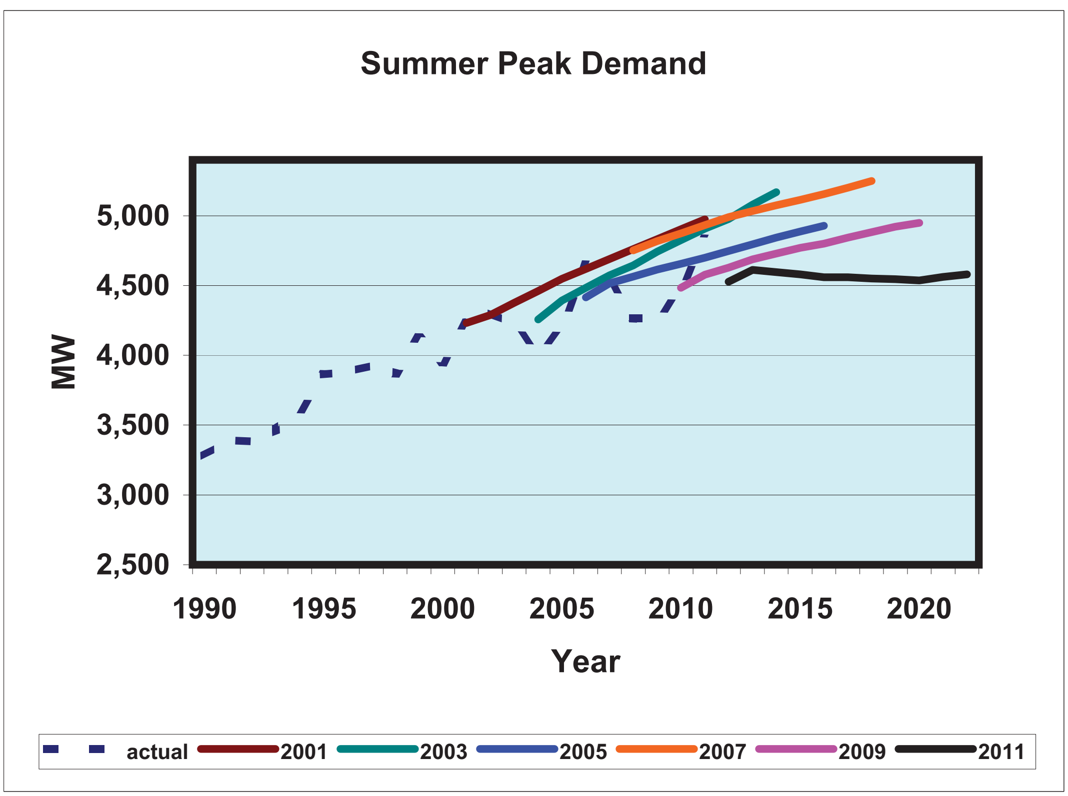
Indiana Michigan Power Company
Range of Forecasts



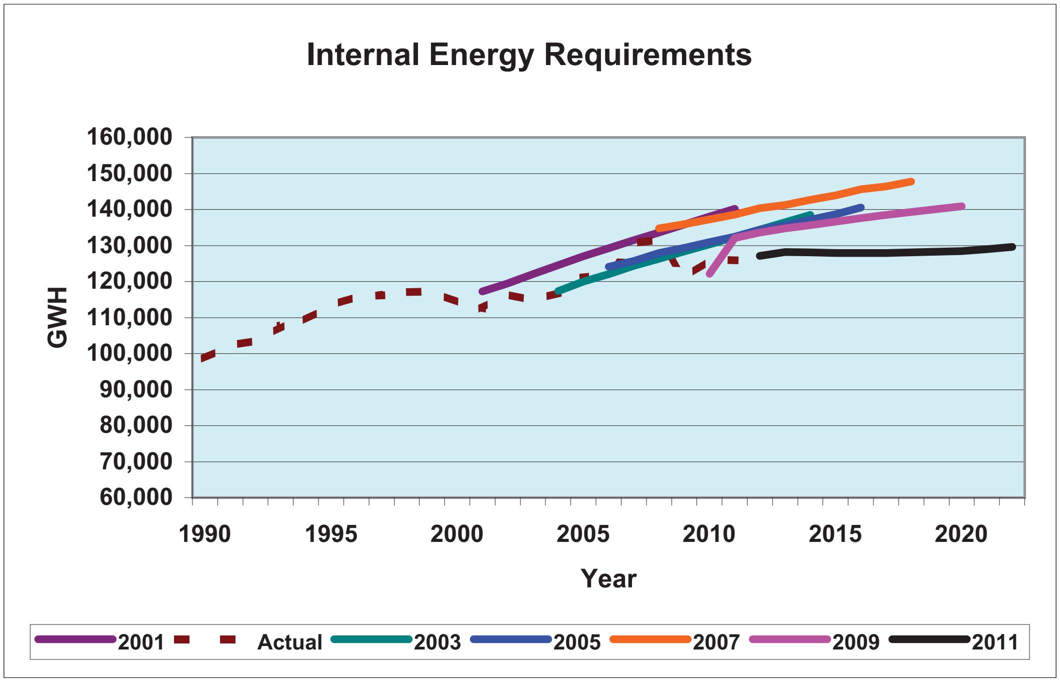


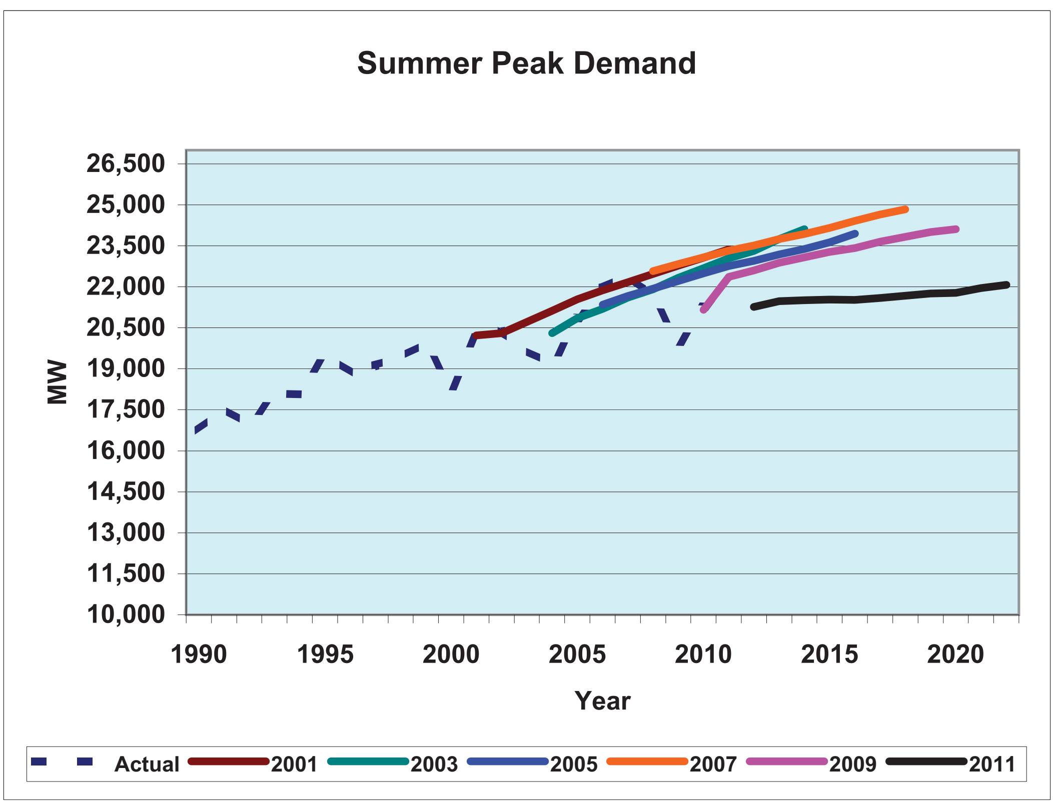
INDIANA MICHIGAN POWER COMPANY
COMPARISON OF FORECASTS





AEP System - East Zone
COMPARISON OF FORECASTS

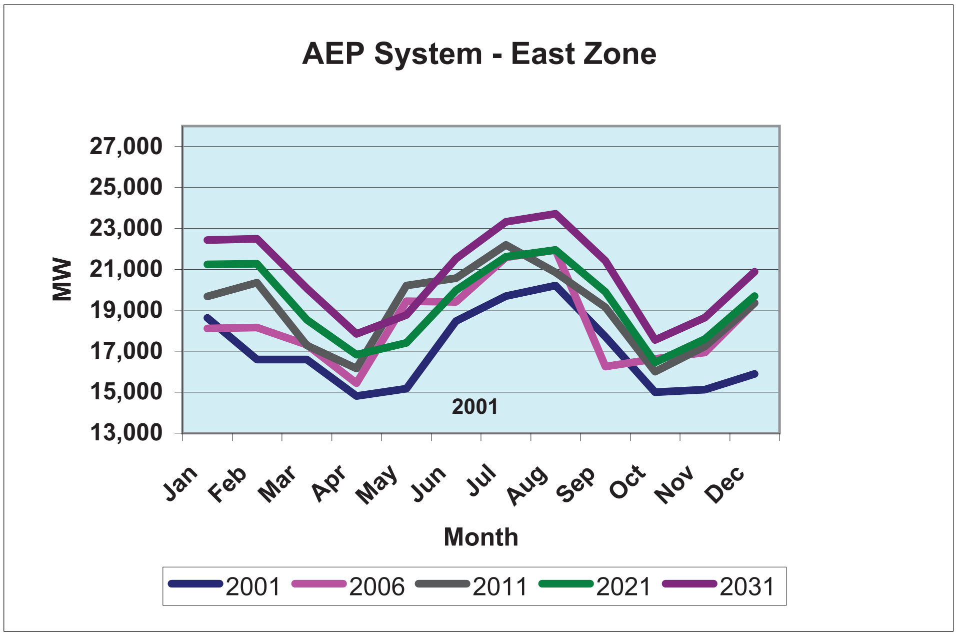


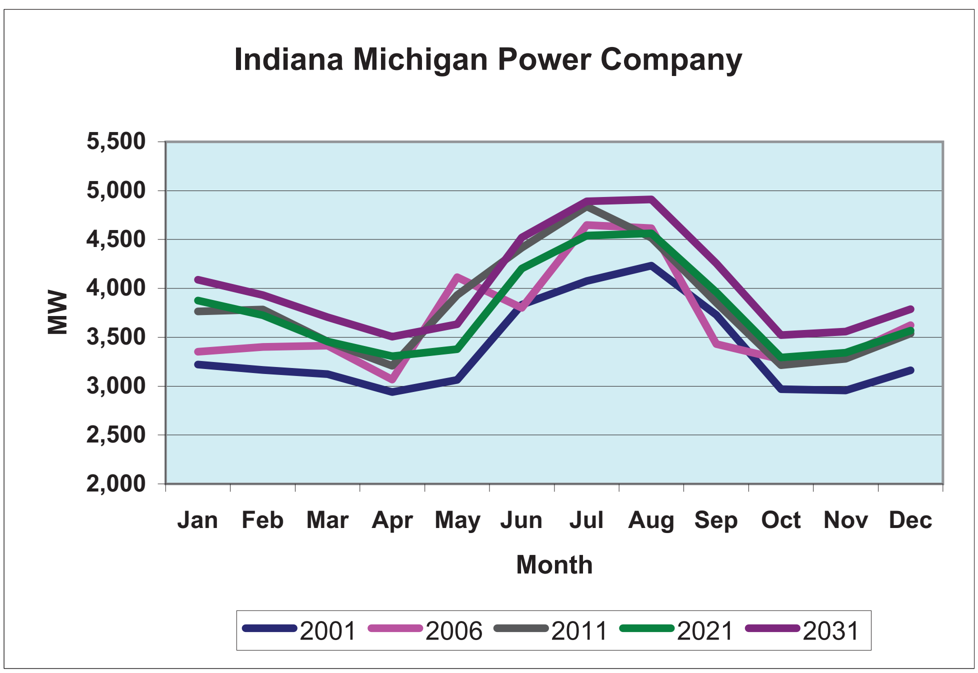


Indiana Michigan Power Company and AEP System - East Zone
Recorded and Weather Normalized Peak Load (MW) and Energy (GWh)
2001-2010

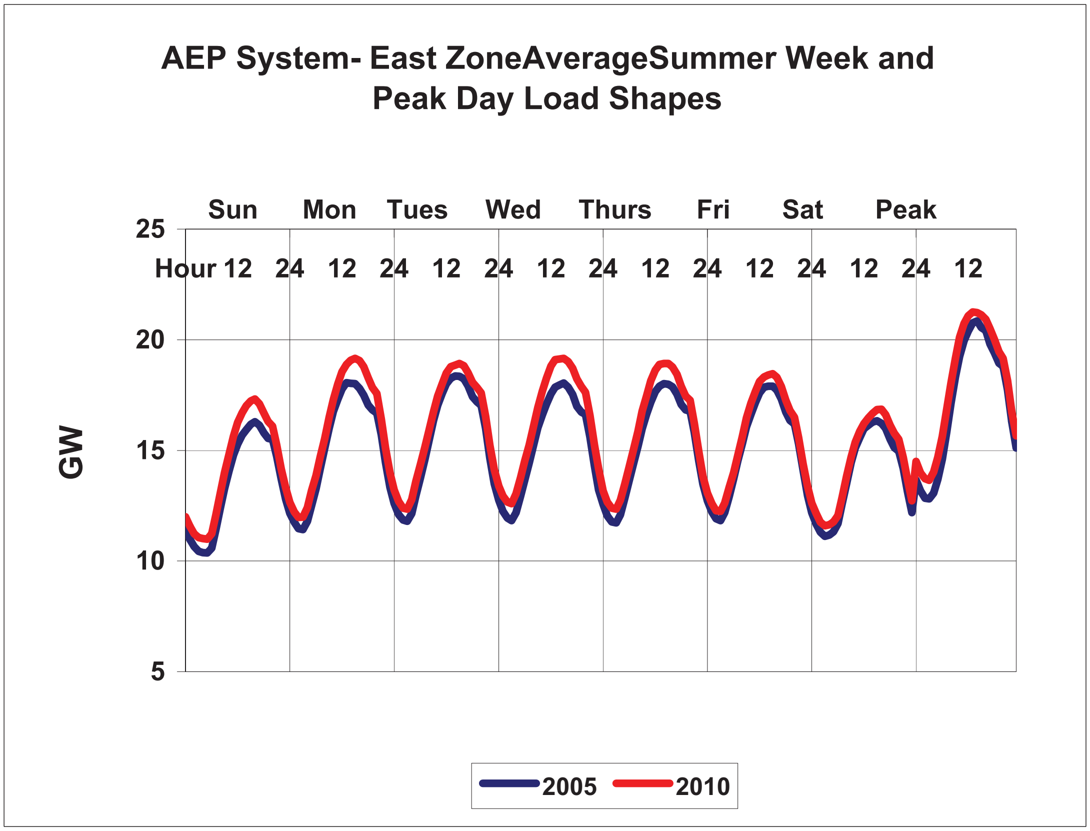
		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Indiana Michigan Power Company											
A.	**Peak Load - Summer**										
	1. Recorded	4,232	4,303	4,223	4,016	4,193	4,650	4,528	4,264	4,262	4,474
	2. Weather - Normalized	4,017	4,194	4,177	4,176	4,225	4,373	4,544	4,400	3,943	4,404
B.	**Peak Load - Preceding Winter**										
	1. Recorded	3,393	3,258	3,683	3,465	3,465	3,537	3,945	3,875	3,728	3,858
	2. Weather - Normalized	3,438	3,165	3,596	3,550	3,548	3,383	3,745	3,889	3,713	3,647
C.	**Energy**										
	1. Recorded	22,284	23,293	22,876	22,962	23,407	24,419	26,013	25,448	24,296	25,828
	2. Weather - Normalized	22,365	23,030	23,137	23,266	23,111	24,764	25,774	25,488	24,644	25,365
AEP System - East Zone											
A.	**Peak Load - Summer**										
	1. Recorded	20,218	20,402	19,688	19,145	20,855	21,950	22,429	21,635	19,901	21,259
	2. Weather - Normalized	19,385	19,623	20,055	19,719	20,520	20,611	21,654	20,434	20,328	20,918
B.	**Peak Load - Preceding Winter**										
	1. Recorded	18,634	17,909	19,454	18,958	19,877	19,649	21,734	22,005	22,295	20,360
	2. Weather - Normalized	18,949	18,278	19,136	19,403	19,624	18,642	20,064	21,157	20,814	20,228
C.	**Energy**										
	1. Recorded	112,482	116,452	114,791	116,932	121,075	122,161	130,688	131,594	121,002	126,125
	2. Weather - Normalized	113,484	115,135	115,813	117,890	119,754	123,807	128,824	131,414	121,964	123,320

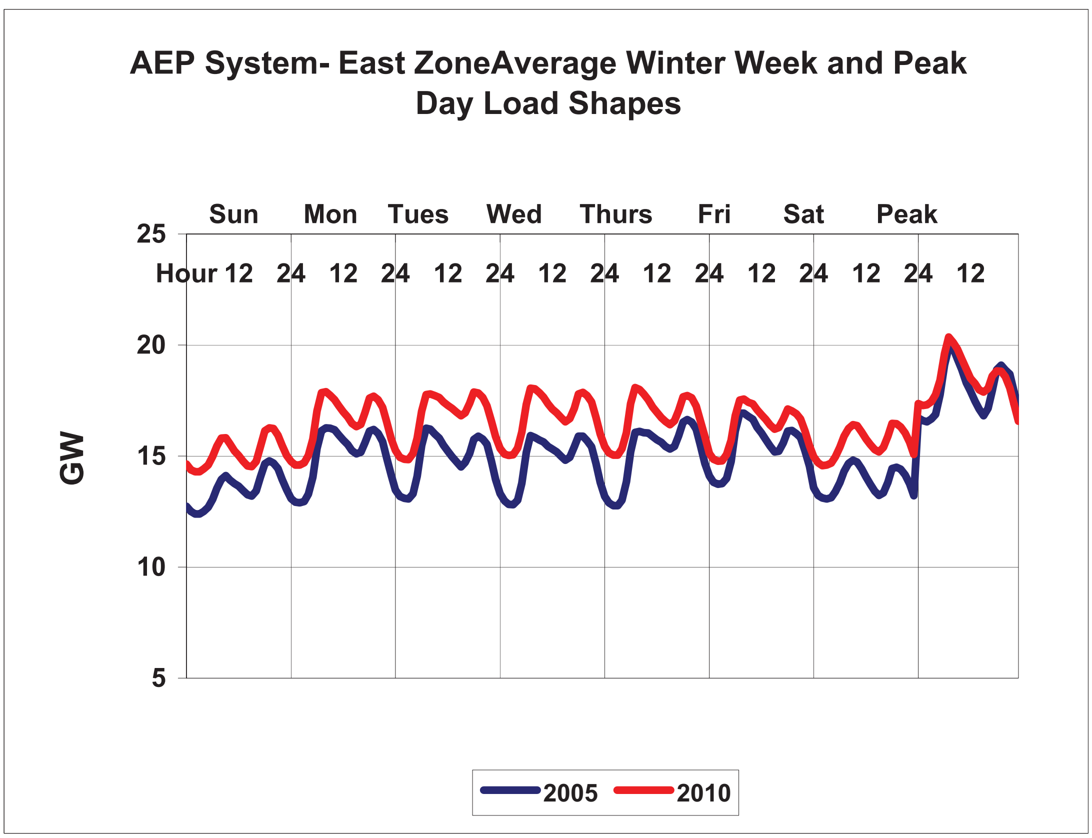
AEP System - East Zone and Indiana Michigan Power Company
Profiles of Monthly Peak Internal Demands
2001, 2006, 2011* (Actual)
2021 and 2031

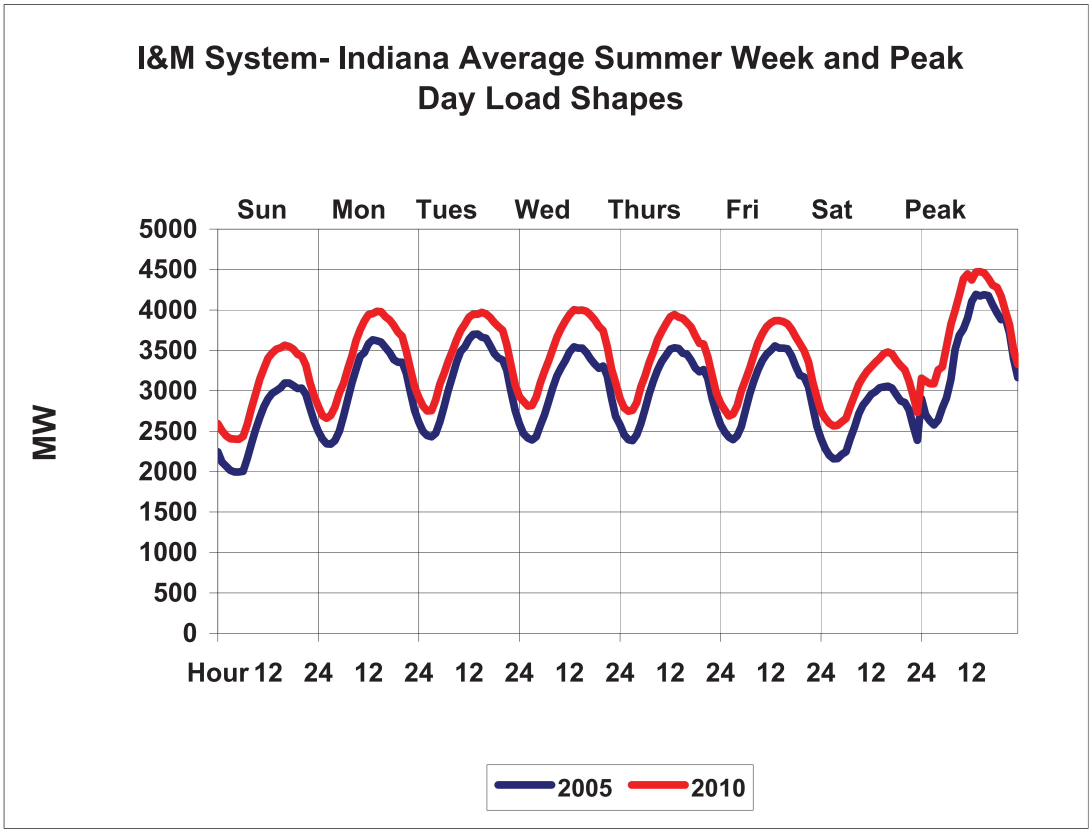


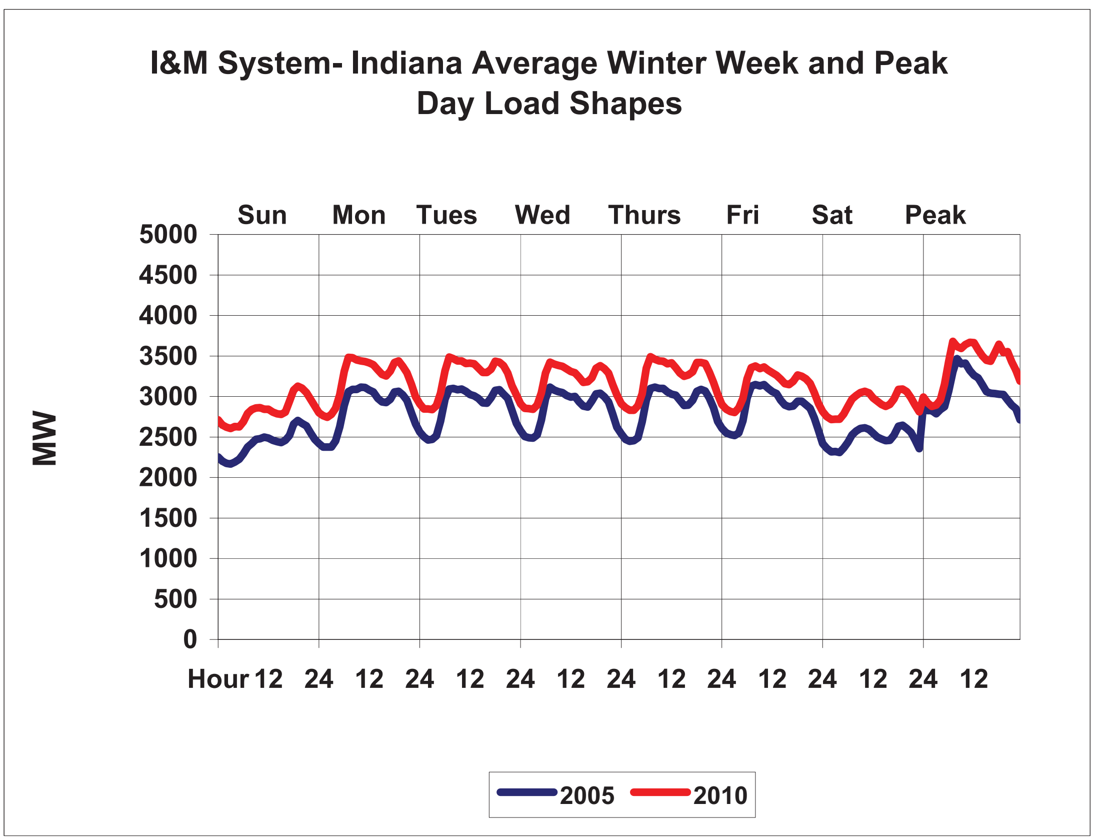


***Data for 2011 include eight months actual and four month forecast.**


AEP System- East ZoneAverageSummer Week and Peak Day Load Shapes
Sun Mon Tues Wed Thurs Fri Sat Peak
Hour 12 24 12 24 12 24 12 24 12 24 12 24 12 24 12
25
20
15
10
5
GW
2005
2010


AEP System- East ZoneAverage Winter Week and Peak Day Load Shapes
Sun Mon Tues Wed Thurs Fri Sat Peak
Hour 12 24 12 24 12 24 12 24 12 24 12 24 12 24 12
25
20
15
10
5
GW
2005
2010


I&M System- Indiana Average Summer Week and Peak Day Load Shapes
Sun
Mon
Tues
Wed
Thurs
Fri
Sat
Peak
MW
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
Hour 12 24 12 24 12 24 12 24 12 24 12 24 12 24 12
2005
2010


I&M System- Indiana Average Winter Week and Peak Day Load Shapes
Sun
Mon
Tues
Wed
Thurs
Fri
Sat
Peak
MW
5000
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2500
2000
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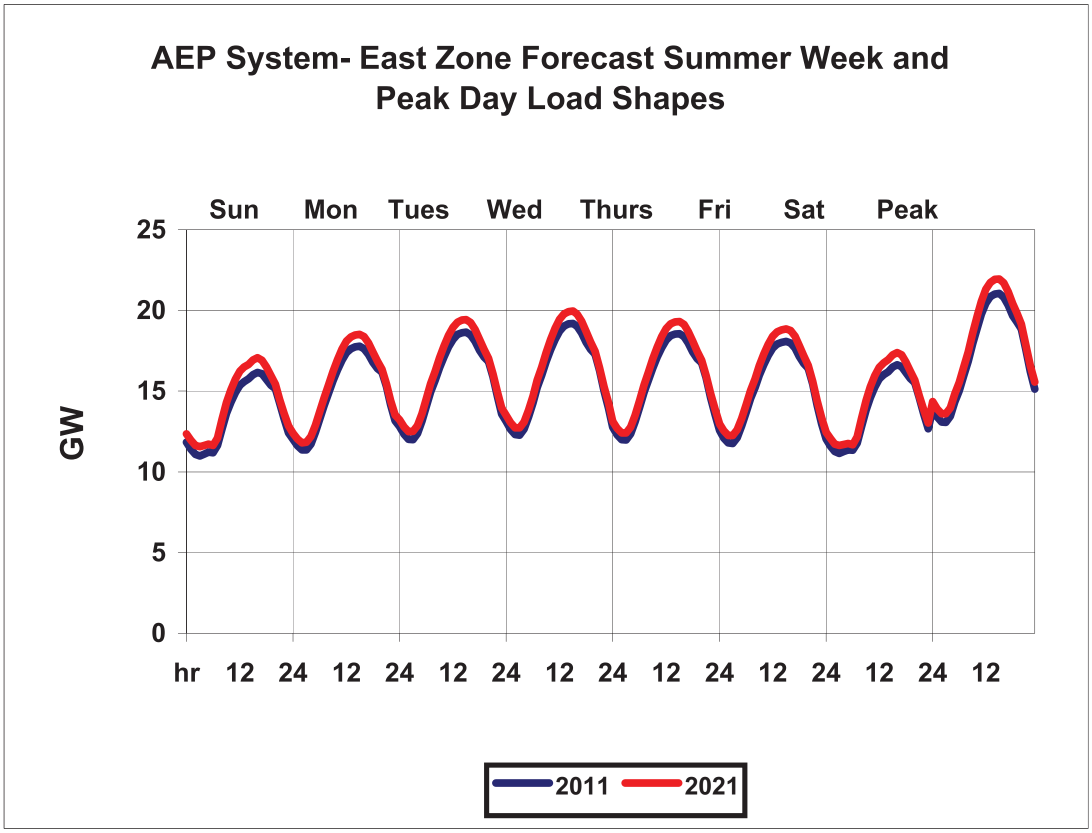
Hour 12 24 12 24 12 24 12 24 12 24 12 24 12 24 12
2005
2010


AEP System- East Zone Forecast Summer Week and
Peak Day Load Shapes
Sun
Mon
Tues
Wed
Thurs
Fri
Sat
Peak
GW
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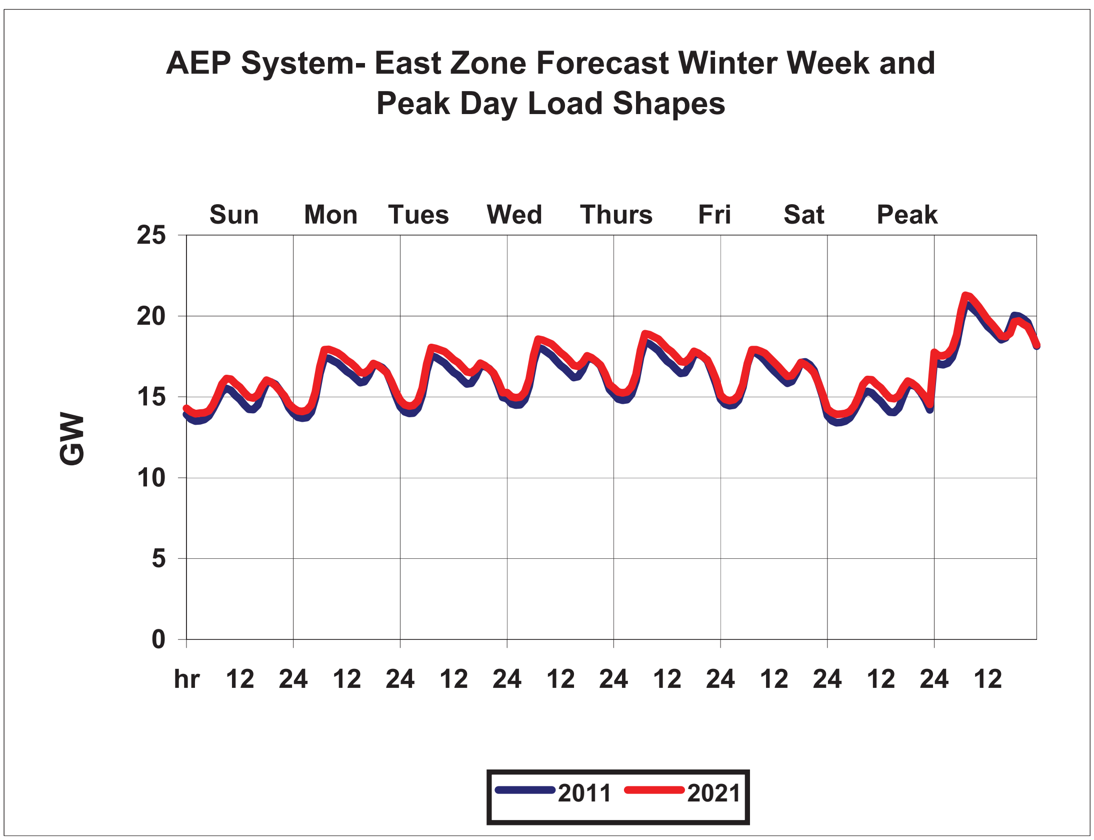
12
24
12
24
12
2011
2021


AEP System- East Zone Forecast Winter Week and
Peak Day Load Shapes
Sun
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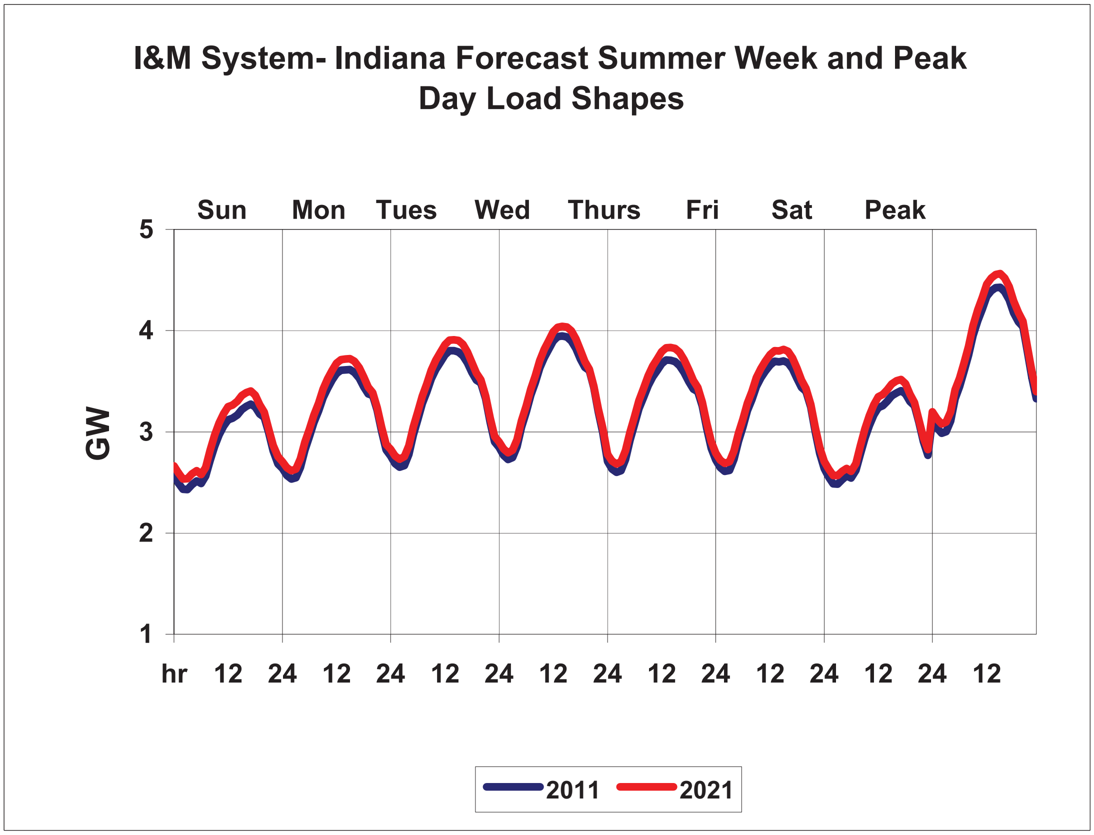
12
2011
2021


I&M System- Indiana Forecast Summer Week and Peak
Day Load Shapes
Sun
Mon
Tues
Wed
Thurs
Fri
Sat
Peak
GW
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3
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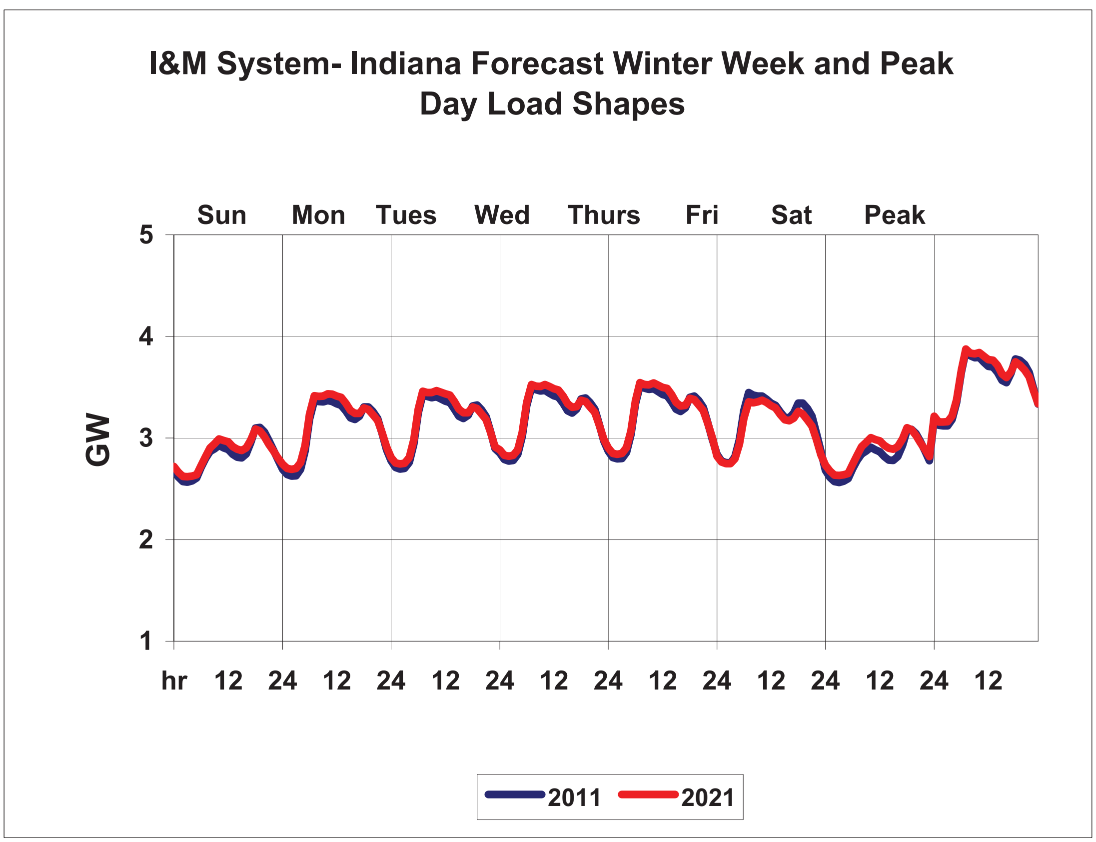
2011
2021


I&M System- Indiana Forecast Winter Week and Peak
Day Load Shapes
Sun
Mon
Tues
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Thurs
Fri
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Peak
GW
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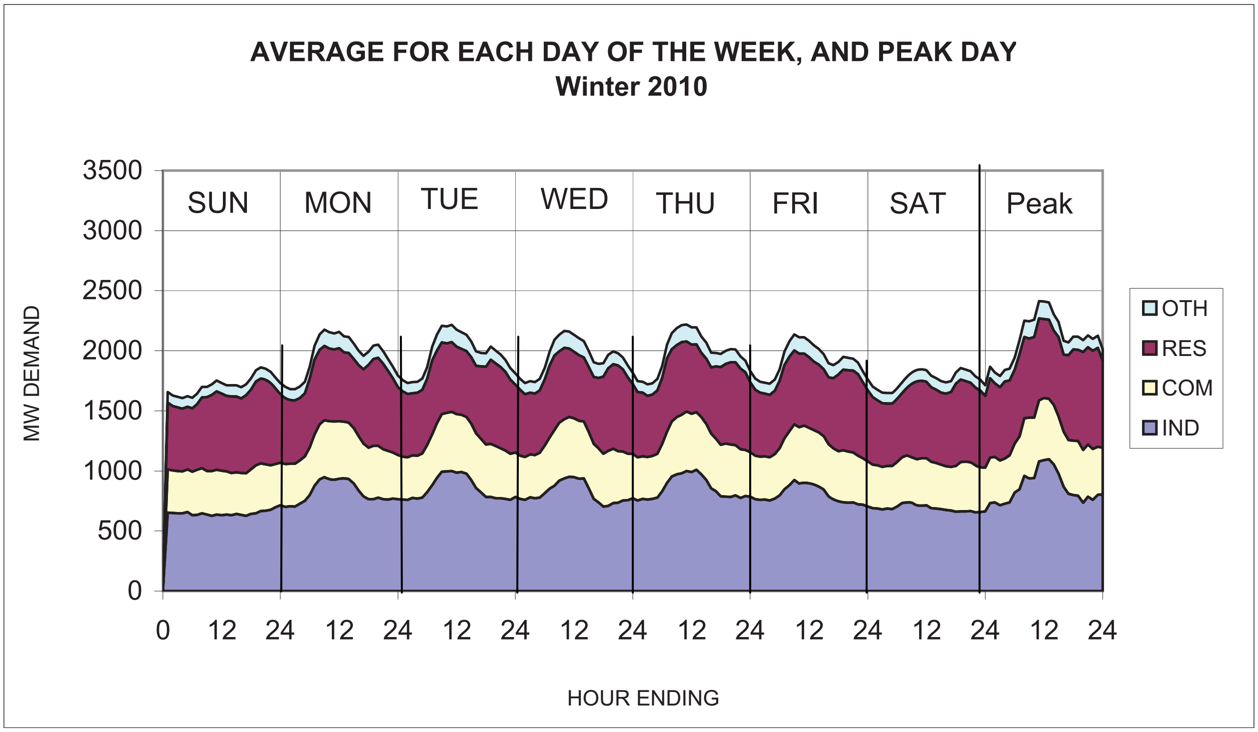
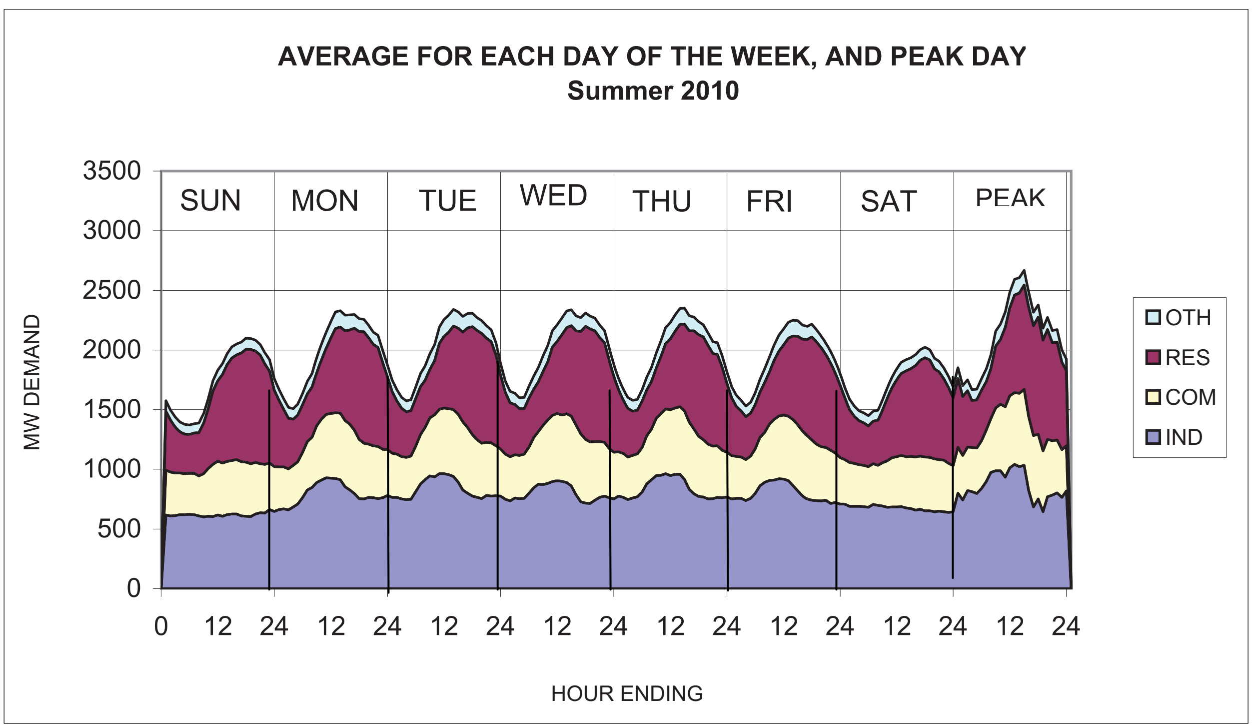
24
12
2011
2021

I&M - INDIANA JURISDICTION HOURLY DEMAND BY CLASS





INDIANA MICHIGAN POWER COMPANY LOAD FORECAST DATA SOURCES OUTSIDE THE COMPANY					
DATA SERIES	FREQUENCY	GEOGRAPHIC	INTERVAL	SOURCE	,
Average Daily Temperatures at time of Daily Peak Load	Daily	Selected weather stations throughout the AEP System	1984-2010	NOAA (1) Weather Bank	None
Heating and Cooling Degree-Days	Monthly	Selected weather stations throughout the AEP System	1/84-9/10	NOAA (1) Weather Bank	
Gross Regional Product, Manufacturing	Quarterly	U. S.	1984-2040	Moody's Analytics (2)	None
CPI-All Urban Wage Earners	Quarterly	U. S.	1975:1-2040:4	Moody's Analytics (2)	
U.S. Gas Prices, U.S. Gas Consumption	Annually	U.S.	1975-2035	DOE/EIA (6)	Growth rate historical da
Index of Producer Prices-Industrial Commodities	Quarterly	U. S.	1975:1-2040:4	Moody's Analytics (2)	Annual aver long-term m
Residential Appliance Efficiencies, Saturation Trends, Housing Size	Annual, Monthly	East North Central Census Region	1980-2035	DOE via Itron(7) Itron	Extrapolate trends to Co
Commericial Equipment Efficiencies, Saturations Square-Footage	Annual, Monthly	East North Central Census Region	1980-2035	DOE via Itron(8) Itron	Extrapolate
U. S., Indiana and Michigan Natural Gas Prices by Sector	Annually	U. S.	1973-2009	DOE/EIA (4)	None
Gross Regional Product	Quarterly	Selected Indiana and Michigan Counties	1975-2040	Moody's Analytics (5)	None
Employment (Total and Selected Sectors), Personal Income and Population	Quarterly	Selected Indiana and Michigan Counties	1975-2040	Moody's Analytics (5)	None

Source Citations:

(1) "Local Climatological Data," National Oceanographic and Atmospheric Administration.
(2) October 2010 Forecast, Moody's Analytics
(3) Board of Governors of Federal Reserve System, "Federal Reserve Statistical Release," 1975-2010
(4) U. S. Department of Energy/Energy Information Administration "Natural Gas Monthly" and "Natrual Gas Annual," Selected Issues.
(5) October 2010 Regional Forecast, Moody's Analytics
(6) U.S. Department of Energy/Energy Information Administration "Annual Energy Outlook 2010 with Projections to 2035" April 2010

AEP SYSTEM - EAST ZONE
AND INDIANA MICHIGAN POWER COMPANY
GENERATING CAPACITY IN SERVICE (A)

			CAPABILITY - MW			
			AEP SYSTEM		I&M (B)	
PLANT	**UNITS**	**NOTES**	**Winter** (H)	**Summer** (G)	**Winter** (H)	**Summer** (G)
John E. Amos	1-3		2,900	2,865	-	-
W. C. Beckjord	6	(C)	52	52	-	-
Big Sandy	1-2		1,078	1,078	-	-
Cardinal	1		595	585	-	-
Ceredo (Gas)	1-6		516	450	-	-
Clinch River	1-3		705	690	-	-
Conesville	3,5-6		965	965	-	-
Conesville	4	(C)	337	337	-	-
Cook Nuclear	1-2		2,191	2,059	2,191	2,059
Darby (Gas)	1-6		507	438	-	-
Gen. J. M. Gavin	1-2		2,640	2,630	-	-
Glen Lyn	5-6		335	325	-	-
Kammer	1-3		630	400	-	-
Kanawha River	1-2		400	400	-	-
Lawrenceburg (Gas)	1-6		1,186	1,120	-	-
Mitchell	1-2		1,560	1,560	-	-
Mountaineer	1		1,320	1,305	-	-
Muskingum River	1-5		1,440	1,375	-	-
Picway	5		100	95	-	-
Rockport	1-2		2,620	2,615	2,227	2,223
Smith Mtn. (Pumped Storage)	1-5		586	586	-	-
Sporn	1-5		1,050	580	-	-
J. M. Stuart	1-4	(C)	604	604	-	-
J. M. Stuart (Diesel)	1-4	(C)	3	3	-	-
Tanners Creek	1-4		995	985	995	985
Waterford (Gas)	1-4		840	810	-	-
W. H. Zimmer	1	(C)	330	330	-	-
Conventional Hydro			133	98	15	12
Total Excl. Buckeye			26,618	25,340	5,428	5,279
Cardinal (Buckeye Power)	2-3	(D)	1,225	1,215	-	-
Total Incl. Buckeye			27,843	26,555	5,428	5,279
Capacity Purchases						
Clifty & Kyger (OVEC)	1-6	(E)	980	947	177	171
Beach Ridge (Wind)		(I)	13	13	-	-
Camp Grove (Wind)		(I)	17	20	-	-
Fowler Ridge Phase 1 & 3 (Wind)		(I)	31	36	16	17
Grand Ridge Phase 2 & 3 (Wind)		(I)	13	19	-	-
Fowler Ridge Phase 2 (Wind)		(I)	20	24	7	8
Wyandotte (Solar)		(I)	1	4	-	-
Robert Mone (Gas)	1-3	(F)	135	49	26	9
Constellation Energy (Gas)			315	315	61	61
SEPA (Hydro)			4	4	1	1
Summersville (Hydro)			28	14	-	-
Total Purchases			1,556	1,445	287	267
Total Incl. Buckeye and Purchases			29,398	27,999	5,715	5,546

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. Capability shown reflects CSP's share of unit owned jointly with CG&E and DP&L.
D. Cardinal Units 2 and 3 are owned by Buckeye Power, Inc.
E. AEP's and I&M's PPR shares of OVEC purchase.
F. Capability shown for I&M reflects I&M's MLR share of the Mone purchase.
G. Expected capacity at time of AEP and I&M Summer 2011 peaks.
H. Expected capacity at time of AEP and I&M Winter 2010/2011 peaks.
I. Wind and Solar capacity values are assumed to be 13% and 38% of nameplate or based on historical performance.

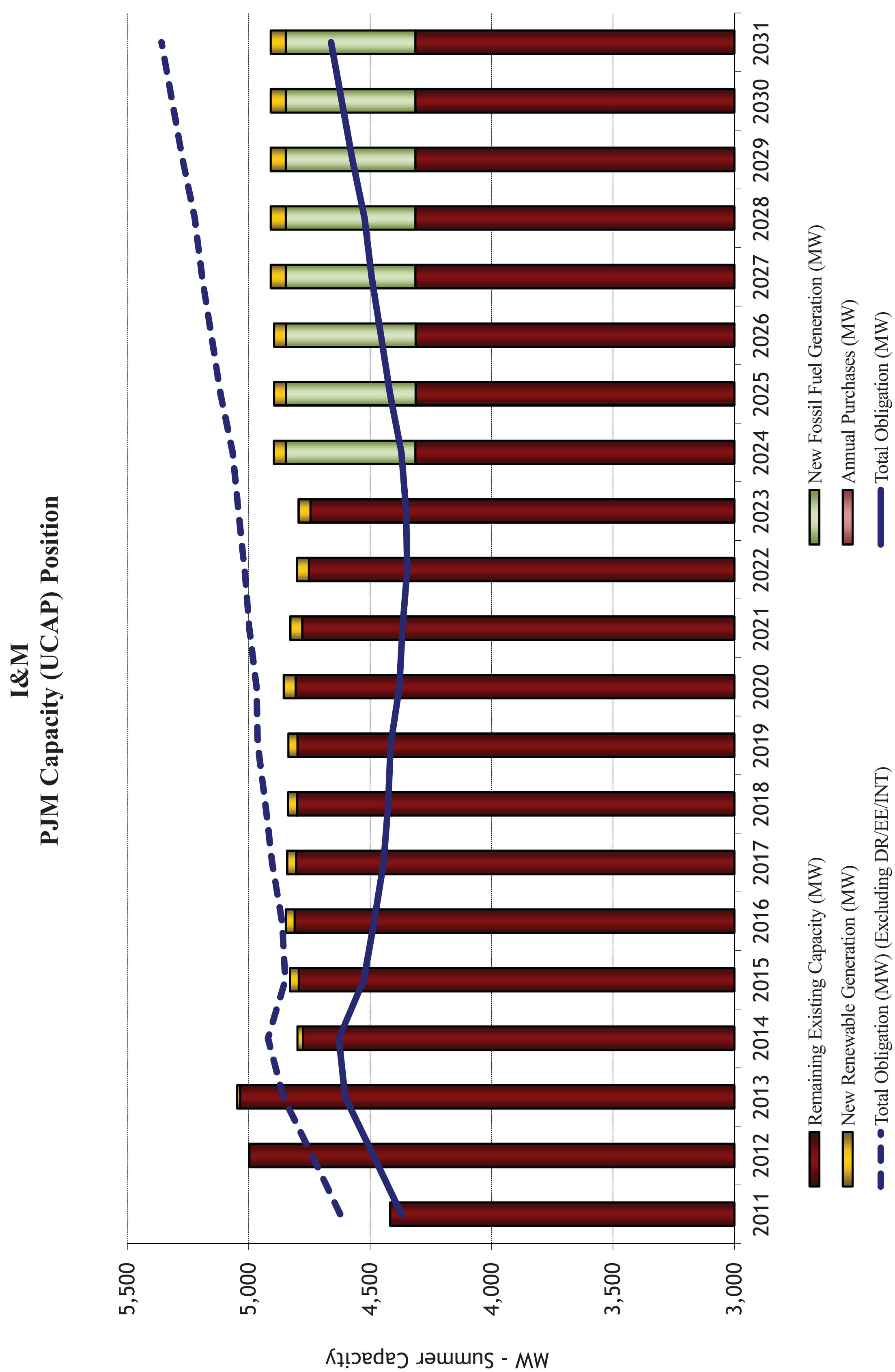
Existing I&M Generating Units (MW)

Summer	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Cook 1	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007
Cook 2	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071
Rockport 1	1,118	1,118	1,118	1,118	1,126	1,126	1,126	1,126	1,126	1,126
Rockport 2	1,105	1,105	1,105	1,105	1,105	1,105	1,105	1,105	1,135	1,135
Tanners 1	145	145	145	0	0	0	0	0	0	0
Tanners 2	145	145	145	0	0	0	0	0	0	0
Tanners 3	195	195	195	0	0	0	0	0	0	0
Tanners 4	500	500	500	500	500	500	500	500	500	500
Unit Total	5,286	5,286	5,286	4,801	4,809	4,809	4,809	4,809	4,839	4,839

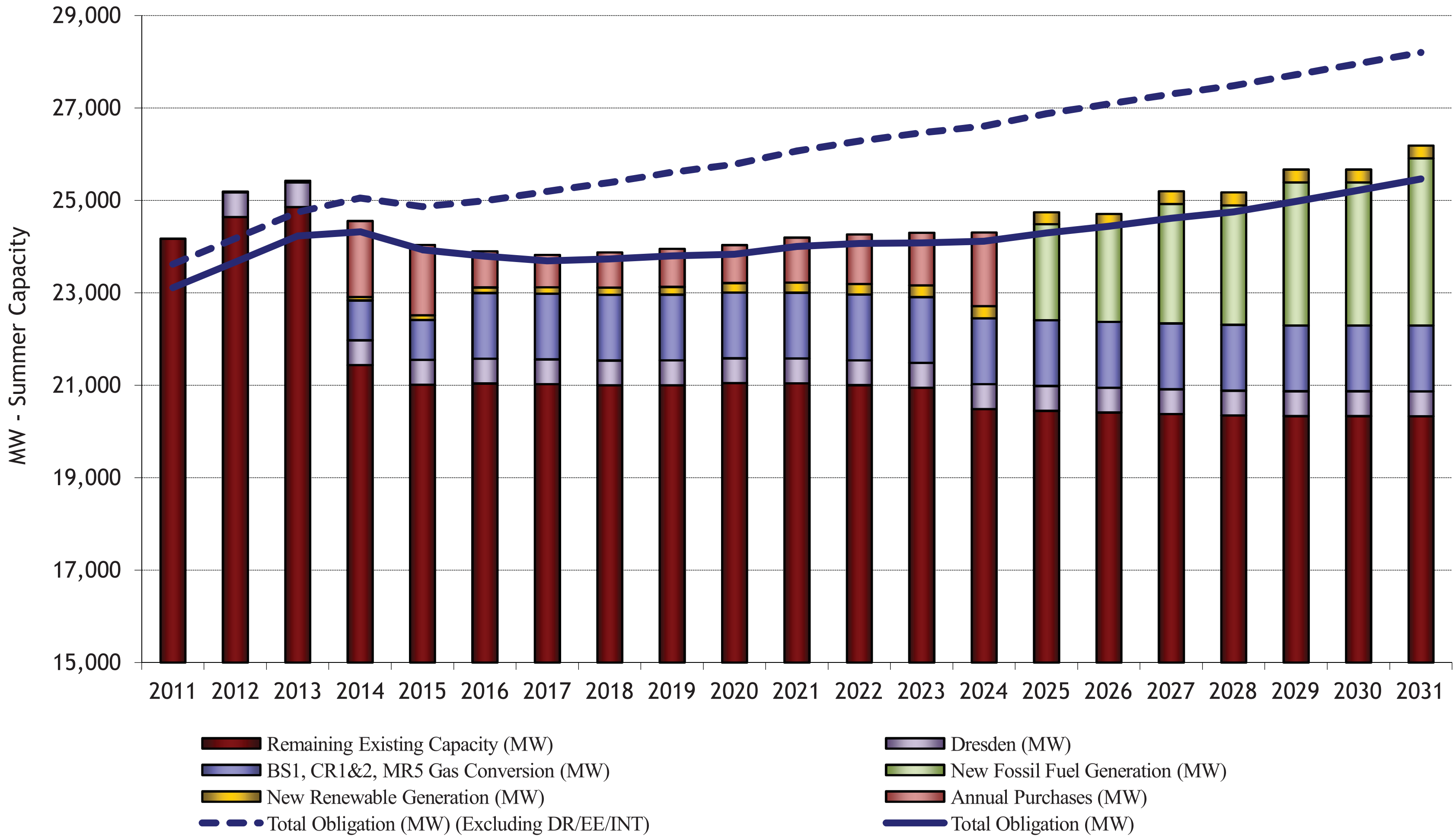
Summer	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Cook 1	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007
Cook 2	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071
Rockport 1	1,126	1,126	1,126	1,126	1,126	1,126	1,126	1,126	1,126	1,126
Rockport 2	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135	1,135
Tanners 1	0	0	0	0	0	0	0	0	0	0
Tanners 2	0	0	0	0	0	0	0	0	0	0
Tanners 3	0	0	0	0	0	0	0	0	0	0
Tanners 4	500	500	500	0	0	0	0	0	0	0
Unit Total	4,839	4,839	4,839	4,339	4,339	4,339	4,339	4,339	4,339	4,339

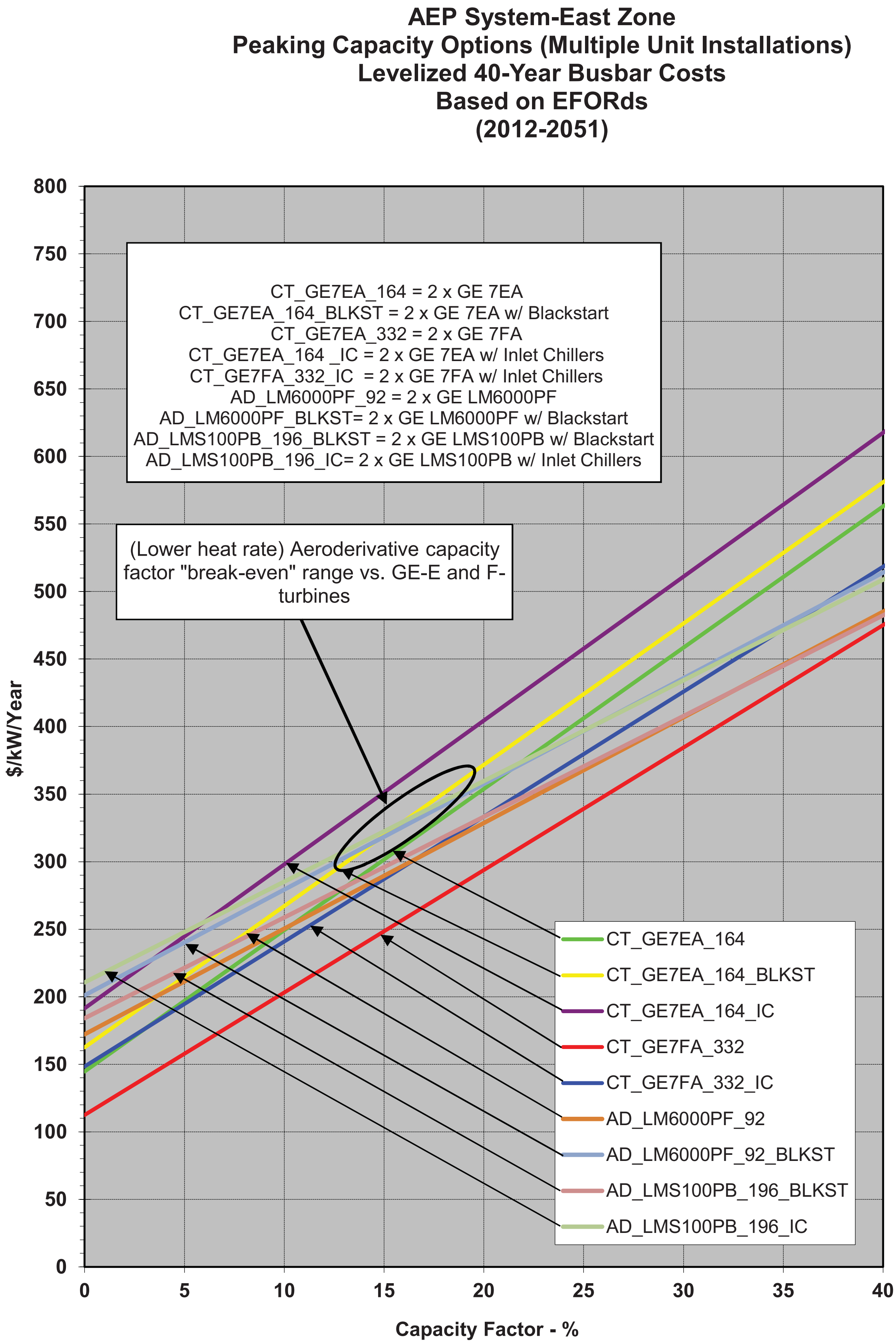
Note: Rockport is based on I&M's portion only (85% Unit 1 & 85% of Unit 2)

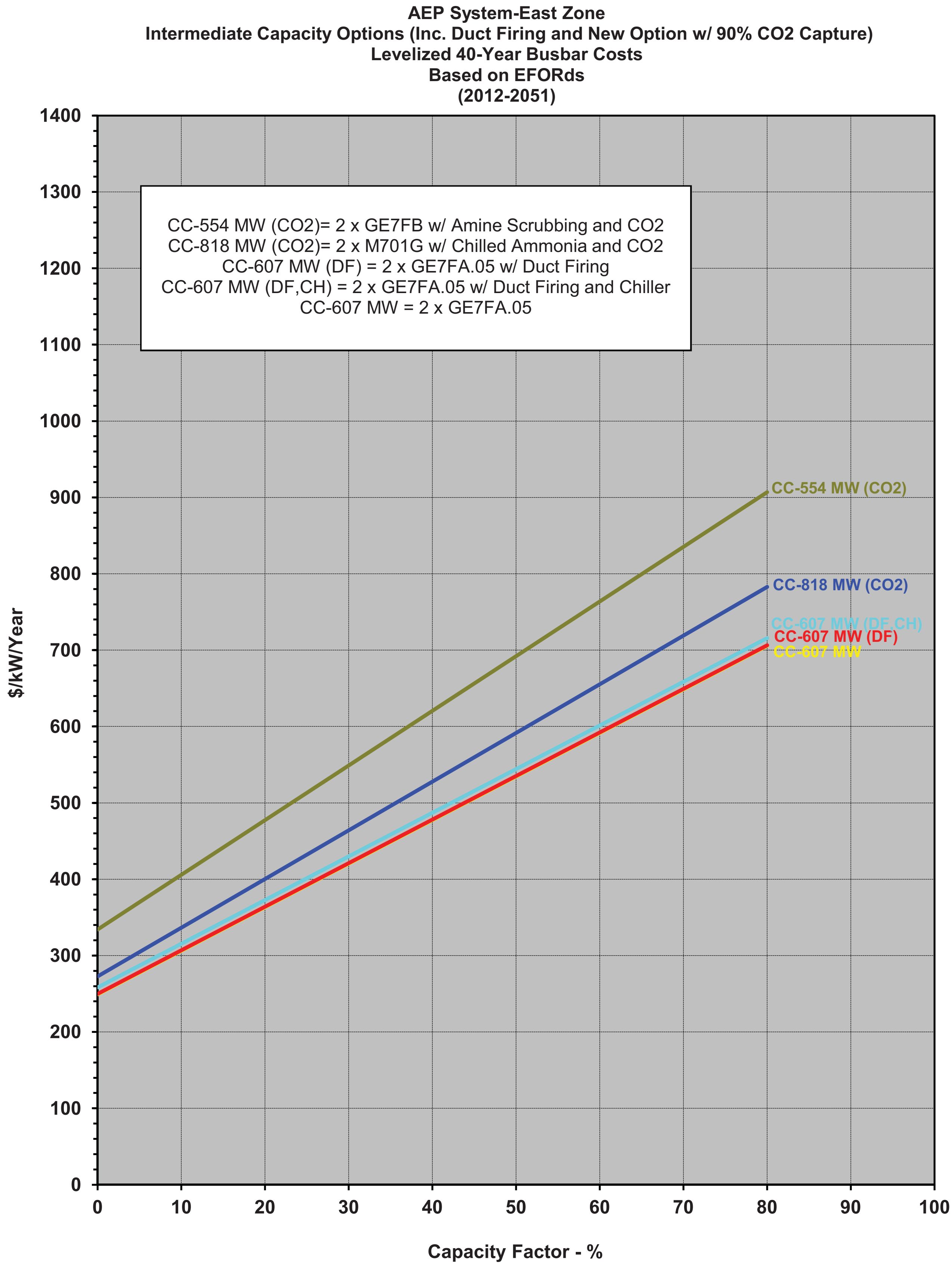
Note: No unit sales are reflected here

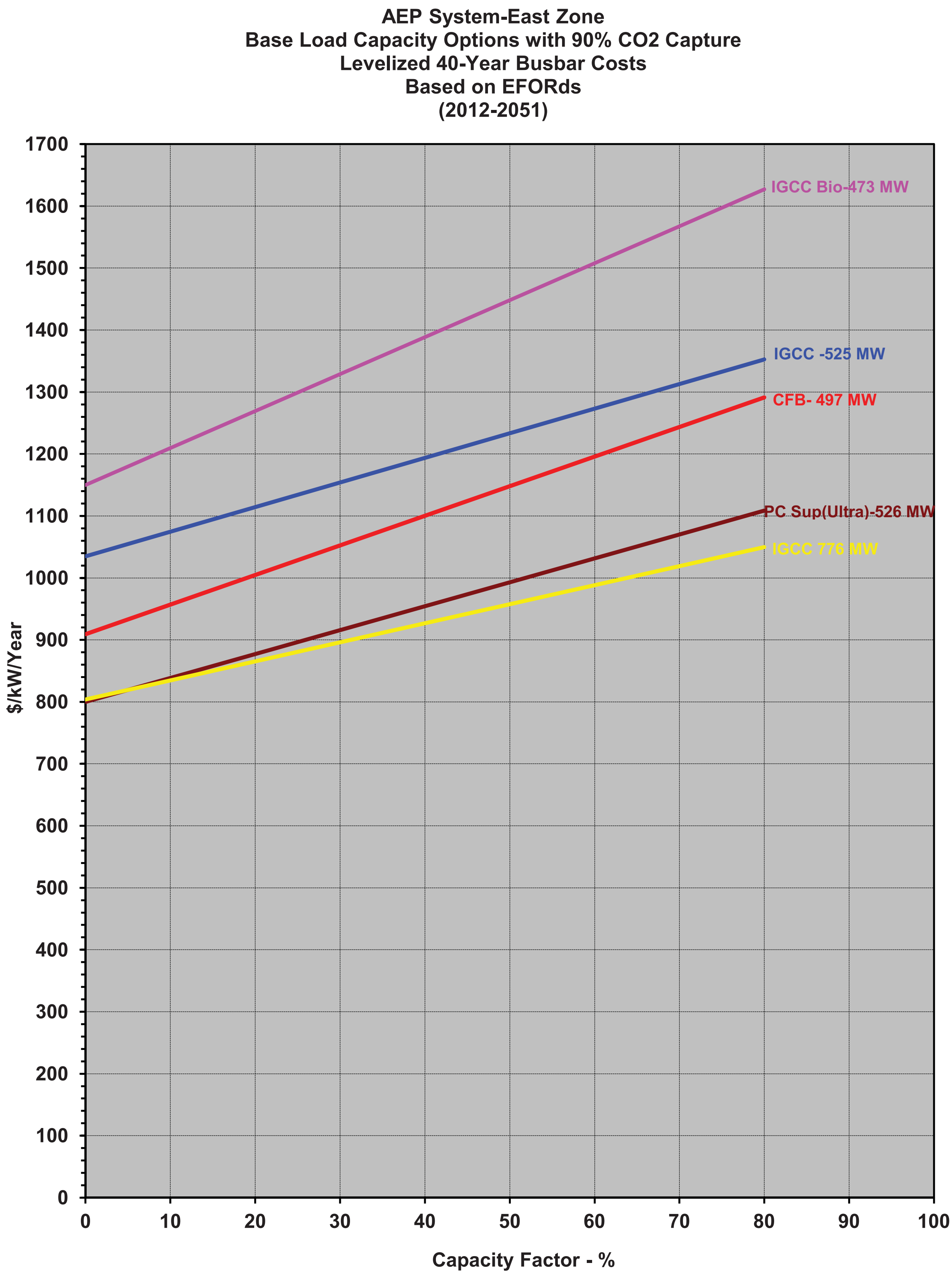

I&M
PJM Capacity (UCAP) Position
MW - Summer Capacity
5,500
5,000
4,500
4,000
3,500
3,000
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
2029
2030
2031
Remaining Existing Capacity (MW)
New Renewable Generation (MW)
Total Obligation (MW) (Excluding DR/EE/INT)
New Fossil Fuel Generation (MW)
Annual Purchases (MW)
Total Obligation (MW)

AEP-East
PJM Capacity (UCAP) Position

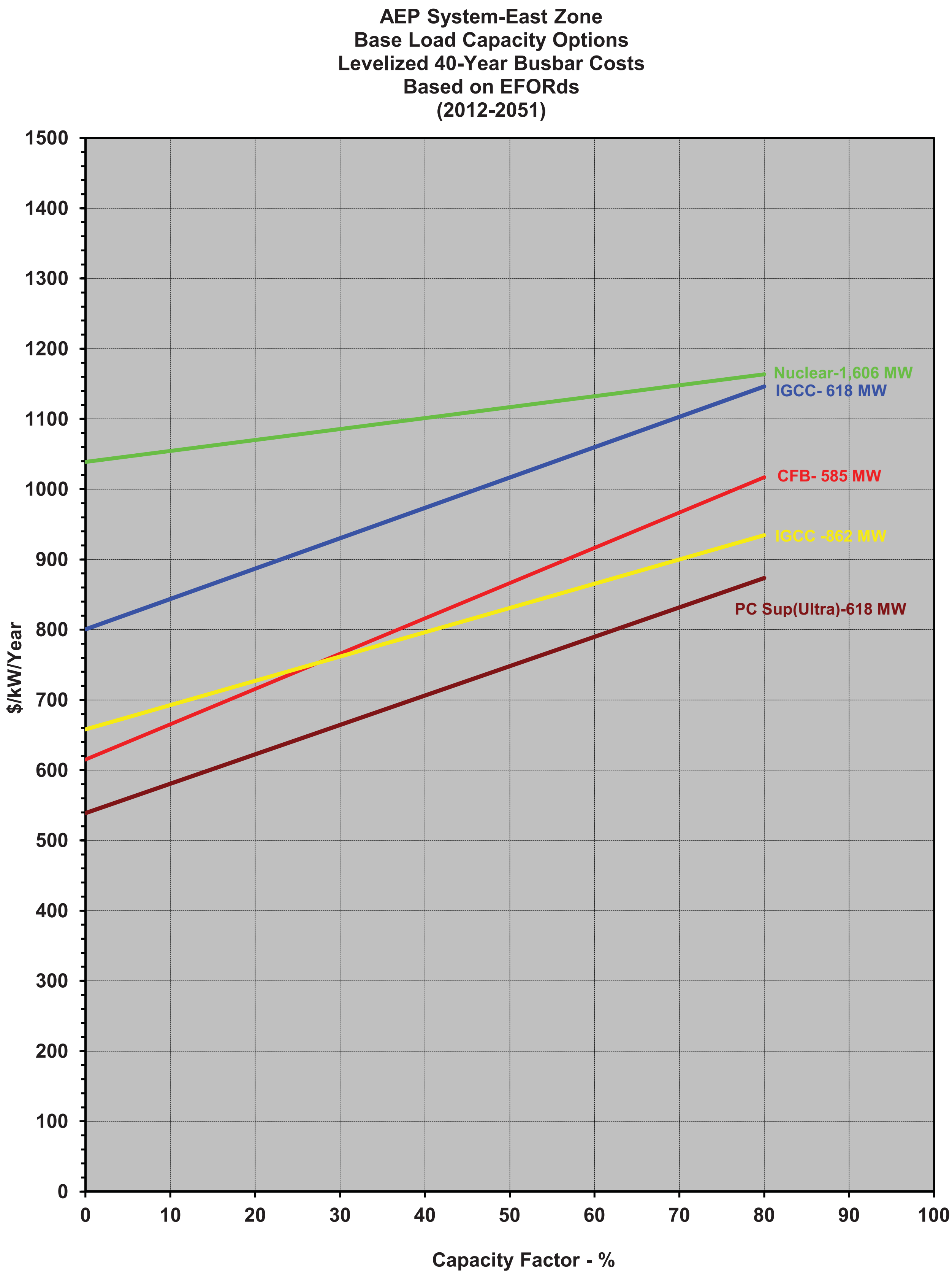


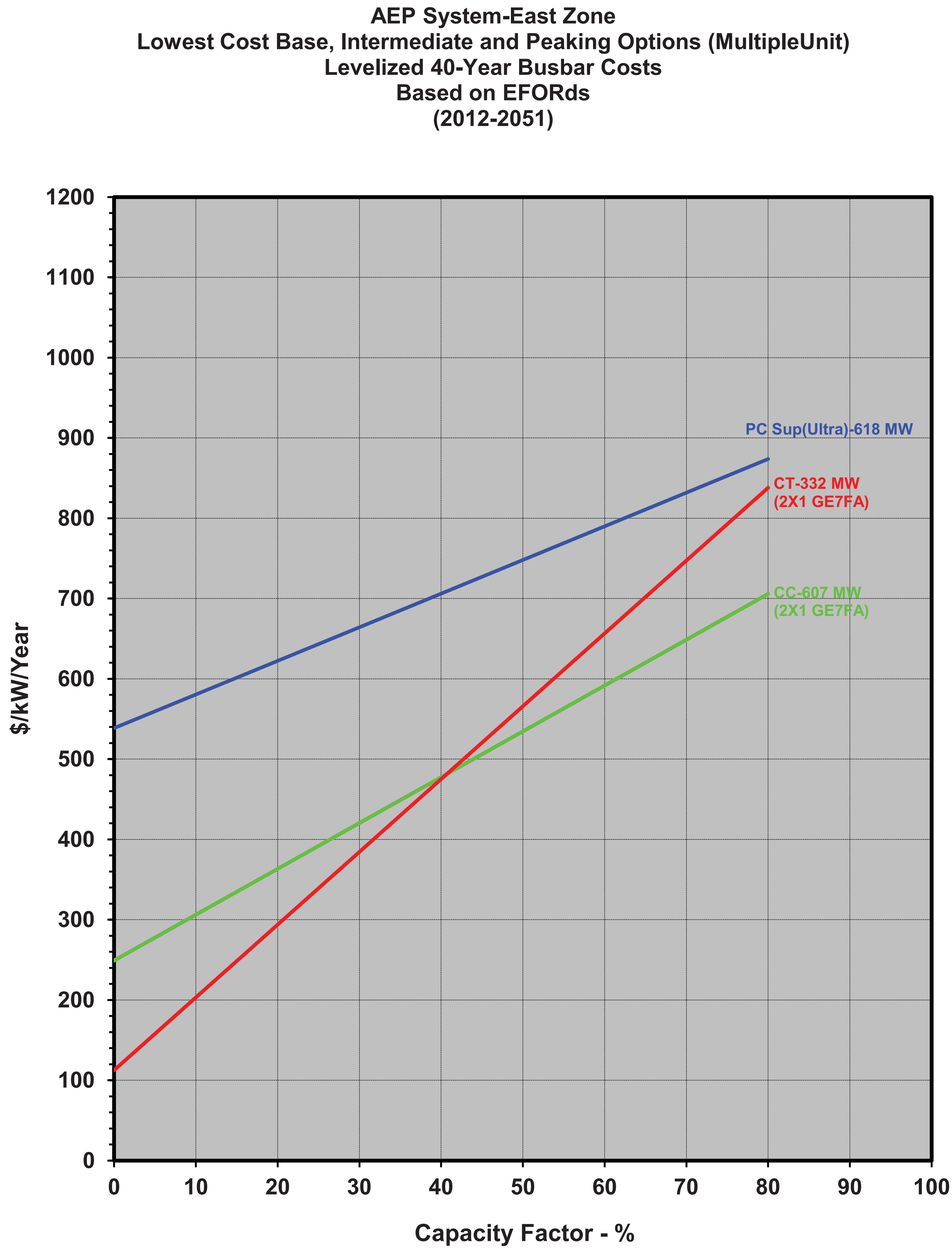

AEP System-East Zone
Peaking Capacity Options (Multiple Unit Installations)
Levelized 40-Year Busbar Costs
Based on EFORds
(2012-2051)
CT_GE7EA_164 = 2 x GE 7EA
CT_GE7EA_164_BLKST = 2 x GE 7EA w/ Blackstart
CT_GE7EA_332 = 2 x GE 7FA
CT_GE7EA_164 _IC = 2 x GE 7EA w/ Inlet Chillers
CT_GE7FA_332_IC = 2 x GE 7FA w/ Inlet Chillers
AD_LM6000PF_92 = 2 x GE LM6000PF
AD_LM6000PF_BLKST= 2 x GE LM6000PF w/ Blackstart
AD_LMS100PB_196_BLKST = 2 x GE LMS100PB w/ Blackstart
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
$/kW/Year
800
750
700
650
600
550
500
450
400
350
300
250
200
150
100
50
0
0
5
10
15
20
25
30
35
40
Capacity Factor - %
CT_GE7EA_164
CT_GE7EA_164_BLKST
CT_GE7EA_164_IC
CT_GE7FA_332
CT_GE7FA_332_IC
AD_LM6000PF_92
AD_LM6000PF_92_BLKST
AD_LMS100PB_196_BLKST
AD_LMS100PB_196_IC


AEP System-East Zone
Intermediate Capacity Options (Inc. Duct Firing and New Option w/ 90% CO2 Capture)
Levelized 40-Year Busbar Costs
Based on EFORds
(2012-2051)
CC-554 MW (CO2)= 2 x GE7FB w/ Amine Scrubbing and CO2
CC-818 MW (CO2)= 2 x M701G w/ Chilled Ammonia and CO2
CC-607 MW (DF) = 2 x GE7FA.05 w/ Duct Firing
CC-607 MW (DF,CH) = 2 x GE7FA.05 w/ Duct Firing and Chiller
CC-607 MW = 2 x GE7FA.05
CC-554 MW (CO2)
CC-818 MW (CO2)
CC-607 MW (DF,CH)
CC-607 MW (DF)
CC-607 MW
$/kW/Year
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
Capacity Factor - %



AEP System-East Zone
Base Load Capacity Options with 90% CO2 Capture
Levelized 40-Year Busbar Costs
Based on EFORds
(2012-2051)
$/kW/Year
Capacity Factor - %
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
1500
1600
1700
0
10
20
30
40
50
60
70
80
90
100
IGCC Bio-473 MW
IGCC -525 MW
CFB- 497 MW
PC Sup(Ultra)-526 MW
IGCC 776 MW


AEP System-East Zone
Base Load Capacity Options
Levelized 40-Year Busbar Costs
Based on EFORds
(2012-2051)
$/kW/Year
Capacity Factor - %
Nuclear-1,606 MW
IGCC- 618 MW
CFB- 585 MW
IGCC -862 MW
PC Sup(Ultra)-618 MW
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
1500
10
20
30
40
50
60
70
80
90
100


AEP System-East Zone
Lowest Cost Base, Intermediate and Peaking Options (MultipleUnit)
Levelized 40-Year Busbar Costs
Based on EFORds
(2012-2051)
$/kW/Year
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
Capacity Factor - %
0
10
20
30
40
50
60
70
80
90
100
PC Sup(Ultra)-618 MW
CT-332 MW
(2X1 GE7FA)
CC-607 MW
(2X1 GE7FA)

Forecasted Capacity Prices
2012-2030
Per Fundamental Analysis 1H-2011 Forecast
$/MW-Day (Nominal)

AEP GEN HUB (PJM RTO)

Year	Fleet Transition (FT Case)	Fleet Transition Carbon Adjusted (FTCA Case)	Low Band (L Case)
2012	$55.44	$55.44	$55.44
2013	$23.03	$23.03	$23.03
2014	$26.14	$26.14	$26.14
2015	$25.00	$25.00	$25.00
2016	$58.67	$52.56	$25.00
2017	$128.80	$126.00	$25.00
2018	$162.33	$159.61	$66.67
2019	$194.72	$192.27	$121.58
2020	$226.01	$224.01	$238.36
2021	$255.14	$253.29	$308.32
2022	$282.32	$280.43	$307.94
2023	$311.63	$306.72	$308.79
2024	$327.79	$322.74	$310.91
2025	$343.29	$345.90	$314.36
2026	$358.11	$357.93	$319.64
2027	$372.21	$368.96	$326.01
2028	$385.56	$378.93	$333.89
2029	$397.73	$387.42	$343.07
2030	$409.05	$394.76	$353.73

Forecasted Natural Gas Prices
2012-2030
Per Fundamental Analysis 1H-2011 Forecast
$/MMBtu (Nominal)

	TCO Pool			TCO Delivered		
Year	Fleet Transition (FT Case)	Fleet Transition Carbon Adjusted (FTCA Case)	Low Band (L Case)	Fleet Transition (FT Case)	Fleet Transition Carbon Adjusted (FTCA Case)	Low Band (L Case)
2012	$4.29	$4.31	$3.55	$4.59	$4.61	$3.84
2013	$4.77	$4.77	$3.93	$5.08	$5.09	$4.22
2014	$5.11	$5.11	$4.20	$5.42	$5.43	$4.50
2015	$5.21	$5.21	$4.28	$5.53	$5.53	$4.58
2016	$5.42	$5.42	$4.45	$5.75	$5.75	$4.75
2017	$5.57	$5.45	$4.48	$5.90	$5.78	$4.78
2018	$6.08	$5.69	$4.67	$6.42	$6.03	$4.98
2019	$6.30	$5.90	$4.85	$6.65	$6.24	$5.16
2020	$6.46	$6.07	$4.99	$6.81	$6.42	$5.30
2021	$6.69	$6.29	$5.17	$7.05	$6.64	$5.48
2022	$6.82	$6.55	$5.37	$7.18	$6.90	$5.70
2023	$7.00	$6.74	$5.53	$7.36	$7.09	$5.86
2024	$7.23	$6.96	$5.71	$7.60	$7.32	$6.04
2025	$7.44	$7.17	$5.88	$7.81	$7.53	$6.22
2026	$7.56	$7.26	$5.96	$7.93	$7.63	$6.30
2027	$7.72	$7.43	$6.10	$8.10	$7.80	$6.43
2028	$7.88	$7.59	$6.23	$8.26	$7.96	$6.57
2029	$8.07	$7.76	$6.37	$8.45	$8.14	$6.72
2030	$8.17	$7.87	$6.46	$8.56	$8.24	$6.80

Forecasted Energy Prices
2012-2030
Per Fundamental Analysis 1H-2011 Forecast
$/MWh (Nominal)

AEP GEN HUB (PJM RTO)

	Fleet Transition (FT Case)		Fleet Transition Carbon Adjusted (FTCA Case)		Low Band (L Case)	
Year	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
2012	$45.47	$27.57	$46.84	$27.42	$41.52	$25.09
2013	$49.56	$30.97	$50.04	$30.73	$44.95	$28.02
2014	$53.17	$32.76	$53.56	$32.93	$48.82	$30.01
2015	$54.11	$33.57	$54.92	$33.53	$49.31	$30.22
2016	$54.18	$32.67	$55.58	$32.63	$49.59	$29.25
2017	$67.17	$48.10	$57.29	$33.79	$50.54	$29.93
2018	$69.34	$49.84	$60.51	$36.08	$52.62	$31.15
2019	$71.01	$52.41	$61.93	$37.97	$53.58	$32.91
2020	$71.76	$54.41	$63.30	$39.89	$55.16	$35.29
2021	$72.16	$55.75	$64.04	$41.29	$55.87	$36.19
2022	$73.74	$57.00	$72.78	$51.50	$65.00	$46.65
2023	$75.01	$57.29	$74.37	$52.71	$67.12	$48.08
2024	$76.72	$58.79	$75.48	$53.94	$67.91	$48.89
2025	$77.18	$60.16	$77.35	$55.55	$68.47	$49.98
2026	$78.85	$61.41	$78.47	$56.66	$68.77	$50.37
2027	$79.43	$62.51	$79.73	$57.44	$71.18	$52.24
2028	$81.36	$63.65	$81.84	$59.20	$71.75	$52.78
2029	$82.43	$65.04	$82.13	$60.20	$73.03	$54.16
2030	$83.21	$65.77	$83.85	$61.62	$73.58	$54.88

Forecasted Coal Prices (FOB)
2012-2030
Per Fundamental Analysis 1H-2011 Forecast
$/Ton (Nominal)

	CAPP NYMEX			PRB 8800		
Year	Fleet Transition (FT Case)	Fleet Transition Carbon Adjusted (FTCA Case)	Low Band (L Case)	Fleet Transition (FT Case)	Fleet Transition Carbon Adjusted (FTCA Case)	Low Band (L Case)
2012	$79.00	$79.00	$68.25	$14.80	$14.80	$12.11
2013	$81.00	$81.00	$69.98	$15.55	$15.55	$12.72
2014	$79.00	$79.00	$68.25	$15.61	$15.61	$12.77
2015	$80.11	$80.11	$69.21	$15.95	$15.99	$13.08
2016	$81.22	$81.22	$70.17	$16.29	$16.37	$13.39
2017	$80.83	$82.77	$71.50	$16.60	$16.76	$13.71
2018	$80.83	$84.35	$72.87	$16.91	$17.16	$14.04
2019	$81.59	$85.94	$74.24	$17.23	$17.57	$14.38
2020	$82.34	$87.53	$75.62	$17.55	$17.99	$14.71
2021	$83.86	$89.32	$77.16	$17.88	$18.41	$15.06
2022	$85.41	$88.93	$76.82	$18.21	$18.47	$15.11
2023	$86.98	$90.73	$78.38	$18.54	$18.90	$15.46
2024	$88.56	$92.56	$79.96	$18.88	$19.34	$15.82
2025	$90.15	$94.41	$81.56	$19.22	$19.78	$16.18
2026	$91.75	$96.28	$83.18	$19.56	$20.24	$16.55
2027	$93.38	$98.18	$84.81	$19.90	$20.70	$16.93
2028	$95.02	$100.10	$86.48	$20.25	$21.16	$17.31
2029	$96.69	$102.06	$88.17	$20.61	$21.64	$17.70
2030	$98.37	$104.04	$89.88	$20.97	$22.13	$18.10

Forecasted CO_2 Prices
2012-2030
Per Fundamental Analysis 1H-2011 Forecast
$/Tonne (Nominal)

Year	Fleet Transition (FT Case)	Fleet Transition Carbon Adjusted (FTCA Case)	Low Band (L Case)
2012	$0.00	$0.00	$0.00
2013	$0.00	$0.00	$0.00
2014	$0.00	$0.00	$0.00
2015	$0.00	$0.00	$0.00
2016	$0.00	$0.00	$0.00
2017	$18.74	$0.00	$0.00
2018	$19.84	$0.00	$0.00
2019	$20.94	$0.00	$0.00
2020	$22.05	$0.00	$0.00
2021	$22.33	$0.00	$0.00
2022	$22.62	$15.08	$15.08
2023	$22.92	$15.28	$15.28
2024	$23.21	$15.48	$15.48
2025	$23.51	$15.67	$15.67
2026	$23.82	$15.88	$15.88
2027	$24.13	$16.08	$16.08
2028	$24.45	$16.29	$16.29
2029	$24.77	$16.50	$16.50
2030	$25.07	$16.72	$16.72

I&M Under Various Commodity Pricing (Feb Load Forecast)
Capacity Resource Optimization
Expansion Plan Summary

	"Base" Plan	"Gas" Plan	"Market" Plan
2011-2014			
2015			201 MW - ICAP
2016			135 MW - ICAP
2017		1- 618 MW CC	103 MW - ICAP
2018			88 MW - ICAP
2019			78 MW - ICAP
2020			35 MW - ICAP
2021			50 MW - ICAP
2022			57 MW - ICAP
2023			70 MW - ICAP
2024	1- 618 MW CC		1- 618 MW CC
2025			
2026			
2027			
2028			
2029			
2030			
2031			
2032			
2033			
2034			
2035	2- 618 MW CC	2- 618 MW CC	2- 618 MW CC
2036			
2037	2- 618 MW CC	2- 618 MW CC	2- 618 MW CC
2038	1- 618 MW CC	1- 618 MW CC	1- 618 MW CC
2039			
2040			
Fleet Transition			
2011-2040 CPW ($000)	**$17,198,538**	**$17,363,153**	**$17,263,653**
Fleet Transition Carbon Adjusted			
2011-2040 CPW ($000)	**$16,614,321**	**$16,815,432**	**$16,713,730**
Low Band			
2011-2040 CPW ($000)	**$17,238,172**	**$17,374,907**	**$17,292,470**

AEP-East Under Various Commodity Pricing (Feb Load Forecast)
Capacity Resource Optimization
Expansion Plan Summary

	Fleet Transition Pricing		**Fleet Transition - Carbon Adjusted Pricing**		**Low Band Pricing**	
	Market Plan Optimization ICAP Purchases (MW)	**Build Plan** Optimization ICAP and New Unit Additions	**Market Plan** Optimization ICAP Purchases (MW)	**Build Plan** Optimization ICAP and New Unit Additions	**Market Plan** Optimization ICAP Purchases (MW)	**Build Plan** Optimization ICAP and New Unit Additions
2011 -2013						
2014	1,776	1,776 MW ICAP	1,776	1,776 MW ICAP	1,776	1,776 MW ICAP
2015	1,643	1,563 MW ICAP	1,563	1,563 MW ICAP	1,563	1,563 MW ICAP
2016	843	843 MW ICAP	843	843 MW ICAP	843	843 MW ICAP
2017	757	2-618 MW CCs	757	1-618 MW CC, 7-86 MW CTs	757	2-618 MW CCs
2018	823		823		823	
2019	888		888		888	
2020	885		885		885	
2021	1,052		1,052		1,052	
2022	1,158	7-86 MW CTs	1,158	1-618 MW CC	1,158	1-618 MW CC
2023	1,230		1,230		1,230	
2024	1,718	1-618 MW CC	1,718	1-618 MW CC	1,718	1-618 MW CC
2025	3-618 MW CCs, 7-86 MW CTs		3-618 MW CCs, 7-86 MW CTs		4-618 MW CCs	
2026						
2027	7-86 MW CTs	7-86 MW CTs	7-86 MW CTs	7-86 MW CTs	1-618 MW CC	1-618 MW CC
2028						
2029	7-86 MW CTs	7-86 MW CTs	7-86 MW CTs	7-86 MW CTs	7-86 MW CTs	7-86 MW CTs
2030						
2031	1-618 MW CC	1-618 MW CC	1-618 MW CC	1-618 MW CC	7-86 MW CTs	7-86 MW CTs
2032						
2033						
2034	7-86 MW CTs	1-618 MW CC	1-618 MW CC	1-618 MW CC	1-618 MW CC	1-618 MW CC
2035	2-618 MW CCs	2-618 MW CCs	2-618 MW CCs	2-618 MW CCs	2-618 MW CCs	2-618 MW CCs
2036						
2037	2-618 MW CCs, 7-86 MW CTs	2-618 MW CCs, 7-86 MW CTs	2-618 MW CCs, 7-86 MW CTs	2-618 MW CCs, 7-86 MW CTs	2-618 MW CCs, 7-86 MW CTs	2-618 MW CCs, 7-86 MW CTs
2038						
2039	1-618 MW CC	1-618 MW CC	1-618 MW CC	1-618 MW CC	1-618 MW CC	1-618 MW CC
2040						
2011-2040 CPW ($000)	**85,209,474**	**85,445,026**	**78,636,155**	**78,881,519**	**84,701,834**	**84,923,870**

I&M Capacity Portfolio (Stand-Alone View)

Planning Year	Existing Capacity (MW) (a)		New Capacity (MW)			DR/EE/INT (MW) (c)(d)		Market Purchases (MW)
	Retirements	Rating Adjustments	Renewable (Nameplate)	Renewable (b)	Fossil Fuel	DR/EE	Contracted Interruptible	
2011 /12						14	258	
2012 /13						23	258	
2013 /14			100	13		49	258	
2014 /15	(485)		100	13		123	258	0
2015 /16			100	13		186	258	0
2016 /17						249	258	0
2017 /18						313	258	0
2018 /19						353	258	0
2019 /20						389	258	0
2020 /21		30	100	13		408	258	0
2021 /22						412	258	0
2022 /23						415	258	0
2023 /24						418	258	0
2024 /25	(500)				562	419	258	0
2025 /26						423	258	0
2026 /27						423	258	0
2027 /28			100	13		423	258	0
2028 /29						422	258	0
2029 /30						423	258	0
2030 /31						423	258	0
2031 /32						423	258	0
	(985)	**30**	**500**	**65**	**562**	**423**	**258**	

(a) Not shown are smaller unit derates and uprates (<10MW) which are embedded in the current plan and are largely offsetting. Retirements are shown in the calendar year in which they occur.
(b) Capacity value in PJM is initially set at 13% of nameplate for wind and 38% of nameplate for solar
(c) Energy Efficiency (EE) represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast
(d) Demand Response (DR) represents demand response curtailment programs and tariffs

AEP-East Capacity Portfolio

Planning Year	Existing Capacity (MW) (a)		New Capacity (MW)			DR/EE/INT (MW) (c)(d)		Market Purchases (MW)
	Retirements	Rating Adjustments	Renewable (Nameplate)	Renewable (b)	Fossil Fuel	DR/EE	Contracted Interruptible	
2011 /12		(10)				123	519	0
2012 /13	(560)		117	20	580	199	519	0
2013 /14			120	21		302	519	0
2014 /15	(3,747)	(136)	232	38		570	519	1,776
2015 /16	(278)		215	32		823	519	1,643
2016 /17			150	20	602	1,100	519	843
2017 /18			150	20		1,365	519	757
2018 /19			117	20		1,478	519	823
2019 /20			100	13		1,617	519	888
2020 /21		35	271	40		1,765	519	885
2021 /22			100	13		1,870	519	1,052
2022 /23			100	13		1,955	519	1,158
2023 /24			200	26		2,026	519	1,230
2024 /25	(500)		21	8		2,080	519	1,718
2025 /26					2,236	2,130	519	0
2026 /27						2,142	519	0
2027 /28			100	13	550	2,142	519	0
2028 /29			50	7		2,140	519	0
2029 /30					550	2,142	519	0
2030 /31						2,142	519	0
2031 /32					562	2,142	519	0
	(5,085)	**(111)**	**2,043**	**301**	**5,080**	**2,142**	**519**	

(a) Not shown are smaller unit derates and uprates (<10MW) which are embedded in the current plan and are largely offsetting. Retirements are shown in the calendar year in which they occur.
(b) Capacity value in PJM is initially set at 13% of nameplate for wind and 38% of nameplate for solar
(c) Energy Efficiency (EE) represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast
(d) Demand Response (DR) represents demand response curtailment programs and tariffs

INDIANA MICHIGAN POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on (March 2011) Load Forecast
(2011/2012 - 2031/2032)
2011 I&M IRP

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)
					=(1)+(3)				=((4)-((5)*(6)))*(7)		=(8)+(9)						=(11)-(12) + Sum(14) +(15)		=(16)*(1-(17))	=((11)-(12) +(15)) *(1-(17)) -(10)	=(18)-(10)
		Obligation to PJM										Resources								I&M Position (MW)	
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
2011 /12	(k)	4,268	(9)	0	4,268	244	0.955	1.083	4,371	0	4,371	5,502	290				5,212	15.23%	4,418	47	47
2012 /13	(k)	4,389	(17)	0	4,389	246	0.950	1.080	4,487	0	4,487	5,500	161				5,339	6.39%	4,998	511	511
2013 /14	(k)	4,496	(43)	0	4,496	246	0.957	1.080	4,603	0	4,603	5,500	116	100 MW Wind	13	0	5,397	6.47%	5,048	433	445
2014 /15	(k)	4,552	(90)	(9)	4,544	273	0.956	1.081	4,629	0	4,629	5,015	(66)	100 MW Wind	13	0	5,107	6.00%	4,801	147	172
2015 /16		4,486	(131)	(17)	4,468	295	0.956	1.081	4,526	0	4,526	5,003	(93)	100 MW Wind	13	0	5,135	5.92%	4,831	268	305
2016 /17		4,499	(166)	(43)	4,456	322	0.956	1.081	4,483	0	4,483	5,012	(102)				5,153	5.92%	4,848	328	365
2017 /18		4,536	(203)	(90)	4,446	350	0.956	1.081	4,445	0	4,445	5,012	(95)				5,146	5.92%	4,841	360	396
2018 /19		4,562	(241)	(131)	4,431	352	0.956	1.081	4,426	0	4,426	5,012	(91)				5,142	5.92%	4,838	375	412
2019 /20		4,590	(275)	(166)	4,424	354	0.956	1.081	4,416	0	4,416	5,012	(90)				5,141	5.92%	4,837	384	421
2020 /21		4,596	(291)	(203)	4,393	356	0.956	1.081	4,380	0	4,380	5,041	(68)	100 MW Wind	13	0	5,161	5.91%	4,856	427	476
2021 /22		4,624	(293)	(241)	4,383	359	0.956	1.081	4,367	0	4,367	5,041	(39)				5,132	5.91%	4,829	413	462
2022 /23		4,642	(294)	(275)	4,367	361	0.956	1.081	4,347	0	4,347	5,041	(11)				5,104	5.91%	4,802	406	455
2023 /24		4,665	(294)	(291)	4,374	364	0.956	1.081	4,352	0	4,352	5,041	(3)				5,096	5.91%	4,795	394	443
2024 /25		4,686	(293)	(293)	4,394	366	0.956	1.081	4,371	0	4,371	4,541	(2)	562 MW CC	562	0	5,157	5.04%	4,897	(57)	526
2025 /26		4,733	(294)	(294)	4,440	369	0.956	1.081	4,418	0	4,418	4,541	(1)				5,156	5.04%	4,896	(105)	478
2026 /27		4,768	(294)	(294)	4,474	369	0.956	1.081	4,456	0	4,456	4,541	(1)				5,156	5.04%	4,896	(143)	440
2027 /28		4,803	(294)	(293)	4,509	369	0.956	1.081	4,494	0	4,494	4,541	(1)	100 MW Wind	13	0	5,169	5.02%	4,910	(180)	416
2028 /29		4,831	(293)	(294)	4,537	369	0.956	1.081	4,523	0	4,523	4,541	(1)				5,169	5.02%	4,910	(209)	387
2029 /30		4,877	(294)	(294)	4,583	369	0.956	1.081	4,573	0	4,573	4,541	(1)				5,169	5.02%	4,910	(259)	337
2030 /31		4,917	(294)	(294)	4,623	369	0.956	1.081	4,617	0	4,617	4,541	(1)				5,169	5.02%	4,910	(303)	293
2031 /32		4,958	(294)	(293)	4,665	369	0.956	1.081	4,661	0	4,661	4,541	(1)				5,169	5.02%	4,910	(347)	249

Notes:

(a) Based on (March 2011) Load Forecast (with implied PJM diversity factor)
Includes company MLR share of NCEMC

(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' ~3 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) = 15.5%(2010-2011), 15.4%(2012), 15.3%(2013-2030)
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 (7.95% PPR-share of full ~2,180 total capacity)
Assumes hydro units are derated to August average output in 2015/16
Wind Farm PPAs (Where Applicable)

(g) continued
EFFICIENCY IMPROVEMENTS:
2011/12: Cook 2: 14 MW (Uprate)
2015/16: Rockport 1: 35 MW (valve) (offset to FGD derate)
2019/20: Rockport 2: 35 MW (valve)
FGD DERATES:
2011/12: Kyger Creek 1-5: 3 MW each
2012/13: Clifty Creek 1-6: 2 MW each
2015/16: Rockport 1: 35 MW
DSI DERATES:
2013/14: Rockport 2: 0 MW; Tanners Ck. 4 0 MW
SCR DERATES:
2015/16: Rockport 1: 0 MW
RETIREMENTS:
2014/15: Tanners Ck. 1-3
2024/25: Tanners Ck. 4

(h) Includes company MLR share of:
Constellation purchase of 315 MW in 2010/11-2011/12
Sale of 22 MW from Tanners Ck. 4 in 2011/12 and 30 MW in 2012/13
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA
2010/11-2012/13 (45 MW, 387 MW, 160 MW)
RPM Auction Sales 2010/11 - 2013/14 (1458, 1414, 696
, 761)(MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

Plus: Estimated I&M nominations for PJM EE ('passive' DR program) levels
--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

AEP SYSTEM - EASTERN ZONE
Projected Summer Peak Demands, Generating Capabilities, and Margins (UCAP)
Based on (March 2011) Load Forecast
(2011/2012 - 2031/2032)
2011 I&M IRP

Planning Year	(1) Internal Demand (a)	(2) DSM (b)	(3) Projected DSM Impact (c)	(4) Net Internal Demand	(5) Interruptible Demand Response (d)	(6) Demand Response Factor	(7) Forecast Pool Req't (e)	(8) UCAP Obligation	(9) Net UCAP Market Obligation (f)	(10) Total UCAP Obligation	(11) Existing Capacity & Planned Changes (g)	(12) Net Capacity Sales (h)	(13) Planned Capacity Additions Units	(14) MW (i)	(15) Annual Purchases	(16) Net ICAP	(17) AEP EFORd (j)	(18) Available UCAP	(19) Net Position w/o New Capacity	(20) Net Position w/ New Capacity
	Obligation to PJM										Resources								AEP Position (MW)	
				=(1)+(3)				=((4)-((5)*(6)))*(7)		=(8)+(9)						=(11)-(12) + Sum(14) +(15)		=(16)*(1-(17))	=((11)-(12) +(15)) *(1-(17)) -(10)	=(18)-(10)
2011 /12 (k)	20,515	(76)	(1)	20,514	492	0.955	1.083	21,713	1,396	23,109	28,312	1,505				26,807	9.83%	24,172	1,063	1,063
2012 /13 (k)	21,098	(149)	(1)	21,097	495	0.950	1.080	22,271	1,396	23,667	27,740	776	580 MW D CC & 17 MW Solar & 100 MW Wind	600	0	27,564	8.61%	25,191	975	1,524
2013 /14 (k)	21,610	(252)	(1)	21,609	495	0.957	1.080	22,833	1,396	24,229	27,740	567	20 MW Solar & 100 MW Wind	21	0	27,793	8.52%	25,425	629	1,196
2014 /15 (k)	21,882	(390)	(76)	21,806	625	0.956	1.081	22,924	1,396	24,320	23,857	(242)	32 MW Solar & 200 MW Wind & 1776 MW ICAP	38	1,776	26,533	7.46%	24,554	(375)	234
2015 /16	21,709	(523)	(149)	21,561	745	0.956	1.081	22,536	1,396	23,932	23,303	(315)	15 MW Solar & 200 MW Wind & 1643 MW ICAP	32	1,643	25,951	7.37%	24,038	(533)	106
2016 /17	21,827	(650)	(252)	21,576	895	0.956	1.081	22,397	1,396	23,793	23,313	(335)	602 MW BS1RP & 150 MW Wind & 843 MW ICAP	622	843	25,803	7.38%	23,899	(1,109)	106
2017 /18	22,013	(765)	(390)	21,623	1,045	0.956	1.081	22,293	1,396	23,689	23,313	(316)	150 MW Wind & 757 MW ICAP	20	757	25,717	7.37%	23,822	(1,100)	133
2018 /19	22,194	(866)	(523)	21,672	1,057	0.956	1.081	22,333	1,396	23,729	23,313	(289)	17 MW Solar & 100 MW Wind & 823 MW ICAP	20	823	25,776	7.37%	23,876	(1,104)	147
2019 /20	22,396	(993)	(650)	21,746	1,070	0.956	1.081	22,400	1,396	23,796	23,313	(290)	100 MW Wind & 888 MW ICAP	13	888	25,855	7.36%	23,952	(1,108)	156
2020 /21	22,560	(1,128)	(765)	21,795	1,082	0.956	1.081	22,440	1,396	23,836	23,348	(303)	21 MW Solar & 250 MW Wind & 885 MW ICAP	40	885	25,940	7.35%	24,033	(1,103)	197
2021 /22	22,823	(1,221)	(866)	21,957	1,095	0.956	1.081	22,603	1,396	23,999	23,348	(298)	100 MW Wind & 1052 MW ICAP	13	1,052	26,115	7.35%	24,196	(1,116)	197
2022 /23	23,022	(1,293)	(993)	22,029	1,108	0.956	1.081	22,668	1,396	24,064	23,348	(253)	100 MW Wind & 1158 MW ICAP	13	1,158	26,189	7.34%	24,267	(1,122)	203
2023 /24	23,186	(1,350)	(1,128)	22,058	1,121	0.956	1.081	22,685	1,396	24,081	23,348	(193)	200 MW Wind & 1230 MW ICAP	26	1,230	26,227	7.34%	24,302	(1,128)	221
2024 /25	23,324	(1,391)	(1,221)	22,104	1,134	0.956	1.081	22,720	1,396	24,116	22,848	(149)	21 MW Solar & 1718 MW ICAP	8	1,718	26,179	7.15%	24,307	(1,168)	191
2025 /26	23,573	(1,427)	(1,293)	22,280	1,148	0.956	1.081	22,896	1,396	24,292	22,848	(119)	1686 MW CC & 550 MW CT	2,236	0	26,666	7.20%	24,746	(2,979)	454
2026 /27	23,763	(1,439)	(1,350)	22,413	1,148	0.956	1.081	23,041	1,396	24,437	22,848	(80)				26,627	7.20%	24,710	(3,160)	273
2027 /28	23,963	(1,439)	(1,391)	22,572	1,148	0.956	1.081	23,213	1,396	24,609	22,848	(45)	550 MW CT & 100 MW Wind	563	0	27,155	7.21%	25,197	(3,367)	588
2028 /29	24,129	(1,437)	(1,427)	22,702	1,148	0.956	1.081	23,352	1,396	24,748	22,848	(13)	50 MW Wind	7	0	27,129	7.21%	25,173	(3,535)	425
2029 /30	24,354	(1,439)	(1,439)	22,915	1,148	0.956	1.081	23,583	1,396	24,979	22,848	(4)	550 MW CT	550	0	27,670	7.23%	25,669	(3,779)	690
2030 /31	24,573	(1,439)	(1,439)	23,134	1,148	0.956	1.081	23,819	1,396	25,215	22,848	(4)				27,670	7.23%	25,669	(4,015)	454
2031 /32	24,798	(1,439)	(1,437)	23,361	1,148	0.956	1.081	24,066	1,396	25,462	22,848	(4)	562 MW CC	562	0	28,232	7.24%	26,188	(4,264)	726

Notes: (a) Based on (March 2011) Load Forecast (with implied PJM diversity factor)
Includes Monongahela Power & NCEMC

(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' ~3 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) = 15.5%(2010-2011), 15.4%(2012), 15.3%(2013-2030)
Forecast Pool Requirement (FPR) = (1 + IRM) * (1 - PJM EFORd)

(f) Includes:
FRR view of obligations only
Buckeye Cardinal and Mone obligations

(g) Reflects the following summer capability assumptions:
AEP share of OVEC capacity (7.95% PPR-share of full ~2,180 total capacity)
Assumes hydro units, including Summersville, are derated to August average output in 2015/16
Wind Farm PPAs
EFFICIENCY IMPROVEMENTS:
2010/11: Amos 1: 12 MW (turbine)
2011/12: Cook 2: 14 MW (Uprate); Gavin 2: 0 MW (turbine)
2015/16: Rockport 1: 35 MW (valve) (offset to FGD derate)
2019/20: Rockport 2: 35 MW (valve)

(g) continued
CCS DERATES:
2011/12: Mountaineer 1: -6 MW (CCS Program Terminated)
FGD DERATES:
2010/11: Amos 1: 22 MW
2011/12: Cardinal 3: 10 MW; Kyger Creek 1-5: 3 MW each
2012/13: Clifty Creek 1-6: 2 MW each
2015/16: Rockport 1: 35 MW
DSI DERATES:
2013/14: Rockport 2: 0 MW; Tanners Ck. 4 0 MW
2015/16: Conesville 5: 0 MW; Conesville 6: 0 MW
SCR DERATES:
2015/16: Conesville 5: 4 MW; Conesville 6: 4 MW; Rockport 1: 0 MW
GAS CONVERSION DERATES:
2014/15: Clinch R. 1-2: 10% each; Muskingum River 5: 15%
RETIREMENTS:
2010/11: Sporn 5
2012/13: Conesville 3; Muskingum River 2,4
2014/15: Beckjord 6; Big Sandy 2; Clinch R. 3; Glen Lyn 5-6
2014/15: Kammer 1-3; Kanawha R. 1-2; Muskingum River 1,3
2014/15: Picway 5; Sporn 1-4; Tanners Ck. 1-3
2015/16: Big Sandy 1
2024/25: Tanners Ck. 4

(h) Includes:
Constellation purchase of 315 MW in 2010/11-2011/12
Sale of 22 MW from Tanners Ck. 4 in 2011/12 and 30 MW in 2012/13
Ceredo/Darby/Glen Lyn Sale to AMPO,ATSI, and IMEA
2010/11-2012/13 (45 MW, 387 MW, 160 MW)
RPM Auction Sales 2010/11 - 2013/14 (1458, 1414, 696
, 761)(MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

Plus: Estimated I&M nominations for PJM EE ('passive' DR program) levels
--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

INDIANA MICHIGAN POWER COMPANY
INTEGRATED RESOURCE PLAN
FINANCIAL INFORMATION
($ Millions)

Year	Nominal Value of Revenue Requirements	Discount Rate	Present Value of Revenue Requirements	Real Value of Revenue Requirements	Average Rate (Cents/kWh)
2011	1310	11.80%	1310	1310	5.61
2012	1417	11.80%	1267	1390	5.79
2013	1523	11.80%	1218	1466	5.51
2014	1533	11.80%	1097	1449	5.47
2015	1579	11.80%	1011	1464	5.55
2016	1750	11.80%	1002	1591	6.06
2017	1781	11.80%	912	1590	6.08
2018	1818	11.80%	833	1592	6.12
2019	1841	11.80%	754	1582	6.10
2020	1901	11.80%	697	1603	6.19
2021	1949	11.80%	639	1612	6.21

Notes:

(1) Present values are calculated using a mid-year convention along with I&M's discount rate (shown above).

(2) Real dollar values are calculated using an inflation rate of 1.91%. This rate is estimated to be an average for all customers.

(3) Discount Rate based on incremental pretax weighted average cost of capital per Finance Dept.

(4) Average rate calculated by dividing Real Value of Revenue Requirements by Internal GWh Sales.

(5) Data is only available through 2021.

Forecasted Capacity Prices
2011-2030
Per Fundamental Analysis 1H-2011 Forecast
$/MW-Day (Nominal)

AEP GEN HUB (PJM RTO)

Year	Fleet Transition Carbon Adjusted (FTCA Case)
2012	$55.44
2013	$23.03
2014	$26.14
2015	$25.00
2016	$52.56
2017	$126.00
2018	$159.61
2019	$192.27
2020	$224.01
2021	$253.29
2022	$280.43
2023	$306.72
2024	$322.74
2025	$345.90
2026	$357.93
2027	$368.96
2028	$378.93
2029	$387.42
2030	$394.76

I&M
ESTIMATED "AVOIDED COSTS" OF ENERGY
FOR ASSUMED LEVELS OF COGENERATION PURCHASES
2012 - 2021
(Cents Per Kilowatt-Hour)

ASSUMED COGENERATION PURCHASE LEVEL
100-MW Block

	Peak	Off-Peak
2012	3.42	2.92
2013	3.29	2.91
2014	4.40	3.71
2015	4.46	3.46
2016	3.94	3.15
2017	3.85	3.10
2018	4.00	3.21
2019	4.16	3.35
2020	4.23	3.43
2021	4.34	3.53

Notes:
A. Seasonal differences in energy costs are not sufficiently significant and/or consistent to warrant establishment of separate seasonal costing periods
B. The peak costing period is 0700 to 2100 local time Monday through Friday. All other hours comprise the off-peak costing period.
C. Energy costs are expressed in current-year dollars.

12) APPENDIX

Indiana Michigan Power Company

Model Equations

Results of Statistical Tests and Input Data Sets

Pertaining to the 2011 Load Forecast

(PROVIDED ON CD)

INDIANA MICHIGAN POWER COMPANY

HOURLY INTERNAL LOADS

2010

(PROVIDED ON CD)

AEP SYSTEM / INDIANA MICHIAN POWER COMPANY

HOURLY FIRM-LOAD LAMDAS

2010

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

Plant Name	Unit Number	City or County	State	In-Service Year	Unit Type	Primary Fuel	Secondary Fuel (if any)	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 6-1-2011
Cook Nuclear	2	Bridgman	MI	1978	ST	Nuclear	#N/A	100%	1,121	1,071	CL	As of 6-1-2011
Rockport	1	Rockport	IN	1984	ST	Coal	#N/A	85%	1,122	1,118	EP, LNB, OFA	As of 6-1-2011
Rockport	2	Rockport	IN	1989	ST	Coal	#N/A	85%	1,105	1,105	EP, LNB, OFA	As of 6-1-2011
Tanners Creek	1	Lawrenceburg	IN	1951	ST	Coal	#N/A	100%	145	145	EP, LNB	As of 6-1-2011
Tanners Creek	2	Lawrenceburg	IN	1952	ST	Coal	#N/A	100%	145	145	EP, LNB	As of 6-1-2011
Tanners Creek	3	Lawrenceburg	IN	1954	ST	Coal	#N/A	100%	205	195	EP, LNB	As of 6-1-2011
Tanners Creek	4	Lawrenceburg	IN	1964	ST	Coal	#N/A	100%	500	500	EP, OFA	As of 6-1-2011
Berrien Springs	1-12	Berrien Springs	MI	1908	HY	Water	#N/A	100%	5.2	3.1	#N/A	As of 6-1-2011
Buchanan	1-10	Buchanan	MI	1919	HY	Water	#N/A	100%	2.4	2.3	#N/A	As of 6-1-2011
Constantine	1-4	Constantine	MI	1921	HY	Water	#N/A	100%	0.8	0.5	#N/A	As of 6-1-2011
Elkhart	1-3	Elkhart	IN	1913	HY	Water	#N/A	100%	2.1	1.6	#N/A	As of 6-1-2011
Mottville	1-4	White Pigeon	MI	1923	HY	Water	#N/A	100%	0.9	0.6	#N/A	As of 6-1-2011
Twin Branch	1-8	Mishawaka	IN	1904	HY	Water	#N/A	100%	3.6	2.9	#N/A	As of 6-1-2011

* Denotes Expected Seasonal Generation Capability

Indiana Michigan Power Company

Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor

2001-2031

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
2001	08/08/01	4,232	---	12/31/00	3,393	---	4,232	---	22,284	---	60.1
2002	07/22/02	4,303	1.7	03/04/02	3,258	-4.0	4,303	1.7	23,293	4.5	61.8
2003	08/21/03	4,223	-1.9	01/07/03	3,683	13.0	4,223	-1.9	22,876	-1.8	61.8
2004	07/22/04	4,016	-4.9	01/22/04	3,465	-5.9	4,016	-4.9	22,962	0.4	65.1
2005	08/09/05	4,193	4.4	01/28/05	3,465	0.0	4,193	4.4	23,407	1.9	63.7
2006	07/31/06	4,650	10.9	12/08/05	3,537	2.1	4,650	10.9	24,419	4.3	59.9
2007	08/07/07	4,528	-2.6	02/06/07	3,945	11.5	4,528	-2.6	26,013	6.5	65.6
2008	07/31/08	4,264	-5.8	01/25/08	3,875	-1.8	4,264	-5.8	25,448	-2.2	67.9
2009	06/25/09	4,262	0.0	01/15/09	3,728	-3.8	4,262	0.0	24,296	-4.5	65.1
2010	07/23/10	4,474	5.0	12/10/09	3,858	3.5	4,474	5.0	25,828	6.3	65.9
2011*	07/21/11	4,837	8.1	12/13/10	3,785	-1.9	4,837	8.1	25,512	-1.2	60.0
Forecast											
2012		4,527	-6.4		3,932	3.9	4,527	-6.4	26,169	2.6	66.0
2013		4,613	1.9		4,007	1.9	4,613	1.9	26,621	1.7	65.9
2014		4,597	-0.4		3,988	-0.5	4,597	-0.4	26,500	-0.5	65.8
2015		4,579	-0.4		3,963	-0.6	4,579	-0.4	26,366	-0.5	65.7
2016		4,558	-0.5		3,930	-0.8	4,558	-0.5	26,244	-0.5	65.7
2017		4,560	0.0		3,915	-0.4	4,560	0.0	26,158	-0.3	65.5
2018		4,550	-0.2		3,894	-0.5	4,550	-0.2	26,039	-0.5	65.3
2019		4,545	-0.1		3,878	-0.4	4,545	-0.1	25,956	-0.3	65.2
2020		4,536	-0.2		3,856	-0.6	4,536	-0.2	25,907	-0.2	65.2
2021		4,563	0.6		3,874	0.5	4,563	0.6	25,978	0.3	65.0
2022		4,580	0.4		3,882	0.2	4,580	0.4	26,044	0.3	64.9
2023		4,605	0.5		3,888	0.2	4,605	0.5	26,152	0.4	64.8
2024		4,628	0.5		3,898	0.3	4,628	0.5	26,308	0.6	64.9
2025		4,676	1.0		3,935	0.9	4,676	1.0	26,484	0.7	64.7
2026		4,713	0.8		3,959	0.6	4,713	0.8	26,659	0.7	64.6
2027		4,750	0.8		3,983	0.6	4,750	0.8	26,834	0.7	64.5
2028		4,780	0.6		4,000	0.4	4,780	0.6	27,023	0.7	64.5
2029		4,828	1.0		4,029	0.7	4,828	1.0	27,215	0.7	64.4
2030		4,870	0.9		4,057	0.7	4,870	0.9	27,416	0.7	64.3
2031		4,912	0.9		4,088	0.8	4,912	0.9	27,622	0.8	64.2

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

	Supply						Demand						Notes	
Year	Owned Generating Capacity (MW)	Incremental Capacity Additions (MW)	Incremental Capacity Reductions / Derates (MW)	Total Multi-Year Purchases (MW)	Annual Purchases (MW)	Total Supply Resources (MW)	Peak Internal Demand (MW)	Total Sales (MW)	Total Conservation (MW)	Total Demand Response (MW)	Net Peak Demand (MW)	Reserve Margin (%)	Capacity Additions	Capacity Reductions
2012	5,493		(3)	11	0	5,501	4,544	175	(258)	(23)	4,438	24.0%		Kyger Creek 1-5 FGD
2013	5,490	13	(2)	11	0	5,512	4,656	151	(258)	(49)	4,500	22.5%	100 MW Wind	Clifty Creek 1-6 FGD
2014	5,501	13		13	0	5,527	4,687	0	(258)	(123)	4,306	28.4%	100 MW Wind	
2015	5,514	13	(485)	13	0	5,055	4,710	0	(258)	(186)	4,266	18.5%	100 MW Wind	Tanners Creek 1-3 Retirement
2016	5,042	38	(30)	12	0	5,063	4,724	0	(258)	(249)	4,217	20.1%	Rockport 1 Valve Uprate & Seasonal Derate Removal	Rockport 1 FGD
2017	5,051			12	0	5,063	4,763	0	(258)	(313)	4,192	20.8%		
2018	5,051			12	0	5,063	4,791	0	(258)	(353)	4,180	21.1%		
2019	5,051			12	0	5,063	4,820	0	(258)	(389)	4,173	21.3%		
2020	5,051	43		12	0	5,105	4,827	0	(258)	(408)	4,161	22.7%	100 MW Wind & Rockport 2 Valve Uprate	
2021	5,093			12	0	5,105	4,856	0	(258)	(412)	4,186	22.0%		
2022	5,093			12	0	5,105	4,874	0	(258)	(415)	4,201	21.5%		
2023	5,093			12	0	5,105	4,899	0	(258)	(418)	4,223	20.9%		
2024	5,093	562		13	0	5,668	4,921	0	(258)	(419)	4,244	33.6%	562 MW CC	
2025	5,655		(500)	13	0	5,168	4,970	0	(258)	(423)	4,289	20.5%		Tanners Creek 4 Retirement
2026	5,155			13	0	5,168	5,007	0	(258)	(423)	4,326	19.5%		
2027	5,155	13		13	0	5,181	5,044	0	(258)	(423)	4,363	18.8%	100 MW Wind	
2028	5,168			13	0	5,181	5,073	0	(258)	(422)	4,393	17.9%		
2029	5,168			12	0	5,180	5,122	0	(258)	(423)	4,441	16.6%		
2030	5,168			12	0	5,180	5,164	0	(258)	(423)	4,483	15.6%		
2031	5,168			12	0	5,180	5,206	0	(258)	(423)	4,525	14.5%		
Total		695	(1,020)											

* 13% capacity factor assumed for wind (100 MW Windfarm equates to 13MW RTC)
** I&M owns 18.06% of OVEC capacity as well as all uprates and derates
*** I&M owns 85% percent of RKP1 and RKP2 as well as all uprates and derates
**** This sheet reflects a "Traditional" Summer View

Indiana Michigan Power Company

Load Research Class Interval Usage Estimation Methodology

Load Research Class Interval Usage Estimation Methodology

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 the MV90 Load Research Package. This industry accepted program combines the individual customer hourly data for each sample point in each stratum, weights the stratum results according to the original sample design parameters, and combines the weighted stratum results into class level results. 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 Kema 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.