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Indiana Municipal Power Agency

2011 Integrated Resource Plan

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EXECUTIVE SUMMARY

As part of its normal planning and risk management activities, the Indiana Municipal Power Agency (IMPA) regularly reviews its projected loads and the resource options available to meet those loads in an economical, reliable and environmentally responsible manner. Pursuant to the requirements of 170 IAC 4-7, IMPA is pleased to present this Integrated Resource Plan (IRP). This filing updates the plan submitted in November, 2009. This report assesses IMPA's options to meet its members' energy requirements for wholesale electric service from 2012 through 2031.

Integrated resource planning involves the consideration of both supply-side and demand-side resources to meet the future resource needs of an electric utility and its customers. Both types of resources are compared based on their ability to meet the utility's objectives. IMPA's primary objective in developing its IRP is to minimize the cost of electricity service to its member utilities and their customers while maintaining a reliable and environmentally responsible wholesale supply of electricity at stable prices. Additional objectives include minimizing risk through a diverse mix of resources and maintaining flexibility to respond to changing conditions.

In 2011, IMPA's coincident peak demand for the 54 communities that IMPA currently serves was 1,226 MW. IMPA began serving the Town of Straughn, Indiana on December 1, 2010. The annual energy requirements for the 53 communities IMPA served during 2010 were 6,118,834 MWh. IMPA has projected that its peak demand will increase at a rate of just under 1% per year from 2012 through 2031 and that its annual energy requirements will increase at a slightly lower rate over the same period. These projections do not include the addition of any new IMPA members or customers beyond those currently under contract, nor do they include IMPA's planned energy efficiency measures to be discussed later in this report.

IMPA uses both supply-side and demand-side resources to meet its peak demand and energy requirements. Current supply-side resources include:

- Joint ownership interests in Gibson Station Unit 5 and Trimble County Units 1 and 2;
- Seven combustion turbines wholly owned by IMPA;
- Generating capacity owned by four IMPA members, dedicated to IMPA;
- Firm power purchases from:
    - Indiana Michigan Power Company (I&M), a subsidiary of American Electric Power (AEP);
    - Duke Energy Indiana (DEI);

In October 2008, IMPA signed a ten year purchased power agreement for up to 50 MW of wind energy from the Crystal Lake Wind Energy Center in Hancock County, Iowa. The expected renewable energy from this contract will meet approximately 2% of IMPA's energy needs.

IMPA has also contracted for shorter term purchases from various utilities and power marketers in the Midwest Independent System Operator (MISO) and PJM Interconnection (PJM) energy markets.

Current demand-side resources include member programs, such as off-peak and interruptible rates, whose effects are reflected in the load forecast, as well as IMPA programs, such as the Commercial and Industrial (C&I) prescriptive rebates, online home energy audits, IMPA communications and educational efforts, retail customer generation and a net metering program.

In 2004, the Indiana Utility Regulatory Commission (IURC) approved in Cause No. 42455 IMPA's generation expansion plan, including IMPA's acquisition of and participation in several generation projects.

IMPA completed acquisition of Georgetown Units 2 and 3 in 2004. Trimble County Unit 2 was completed and placed in service in January of 2011. The Prairie State Project is currently under construction with both units expected to be in commercial operation in 2012. The proposed Thoroughbred Project has been cancelled.

IMPA's existing and planned generation resources are diverse in terms of size, fuel type and source, geographic location, type of resource, and vintage. IMPA owns or controls generation in MISO and PJM, as well as in the Louisville Gas & Electric (LG&E)/Kentucky Utilities control area. After Prairie State comes online, IMPA will own and/or be contracted to resources in eight (8) different local balancing authorities in Indiana, Illinois, Iowa and Kentucky. This diversity reduces IMPA's exposure to such risks as forced outages, volatility in locational marginal prices, catastrophic equipment failures, strikes, and unexpected increases in fuel costs. As part of its risk management activities, IMPA utilizes market purchases to cover short energy positions due to economics or planned unit maintenance outages. New legislative and regulatory developments such as the recently enacted Cross-State Air Pollution Rule (CSAPR) as well as pending and potential legislative and regulatory developments, including Mercury and Air Toxics Rule, potential CO_2 legislation to mandate reduced CO_2 emissions and potential Renewable Portfolio Standard (RPS) legislation, present a challenging resource planning environment for IMPA.

As discussed in the body of this IRP, IMPA has considered a variety of potential supply-side and demand-side resources, taking into account such factors as load growth, EPA rules, energy efficiency and other variables that will influence the ultimate plan. IMPA's analysis is based upon a strategic plan that calls for IMPA to aggressively pursue energy efficiency as well as the acquisition/utilization of no-carbon or low-carbon resources (no/low carbon resources).

A consideration underlying this IRP is IMPA's strategic determination to target supplying 40% of its current energy forecast with energy efficiency measures, renewable resources and no/low carbon resources by 2020. Accordingly, the expansion plan included in this IRP envisions large reductions in energy and demand requirements through the broad expansion of IMPA's demand response and energy efficiency programs. Specific programs that IMPA is considering in this area are described in Part IV. The extent to which such programs are implemented and successful in reducing demand and energy requirements could change the timing, quantity and mix of the resources shown in the resource expansion plan.

IMPA's analysis identified the following resource expansion plan through 2022:

Year	Capacity – MW	Resource Type
2012	-	-
2013	-	-
2014	-	-
2015	-	-
2016	75	CT
2017	75	CT
	50	Wind/Renew
2018	50	Wind/Renew
2019	50	Wind/Renew
2020	50	Wind/Renew
2021	-	-
2022	-	-

The resource expansion plan is described more fully in Part V.

Although this plan has focused on wind generation to expand renewable resources, IMPA is also exploring other renewable generation options, such as generation from landfill gas or solar, which could substitute for or supplement wind generation. Additionally, active customer participation in IMPA member's net metering tariffs could result in more renewable energy on IMPA's system.

IMPA is not proposing the acquisition of any specific resource based on the results of this study. Rather, as discussed in its action plan below, IMPA will continue to evaluate resource options in light of future developments and will bring any firm proposals for specific resources requiring regulatory approval to the IURC at the appropriate time.

ACTION PLAN

IMPA proposes the following actions over the next 24 months.

For Supply-Side Programs:

- Complete the development of the Prairie State Project.
- Continue investigating options that may lead to IMPA's purchasing power from, obtaining an ownership interest in or constructing other resources to serve its need for future capacity and energy in PJM and MISO.
- Investigate and seek out renewable energy resources (wind, solar, biomass, and landfill gas generators).
- Continue to evaluate available purchased power contracts to optimize their utilization given IMPA's loads and existing resources.
- Continue to seek ways to better utilize IMPA-owned resources to minimize costs.

For Demand-Side Programs:

- Actively participate in the DSMCC's Statewide Third Party Administrator Core Programs
- Analyze and evaluate the results of the 2012-2013 Statewide Core program participation to determine next steps
- Investigate and Implement additional Energy Efficiency programs such as
    - Custom Commercial and Industrial Audits
    - Residential Appliance Rebates
    - HVAC and Home Envelope
    - Refrigerator Turn-in
    - Commercial and Industrial Demand Response
- Continue enhancements to IMPA's web site to include additional energy efficiency, conservation and safety information for retail consumers
- Continue to support IMPA members' independent investigation and implementation of energy efficiency measures that are unique to their systems and facilitate the transfer of knowledge and lessons learned among members.
- Continue to offer members educational materials such as bill stuffers, brochures and other media that explain and encourage energy efficiency and electrical safety.

PART I - INTRODUCTION

The following describes IMPA's 2011 IRP. This report complies with the requirements of 170 IAC 4-7, which requires the submission of IMPA's IRP on a biennial basis. The following sections provide a short history of IMPA's power supply resource acquisition, an overview of IMPA's resource planning activities since the last IRP submitted 2009 and an overview of IMPA's planning process.

IMPA HISTORY

Pursuant to the provisions of Indiana Code § 8-1-2.2 et seq., IMPA was created in 1980 by 24 member municipalities for the purpose of undertaking the planning, financing, ownership and operation of projects to supply electric power and energy for the present and future needs of the members. IMPA has entered into separate power sales contracts and power supply agreements with each of its members to supply all their electric power and energy requirements. IMPA began serving its members on January 27, 1983.

In addition to increasing its membership/customers from the initial 24 to 54 cities and towns, major milestones in IMPA's history include:

Fall 1982	Acquired an ownership share of Gibson Unit 5 (Gibson 5)
Fall 1985	Acquired an ownership share of the Joint Transmission System (JTS).
Spring 1992	Placed Richmond Combustion Turbine Units 1 and 2 into commercial operation
Summer 1992	Placed Anderson Combustion Turbine Units 1 and 2 into commercial operation
Fall 1993	Acquired an ownership share of Trimble County Unit 1
Spring 2004	Placed Anderson Combustion Turbine Unit 3 into commercial operation
Fall 2004	Acquired Units 2 and 3 of the Georgetown Combustion Turbine Station

Fall 2007	Construction began at the Prairie State Energy Campus
Fall 2008	Signed first wind energy purchased power agreement
Winter 2011	Placed Trimble County Unit 2 into commercial operation.

ACTIVITIES SINCE LAST IRP

Since IMPA submitted its last Integrated Resource Plan to the IURC on November 1, 2009, the following events have taken place:

- On June 11, 2010, IMPA received a $5 million DOE grant for the installation of LED Street Lights. In total, thirty- one IMPA communities installed over 10,600 LED street lights with annual energy savings of approximately 6,500 MWh.

- In the summer of 2010, IMPA completed construction of three renewable energy demonstration facilities at its Carmel, Indiana office complex. The facilities are a 1.2 kW solar hot water heating system, a 6.4 kW solar electric system and a 1.3 kW wind turbine.

- On September 24, 2010, the IMPA Board approved Statewide Core energy efficiency program participation for all of IMPA's members.

- On October 14, 2010, IMPA closed on the sale of its Power Supply System Revenue Bonds, 2010 Series A & B. The primary purpose of the bonds was to fund IMPA's portion of the costs to construct and place into service the Prairie State Energy Campus.

- On December 1, 2010, IMPA began serving the Town of Straughn, Indiana.

- On December 10, 2010, the Board approved IMPA demand response tariffs applicable for MISO and PJM. These tariffs allow IMPA's member communities to offer participation in certain MISO and PJM demand response initiatives to eligible retail customers.

- On January 22, 2011, Trimble County Unit 2 was placed in commercial service.

- In May 2011, IMPA successfully completed a NERC 693 Compliance Audit with no findings.

- In July 2011, IMPA successfully completed a NERC CIP Audit with no findings.

- On October 4, 2011, IMPA closed on the Sale of its Power Supply System Revenue Bonds, 2011 Series A. The primary purpose of the bonds was to refund callable bonds issued in 2002 at lower interest rates, resulting in present values savings of approximately $5.6 million and to fund ongoing capital expenditures for various capital improvements to Gibson 5, Trimble County, IMPA's combustion turbines and the JTS.

INTEGRATED RESOURCE PLANNING PROCESS

Integrated resource planning involves the consideration of both supply-side and demand-side resources to meet the future resource needs of an electric utility and its customers. Both types of resources are compared based on their ability to meet the utility's objectives. IMPA's primary objective in developing its IRP is to minimize the cost of electricity to its member utilities and their customers, while maintaining a reliable and environmentally responsible electricity supply. Additional objectives include minimizing risk through a diverse mix of resources and maintaining flexibility to respond to changing economic and regulatory conditions.

The IRP process begins with an evaluation of existing loads and resources. This evaluation, which is described in Part II, establishes the basis for future resource planning by identifying the expected future availability of existing supply-side and demand-side resources including possible upgrades, expansions or retirements of those resources.

The next step is the development of a long-range forecast of peak demand and energy requirements. Part III describes IMPA's development of a 20-year projection of peak demands and annual energy requirements. IMPA developed its load forecast using a time-series, linear regression equation for each load zone.

The third step in the integrated resource planning process is the identification of future supply-side and demand-side resource options. IMPA's primary options are described in Part IV. On the supply side, IMPA owns a portfolio of generation resources and has in place contracts with other utilities that allow it to purchase firm power to meet a portion of its existing load and some of its future load growth. On the demand side, IMPA does not serve any retail customers. Since demand-side resources involve programs that influence the electricity consumption patterns of retail customers, IMPA's role in the implementation of such programs has historically been limited to providing appropriate rate signals to its members, disseminating information to its members on energy efficiency, energy conservation, demand-side management programs and their potential economic benefit, and where appropriate, coordinating member programs to take advantage of economies of scale. In recent years, IMPA has been authorized by its Board to invest in and take a more direct role in the promotion of energy efficiency programs in its member communities.

The evaluation of resource options is described in Part V. A short-term action plan is described in Part VI.

GUIDELINES FOR INTEGRATED RESOURCE PLANNING

The IURC developed guidelines in 170 IAC 4-7 *et seq.* for electric utilities' development of IRPs. Table 1 summarizes the guidelines, along with an index of IMPA's response to that guideline.

Indiana Municipal Power Agency
170 IAC 4-7

Citation	Description	IMPA's Response
170 IAC 4-7-4 (1) through (6)	Load forecasting matters	See Part III
170 IAC 4-7-4 (7) through (9)	Criteria and planning practices for generation	See Part II for existing generation and Part V for potential future generation
170 IAC 4-7-4 (10) through (14)	Transmission matters	FERC Form 715 prepared by DEI for the JTS
170 IAC 4-7-4 (15)	System Reliability Improvement	IMPA complies with the applicable NERC requirements.
170 IAC 4-7-4 (16)	Avoided Costs	See Part V
170 IAC 4-7-4 (17)	Hourly load data, System Lambda	See accompanying CD
170 IAC 4-7-4 (18)	Public Participation Procedure	IMPA's IRP is presented to the IMPA Board of Commissioners on two occasions, with formal approval taking place after initial Board input and the second presentation.
170 IAC 4-7-5	Energy and demand forecasts	See Part III
170 IAC 4-7-6	Resource assessment	See Part II for existing generation and DSM, and see Part V for potential future generation and DSM
170 IAC 4-7-7	Selection of future resources	See Part V
170 IAC 4-7-8	Resource integration	See Part V
170 IAC 4-7-9	Short term action plan	See Part VI

Table 1 - 170 IAC 4-7

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PART II - EXISTING SYSTEM

IMPA is a wholesale electric utility serving the total electricity requirements of 54 communities. Each of IMPA's 53 members is an Indiana city or town with a municipally owned electric utility. IMPA also serves the Village of Blanchester, Ohio on a full-requirements contractual basis very similar to its member contracts, except for specific provisions applicable to Indiana municipalities (the most significant being that Blanchester does not have a seat on IMPA's Board of Commissioners). IMPA's member and customer communities are located in five different local balancing areas and two different Regional Transmission Organizations (RTOs). Table 2 lists the 54 communities that IMPA serves along with the load zone and RTO in which they are located.

Indiana Municipal Power Agency
IMPA Communities

RTO	Load Zone	Community
MISO	Duke - IN	Advance, Bainbridge, Bargersville, Brooklyn, Centerville, Covington, Crawfordsville, Darlington, Dublin, Dunreith, Edinburgh, Flora, Frankfort, Greendale, Greenfield, Jamestown, Knightstown, Ladoga, Lawrenceburg, Lebanon, Lewisville, Linton, Middletown, Paoli, Pendleton, Peru, Pittsboro, Rising Sun, Rockville, Scottsburg, Spiceland, Straughn, Thorntown, Tipton, Washington, Waynetown
	NIPSCO	Argos, Bremen, Brookston, Chalmers, Etna Green, Kingsford Heights, Rensselaer, Walkerton, Winamac
	Vectren	Huntingburg, Jasper, Tell City
PJM	AEP	Anderson, Columbia City, Frankton, Gas City, Richmond
	Duke - OH	Blanchester, Ohio

Table 2 - IMPA Communities

The following sections describe IMPA's loads and load characteristics as well as its existing and planned resources. In August 2004, the IURC issued an Order in Cause No. 42455 authorizing IMPA to acquire certain additional generating resources. Pursuant to this Order, IMPA consummated its acquisition of two combustion turbines at the Georgetown Combustion Turbine Station, completed construction of and placed Trimble County Unit #2 in service and is currently participating in the construction of the Prairie State Energy Campus. The Thoroughbred Project, which was proposed as part of this generation expansion project, has been cancelled.

LOADS AND LOAD CHARACTERISTICS

In 2011, IMPA's coincident peak demand for its 54 communities was 1,226 MW, and the annual energy requirements for the 53 communities IMPA served during 2010 were 6,112,550 MWh. IMPA began serving the Town of Straughn, Indiana on December 1, 2010. Figures 1 and 2 highlight IMPA's peak demand and annual energy requirements for the past 5 years. (The historic data has been adjusted to include the addition of new members in recent years.)

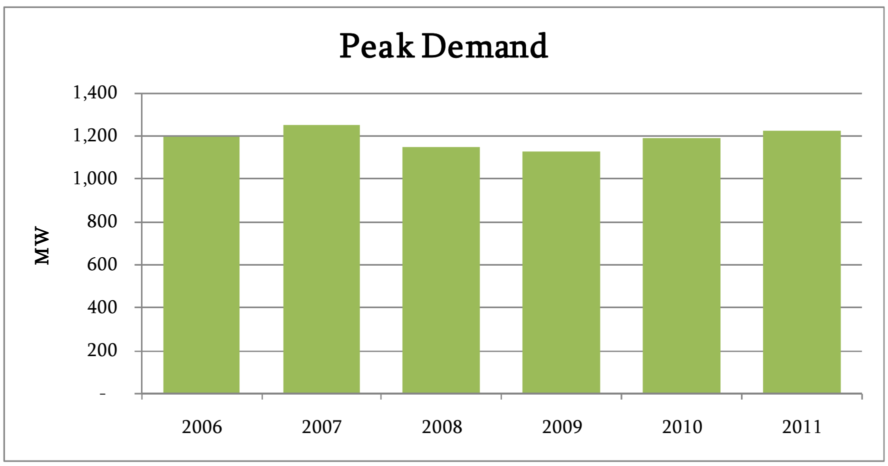

Figure 1 - Historic Peak Demands

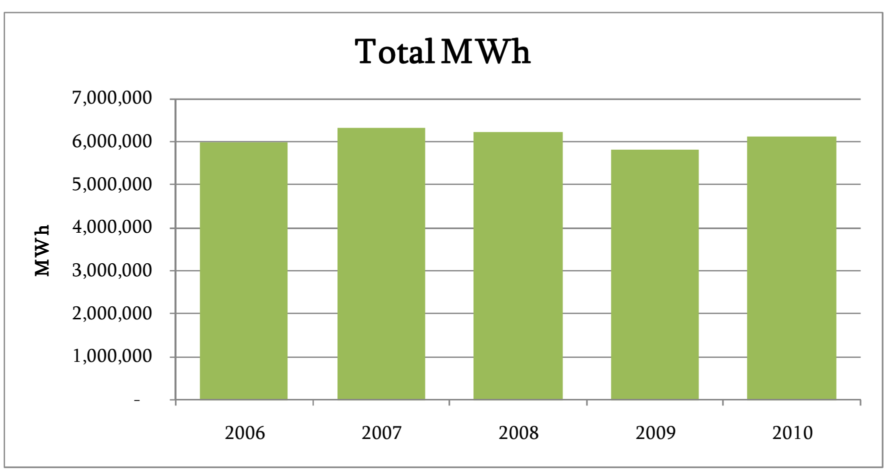

Figure 2 - Historic System MWh

Hourly loads are shown in Appendix A and typical annual, monthly, weekly, and daily load shapes for IMPA as a whole are shown in Appendix B. As a wholesale supplier, IMPA does not have the necessary retail load information to draw conclusions concerning disaggregation of load shapes by customer class or appliance.

EXISTING RESOURCES

IMPA's existing resources include both supply-side and demand-side resources. Supply-side resources include generation resources owned and/or controlled by IMPA and contractual arrangements with other utilities. Demand-side resources include programs implemented by IMPA and its members.

Supply-Side Resources

IMPA currently has a variety of supply-side resources, including ownership interests in Gibson Unit 5 (Gibson 5) and Trimble County Units 1 and 2 (Trimble County 1&2), seven combustion turbines wholly owned by IMPA, generating capacity owned by four of IMPA's members, long-term firm power purchases from I&M and DEI, as well as short term purchases from various utilities and power marketers in the MISO and PJM energy markets. In 2008, IMPA signed a purchased power agreement for up to 50 MW of wind energy from the Crystal Lake Wind Energy Center in Hancock County, Iowa. The expected renewable energy from this contract will meet approximately 2% of IMPA's 2012 energy needs. Some of these resources, such as firm power purchases, have contractual limitations that restrict their use to a particular local balancing area or delivery point. Table 3 summarizes the key characteristics of IMPA's generating units and Table 4 highlights the long term purchased power agreements. The resources and contracts are described in more detail on the following pages.

Indiana Municipal Power Agency
Summary of Existing Generating Resources

Plant Name	Unit	State	In Service Year	Prime Mover	Primary Fuel	Secondary Fuel	Summer Rating (MW)	Winter Rating (MW)	Current Environmental Controls	Comments
Gibson	5	IN	1982	ST	Coal	-	155.0	156.0	D-ESP, FGD, LNB, SCR, CP	MW Rating Represents IMPA's 24.95% Share of Unit
Trimble County	1	KY	1990	ST	Coal	-	66.0	66.0	CT, D-ESP, FGD, LNB, SCR	MW Rating Represents IMPA's 12.88% Share of Unit
Trimble County	2	KY	2011	ST	Coal	-	96.0	96.0	BH, CT, D-ESP, FGD, LNB, SCR, W-ESP	MW Rating Represents IMPA's 12.88% Share of Unit
Anderson	1	IN	1992	CT	Nat Gas	Oil	33.5	42.0	WI	
Anderson	2	IN	1992	CT	Nat Gas	Oil	33.5	42.0	WI	
Anderson	3	IN	2004	CT	Nat Gas	Oil	72.5	85.0	DLN1, WI	WI - only on oil
Georgetown	2	IN	2000	CT	Nat Gas	-	72.5	85.0	DLN1	DLN1 system (Dry Low Nox bruner)
Georgetown	3	IN	2000	CT	Nat Gas	-	72.5	85.0	DLN1	DLN1 system (Dry Low Nox bruner)
Richmond	1	IN	1992	CT	Nat Gas	Oil	33.5	42.0	WI	
Richmond	2	IN	1992	CT	Nat Gas	Oil	33.5	42.0	WI	
Whitewater Valley	1	IN	1955	ST	Coal	-	35.0	35.0	BH, CT, D-ESP, LNB, NOx	
Whitewater Valley	2	IN	1973	ST	Coal	-	64.0	64.0	BH, CT, D-ESP, LNB, NOx, DSI	
Peru	2	IN	1959	ST	Coal	-	12.1	12.1	D-ESP	Exempt from Title IV SO2, NOx SIP Call, AIR and CSAPR
Peru	3	IN	1949	ST	Coal	-	20.0	20.0	D-ESP	Exempt from Title IV SO2, NOx SIP Call, AIR and CSAPR
Peru	Diesel	IN	2002	IC	Oil	-	1.8	1.8		Exempt from Title IV SO2, NOx SIP Call, AIR and CSAPR
Jasper	1	IN	1968	ST	Coal	-	15.0	15.0	D-ESP	Exempt from Title IV SO2, NOx SIP Call, AIR and CSAPR
Rensselaer	5	IN	1950	IC	Oil	-	1.5	1.5		Exempt from Title IV SO2, NOx SIP Call, AIR and CSAPR
Rensselaer	6	IN	1957	IC	Oil	Nat Gas	2.4	2.4		Exempt from Title IV SO2, NOx SIP Call, AIR and CSAPR
Rensselaer	10	IN	1971	IC	Oil	Nat Gas	1.7	1.7		Exempt from Title IV SO2, NOx SIP Call, AIR and CSAPR
Rensselaer	11	IN	1971	IC	Oil	Nat Gas	1.7	1.7		Exempt from Title IV SO2, NOx SIP Call, AIR and CSAPR
Rensselaer	14	IN	1994	IC	Nat Gas	Oil	4.7	4.7		Exempt from Title IV SO2, NOx SIP Call, AIR and CSAPR
Rensselaer	15	IN	2006	IC	Nat Gas	-	8.4	8.4	CO catalyst	Exempt from Title IV SO2, NOx SIP Call, AIR and CSAPR

Prime Movers	Environmental Controls	
ST = Steam Turbine	BH = Baghouse	SCR = Selective Catalytic Reduction
CT = Combined Cycle	CT = Cooling Tower	W-ESP = Wet Electrostatic Precipitator
IC = Internal Combustion	CP = Cooling Pond	WI = Water Injection
	D-ESP = Dry Electrostatic Precipitator	NOx = Other NOx Reduction
	FGD = SO2 Scrubber	DLN1 = Dry Low Nox System 1
	LNB = Low-NOx Burners	DSI = Dry Sorbent Injection

Table 3 - IMPA Generating Resources

Indiana Municipal Power Agency
Summary of IMPA Long Term Purchased Power Contracts

CounterParty	Capacity (MW)	Expiration	Comments
Duke	23.4	12/31/14	PCA Reserve Capacity
Duke	50.0	05/31/17	7x24, 50MW fixed for term
WPPI	50.0	05/31/18	MISO PRC
NextEra	50.0	12/31/18	Wind PPA, Up to 50 MW of wind energy
AEP	190.0	12/31/34	7x24, Can increase capacity annually at IMPA's option

Table 4 - IMPA Purchased Power Agreements

Gibson 5

IMPA has a 24.95% undivided ownership interest in Gibson 5, which it jointly owns with DEI (50.05%) and Wabash Valley Power Association (WVPA) (25.00%). Gibson 5 is a 625-megawatt coal-fired generating facility located in southwestern Indiana. It is equipped with particulate, SO_2 and NO_x removal facilities (SCR) and an SO_3 mitigation process. The boiler has also been retrofitted with low NO_x burners. Fuel supply for Gibson Station is acquired through a number of contracts with different coal suppliers. The coal consists of mostly high sulfur coal sourced from Indiana and Illinois mines. A small amount of low sulfur coal is also purchased. Three contracts make up approximately two-thirds of the coal supply. Procurement is such that the prompt year's supply is nearly completely hedged while future years are partially contracted two to three years in advance. Coal is delivered by both train and truck. The current targeted stockpile inventory is 30-40 days.

DEI operates Gibson 5 under the Gibson Unit No. 5 Joint Ownership, Participation, Operation and Maintenance Agreement (Gibson 5 Agreement) among DEI, IMPA and WVPA. The Gibson 5 Agreement obligates each owner to pay its respective share of the operating costs of Gibson 5 and entitles each owner to its respective share of the capacity and energy output of Gibson 5. Under a Power Coordination Agreement, IMPA purchases reserve capacity and energy from DEI during forced and maintenance outages of Gibson 5.

Gibson 5 currently complies with the sulfur dioxide (SO_2), nitrogen oxide (NO_x), particulate matter and opacity requirements of the Clean Air Act and Phase II of the Acid Rain Program. Gibson 5 also complies with the Clean Air Interstate Rule (CAIR) NO_x and SO_2 regulations in 40 CFR 96 and 326 IAC 24. To date, IMPA's share of the SO_2 and NO_x emissions allowances allocated by the United State Environmental Protection Agency (U.S. EPA) and the Indiana Department of Environmental Management (IDEM) have satisfied IMPA's requirements for such allowances.

On December 23, 2008, the U.S. Court of Appeals for the D.C. Circuit remanded CAIR to U.S. EPA, but did not vacate the rule. This ruling left CAIR in place until the U.S. EPA issued a new rule consistent with the court's decision. The final replacement rule, the Cross-State Air Pollution Rule (CSAPR), was issued by U.S. EPA in July 2011. CSAPR has two phases and will be similar to CAIR in that it will have allowance allocations to existing and new units and allow trading of those allowances albeit with limits on interstate trading. Phase 1 of the rule begins January 1, 2012. Phase 2 begins in 2014 and further reduces SO_2 allowance allocations. Compliance with CAIR is necessary through the end of 2011 unless congressional, court, or executive action extends CAIR and delays CSAPR implementation.

CAIR required reductions in NO_x and SO_2 emissions. The CAIR NO_x program began in 2009 with its first phase and included both ozone season requirements and annual requirements. The second phase, which was to further reduce the state's NO_x allocation from U.S. EPA, was to begin in 2015. There will be separate allowances allocated and allowance accounts set up for the annual and ozone season rules. Gibson 5 complies with the annual and seasonal requirements of the NO_x rule by operating its Selective Catalytic Reduction system (SCR) on an annual basis. IMPA expected its share of allowances in both phases to satisfy the CAIR NO_x emissions of Gibson 5.

The CAIR SO_2 requirements began in 2010 and required that units "cover" each ton of emissions with two (2) SO_2 allowances if the vintage of the allowance was 2010 or later (2009 and earlier vintage allowances could be used on a 1:1 ratio). In 2015 and beyond, each ton of emissions must be "covered" with two and eighty-six hundredths (2.86) allowances. Compliance with the CAIR SO_2 rule at Gibson 5 was aided by a significant investment to upgrade the unit's flue gas desulfurization system (FGD). This upgrade was done during an extended maintenance outage in the spring of 2008 with final modifications being completed in the fall of 2009. IMPA expects its share of allowances to satisfy the CAIR SO_2 emissions of Gibson 5 during the first phase. Beginning in 2012, CSAPR will begin and a new "currency" of allowances will be issued that can be used only for CSAPR. Neither CAIR nor Acid Rain program allowances that have been banked will be transferrable to satisfy CSAPR requirements. IMPA anticipates that Gibson 5's combustion and its FGD will be further optimized to help meet compliance with Phase 1 of CSAPR while the investment strategy for long term compliance is determined. Gibson 5 will likely need to purchase allowances for SO_2 until the investment strategy is determined and potential future capital additions are in place.

The Clean Air Mercury Rule (CAMR), issued by U.S. EPA in March 2005, was vacated February 8, 2008 by the D.C. Circuit Court of Appeals, and the U.S. Supreme Court denied further review of the ruling on February 23, 2009. U.S. EPA's rule removing power plants from the Clean Air Act list of sources of hazardous air pollutants was also vacated at that time. U.S. EPA subsequently announced its decision to develop more encompassing hazardous air pollutant emissions standards for power plants under the Clean Air Act (Section 112, MACT standards) consistent with the D.C. Circuit's opinion vacating CAMR. U.S. EPA issued a proposed rule, Mercury and Air Toxics for Power Plants (MATS), in March 2011. Comments were accepted through August 4, 2011. U.S. EPA is expected to issue the final version of the rule in November 2011.

Non-hazardous solid waste from this bituminous coal fired unit consists of the following coal combustion by-products (CCBs): fly ash, bottom ash, and fixated sludge from the SO_2 scrubber. The solid waste is disposed of in a mono-purpose solid waste disposal facility on the site or beneficially reused in the close out of the East Ash Pond surface impoundments at the site. DEI also actively pursues other alternative reuse of CCBs.

Small quantities of hazardous wastes may be generated from time to time from normal plant activities and may include spent solvents from parts cleaning and paint-related wastes, etc. Gibson Station normally operates as a Small Quantity Generator (<1000 kg per month). All hazardous wastes generated at Gibson Station are properly characterized prior to disposal at appropriately permitted disposal facilities. The specific disposal facility chosen for a given waste depends on the nature of that particular waste.

Trimble County 1

IMPA has a 12.88% undivided ownership interest in Trimble County 1, which is jointly owned with LG&E (75.00%) and the Illinois Municipal Electric Agency (IMEA) (12.12%). Trimble County 1 is a 514-MW coal-fired unit located in Kentucky on the Ohio River approximately 15 miles from Madison, Indiana. The unit is equipped with particulate, SO_2 and NO_x removal facilities and an SO_3 mitigation process. The boiler burners have been modified to meet the nitrogen oxide limits of Phase II of the Acid Rain Program. To date, IMPA's share of the SO_2 and NO_x emissions allowances allocated by EPA and the Kentucky Energy and Environment Cabinet have satisfied IMPA's requirements for such allowances. Trimble County 1 burns high sulfur coal. LG&E purchases coal on a system basis and delivers it on an economic basis to its various power plants. The majority of this coal is from mines in

Indiana and Kentucky. All coal is delivered to Trimble County by barge. Due to barge delivery, stockpile inventory levels fluctuate within a targeted 28 to 49 day level.

LG&E operates Trimble County 1 under a Participation Agreement between LG&E, IMEA and IMPA (Trimble County 1 Agreement). The Trimble County 1 Agreement obligates each owner to pay its respective share of the operating costs of Trimble County 1 and entitles each owner to its respective share of the capacity and energy output of Trimble County 1.

Trimble County 1 currently complies with the SO_2, NO_x, particulate matter, and opacity requirements of the Clean Air Act. Trimble County 1 also complies with the Clean Air Interstate Rule (CAIR) NO_x and SO_2 regulations in 40 CFR 96 and 401 Kentucky Administrative Rule 51.

Trimble County 1 complies with the CAIR NO_x rules by operating the SCRs on an annual basis. IMPA expects its share of allowances to satisfy the CAIR NO_x emissions at Trimble County. Compliance with the CAIR SO_2 rule is accomplished through the increased efficiency achieved through the significant investment made to upgrade the Trimble County 1 flue gas desulfurization system (FGD) in the fall of 2005. IMPA expects its share of allowances to satisfy the CAIR SO_2 emissions of Trimble County 1. Compliance with CAIR is necessary through the end of 2011 unless congressional, court, or executive action extends CAIR and delays CSAPR implementation.

Trimble County 1 is also affected by CSAPR. IMPA expects the allowances allocated by the U.S. EPA for Trimble County 1 to be sufficient to cover its emissions in Phase 1 and Phase 2 of CSAPR.

Solid waste from the bituminous coal consumed in the unit consists of the following CCBs: fly ash, bottom ash, and gypsum from the SO2 scrubber. The solid waste is disposed of in a surface impoundment on the site or beneficially reused by marketing the CCBs to third parties. LGE actively pursues alternative reuse of CCBs.

Any hazardous waste generated at Trimble County is analyzed to confirm the hazardous nature and then profiled with LGE's hazardous waste contractor for disposal by either incineration or placement in a certified Class C landfill. The facility maintains manifest and disposal records for all hazardous waste shipped off site.

Trimble County 2

IMPA recently constructed Trimble County 2 jointly with LG&E and Kentucky Utilities (collectively LG&E) and Illinois Municipal Electric Agency (IMEA). Trimble County 2 is a nominal 750 MW (net) unit with a supercritical, pulverized coal boiler and a steam-electric turbine generator. The boiler will have low-NO_x burners, an SCR, a dry electrostatic precipitator, pulse jet fabric filters, wet flue gas desulfurization, and a wet electrostatic precipitator. The coal will be eastern bituminous coal (including, potentially, Indiana coal) blended with western sub-bituminous coal. All coal will arrive at the site via barge on the Ohio River. LG&E plans to use the same procedures for selection and delivery of coal to Trimble County 2 as it currently uses for Trimble County 1. Trimble County 2 will exhaust through two new flues in the existing site chimney. Trimble County 2 began commercial operation in January 2011.

The ownership arrangement for Trimble County 2 has the same percentages as for Trimble County 1: LG&E at 75%, IMPA at 12.88% and IMEA at 12.12%. LG&E is acting as operating agent for the owners.

As with Trimble County 1, compliance with CAIR is necessary through the end of 2011 unless congressional, court, or executive action extends CAIR and delays CSAPR implementation.

Trimble County 2 is also affected by CSAPR. Trimble County 2 will be considered a new unit under CSAPR and will be allocated allowances from Kentucky's new unit set-aside pool. IMPA expects that the allowances allocated by the U.S. EPA for Trimble County 2 will be sufficient to cover its emissions in Phase 1 and Phase 2 of the rule.

Solid waste from the bituminous and sub-bituminous coal consumed in the unit consists of the following CCBs: fly ash, bottom ash, and gypsum from the SO2 scrubber. The solid waste is disposed of in a surface impoundment on the site or beneficially reused by marketing the CCBs to third parties. LGE actively pursues alternative reuse of CCBs.

Any hazardous waste generated at Trimble County is analyzed to confirm the hazardous nature and then profiled with LGE's hazardous waste contractor for disposal by either incineration or placement in a certified Class C landfill. The facility maintains manifest and disposal records for all hazardous waste shipped off site.

General Statement Regarding Regulatory Status of CCBs

The utility industry is now likely faced with a more stringent regulatory scheme for managing CCBs due to the USEPA's consideration of new regulations for CCBs (now referred to by USEPA as "coal combustion residuals"). The EPA issued a proposed rule on June 21, 2010. Comments were taken through November 19, 2010 on the two alternatives that were proposed. A final EPA rule is expected by the end of 2011.

IMPA Combustion Turbines

IMPA has seven wholly-owned combustion turbines and appurtenant facilities. Three units are located in Anderson, Indiana (Anderson Station), two units are located near Richmond, Indiana (Richmond Station), and two units are located at the Georgetown Combustion Turbine Station in Indianapolis, Indiana (Georgetown Station).

IMPA operates and maintains the Anderson and Richmond Stations with on-site personnel. The original four machines are GE-6Bs and Anderson Unit #3 is a GE-7EA. These units operate primarily on natural gas, with No. 2 fuel oil available as an alternate fuel. Natural gas is delivered under an interruptible contract with Vectren. This contract gives IMPA the option to obtain its own gas supplies from various sources with gas transportation supplied by Vectren. IMPA maintains an inventory of No. 2 fuel oil at each station.

IMPA is the sole owner of Units 2 and 3 at the Georgetown Station. Indianapolis Power & Light (IPL) operates these two units on behalf of IMPA as well as the other two units at this station. The units are both GE-7EA machines and are gas fired. Citizens Gas delivers the gas to the Station from the Panhandle Eastern pipeline system. IPL has the responsibility to ensure IMPA's units comply with applicable environmental requirements.

All of IMPA's Combustion Turbine stations comply with the existing requirements of the Clean Air Act. This compliance is achieved through Title V Operating Permit restrictions on fuel consumption and the use of lean pre-mix fuel/air injectors or water injection for NO_x control. The stations meet CAIR emission allowance requirements with allocated and purchased allowances. The stations comply with their respective Acid Rain Permits using the Excepted Methodologies in 40 CFR 75. SO_2 allowances are either purchased or transferred from other IMPA-owned source allocations.

IMPA expects to "cover" the CAIR NO_x emissions of its combustion turbines with its allocated and banked allowances in both phases of the program. Compliance with the CAIR SO_2 rule will be accomplished by the utilization of ultra low-sulfur fuel oil in its Richmond and Anderson combustion turbines. The Georgetown Combustion Turbines operate only on natural gas. IMPA will "cover" its combustion turbines' SO_2 emissions with banked or purchased allowances to ensure CAIR SO_2 compliance.

Compliance with CAIR is necessary through the end of 2011 unless Congressional, court, or Executive action extends CAIR and delays CSAPR implementation.

The combustion turbines are affected by the CSAPR. IMPA expects the allowances allocated by the U.S. EPA for the combustion turbines to be sufficient to cover its emissions in Phase 1 and Phase 2 of the rule but may have to procure a small number of SO_2 allowances if a significant amount of ultra low-sulfur fuel oil were to be consumed at its Richmond or Anderson facilities.

The Anderson and Richmond turbines can operate on pipeline natural gas or No. 2 low sulfur fuel oil. There is no significant environmental effect from solid waste disposal or hazardous waste disposal. Each plant has chemical storage for use in its demineralized water treatment plant. At times hazardous waste may need to be disposed of when the chemical tanks are cleaned. A licensed contractor is hired to do this cleaning, remove the waste, and properly dispose of the waste. There may, at infrequent times, be oily waste removed from the site. This waste is also disposed of using properly licensed vendors. Other waste disposal is similar to household waste and is removed by a licensed refuse removal company.

The Georgetown units are single fuel units that operate solely on pipeline natural gas. There is no chemical storage on site and the plant's parts washer contains non-hazardous solvent. There is no significant environmental effect from solid waste disposal or hazardous waste disposal. Most waste disposal consists of waste similar to household waste and is removed by a licensed refuse removal company. There may, at infrequent times, be oily waste from the site. This waste is also disposed of using properly licensed vendors.

Member-Owned Capacity

IMPA members Richmond, Jasper, Peru and Rensselaer own generating facilities. These members have executed agreements with IMPA providing that the member maintains its generating units and IMPA schedules them against an appropriate Locational Marginal Price (LMP) determined by PJM or MISO.

Richmond's Whitewater Valley Station (WWVS) consists of two coal-fired generating units with a current maximum tested capability of approximately 35.0 MW and 64.0 MW, respectively. Richmond purchases coal on a short-term and spot market basis. Coal is delivered by rail and truck. Stockpile inventory is targeted for a range of 28 to 38 days (approximately 33,000 tons).

WWVS complies with the existing requirements of the Clean Air Act. WWVS is subject to NO_x control requirements. The boilers have low-NO_x burners and overfire air to achieve compliance with the Phase II Acid Rain provisions of the Clean Air Act Amendments of 1990 (CAAA). To meet previous and current NO_x requirements, Richmond installed Mobotec's NO_x-reduction equipment. As needed, Richmond purchases SO_2 and NO_x emissions allowances to supplement those allowances allocated by U.S. EPA and IDEM.

The CAIR required further reductions in NO_x and SO_2 at WWVS. WWVS will comply with each CAIR NO_x rule by operating its Mobotec system on an annual basis. WWVS will use its share of allowances and possibly supplemental allowance purchases in both phases to "cover" its CAIR NO_x emissions. Compliance with the CAIR SO_2 rule will be accomplished by utilizing its existing furnace sorbent injection system and its recently installed baghouse filter system, which will allow more efficient and effective SO_2 and particulate removal. Other future equipment modifications are also being considered to further reduce SO_2 emissions. WWVS expects to utilize its allocated allowances, supplemented with purchases if necessary, to satisfy the CAIR SO_2 emissions during the first and second phases of the program. The CSAPR affects the WWVS units which would require WWVS to utilize its allocated CSAPR allowances and supplement with purchases if necessary if WWVS continues to operate as they have in the past.

Jasper's generating plant consists of one coal-fired unit. Its demonstrated capability is 15.0 MW. Jasper purchases its coal under a multi-year contract, and it is delivered by truck. Jasper maintains an inventory of approximately seven days. The generating unit is exempt from the Title IV acid rain, NO_x SIP Call provisions of the CAAA, CAIR, and CSAPR.

Peru's generating plant consists of two coal-fired units (Units 2 and 3) and one black-start diesel. Unit 3 has a tested capacity of 12.1 MW, Unit 2's tested capability is 20.0 MW, and the black-start diesel has a tested capability of 1.8 MW. Coal for Peru's generating plant is purchased on a short-term and spot market basis. Coal is delivered by truck. Due to limited storage area, proximity to residential neighbors, and the inability to compact the coal to prevent spontaneous combustion fires, Peru limits its stockpile to between 500 and 800 tons of coal inventories (2 to 3 days supply). The Peru generating plant is exempt from the Title IV acid rain provisions of the CAAA, CAIR, and CSAPR requirements as well because both units are under 25 MW.

Rensselaer's generating plant consists of six internal combustion engines with a total tested capability of approximately 20.4 MW. Four of the six machines are designed to operate on natural gas and No. 2 diesel fuel oil. Unit 5 can operate on diesel only and Unit 15 on natural gas only. Units 6, 10 and 11 are currently operated on No. 2 fuel oil only. Unit 14 is dual fuel capable and burns natural gas as a primary fuel with fuel oil as either a backup or mixture. Natural gas is supplied by the City of Rensselaer Gas Company via pipeline supply. No. 2 fuel oil is purchased on an annual contract basis based on competitive bidding. The plant has a storage capacity of 65,000 gallons but routinely targets an inventory supply of 20,000 to 24,000 gallons. The Rensselaer generating plant is exempt from the Title IV Acid Rain provisions of the CAAA, CAIR and CSAPR requirements since all the units are under 25 MW.

IMPA previously had an agreement with Crawfordsville's generating plant. In 2011, this agreement was terminated at the request of Crawfordsville Electric Light and Power.

Firm Power Purchases

On January 1, 2006, IMPA began taking firm power and energy from I&M under a "Cost-Based Formula Rate Agreement for Base Load Electric Service." Initially, this agreement provided IMPA with base load power and energy for a twenty-year period. The initial contract quantity under this agreement was 150 MW. IMPA may increase its purchases by up to 10 MW each year to a maximum delivery of 250 MW. The current contract quantity is 190 MW. I&M's demand and energy charges are calculated each year according to a formula that reflects the previous year's costs with an annual "true-up" the following year. I&M is responsible for providing the capacity reserves under this contract. The contract was extended in 2010 and now has an expiration date of May 31, 2034.

On June 1, 2007, IMPA began taking firm power and energy from DEI under a "Power Sale Agreement for Firm Energy and Capacity." This agreement provides IMPA with 50 MW of base load power and energy. DEI recalculates its demand and energy charges each year according to a formula that reflects the previous year's costs with an annual "true-up" the following year. DEI is responsible for providing the capacity reserves under this contract. This contract expires May 31, 2017.

On June 1, 2007, a new Power Coordination Agreement between IMPA and DEI became effective. Pursuant to this agreement, DEI provides Reserve Capacity, Back-Up Energy and Planning Reserves, and other similar services related to IMPA's entitlement share of Gibson 5. This agreement expires December 31, 2014 at which time IMPA will need to supply the reserves for its share of Gibson 5.

Other Power Purchases

On October 7, 2008, IMPA entered into a contract with Crystal Lake Wind, LLC for the purchase of up to 50 MW of wind energy from the Crystal Lake Wind Energy Center in Hancock County, Iowa. Deliveries under the contract commenced on November 15, 2008. The contract expires December 31, 2018.

IMPA has entered into various monthly purchased power contracts with multiple counterparties to supplement the power and energy available to it from other resources. IMPA engages in both physical and financial transactions for capacity and energy.

Green Power

IMPA offers a green power rate to its members, for pass through to their retail customers. Under this rate, IMPA will obtain and provide green power for a small incremental cost over its base rate. As discussed above, IMPA entered into a contract for the purchase of wind energy. The expected annual output from this contract will provide approximately 2% of IMPA's its total energy requirements.

Net Metering Tariff

On January 28, 2009 the Board approved IMPA's net metering tariff. This tariff allows for the net metering of small renewable energy systems at retail customer locations. At this time, IMPA knows of only one net metering installation.

IMPA has been approached by customers wishing to install larger renewable systems that exceed the maximum size allowed under the net metering tariff. IMPA's preferred method of handling these large systems is to sign a contract to purchase the power as is done with the industrial customers referenced below. At this time, there are no larger renewable installations taking advantage of this offer.

Retail Customer-Owned Generation

IMPA has a contract with one commercial/industrial customer of an IMPA member to purchase excess generation from their onsite generation facilities. Under the current contract, the customer has been selling small amounts of energy to IMPA for approximately two and a half years.

With the exception of emergency back-up generators at some hospitals, factories and water treatment plants, IMPA knows of no other non-renewable retail customer generation in its members' service territories.

Demand-Side Resources

Existing demand-side resources consist of programs coordinated by IMPA as well as those implemented by its members. A discussion of existing programs is provided below.

IMPA Participation in the Statewide TPA CORE Program

IMPA has been an active participant in the state Demand Side Management Coordination Committee (DSMCC) since its inception in early 2010. Several members of IMPA's staff heavily participated in the development of the TPA and EM&V RFPs and actively participated in the vendor bid reviews and final vendor selection. At the same time, IMPA has received board approval for all of IMPA to participate in the CORE program even though less than ten members are required to do so by the IURC.

IMPA Commercial and Industrial Prescriptive Rebate Incentive Program

After the planned January 1, 2011 start up of the statewide Core program was significantly delayed, IMPA Board's approved the launch of an IMPA Commercial and Industrial rebate program modeled after the proposed statewide Core program. This was done to provide easy program transition when the statewide program kicks off. IMPA designed the program and it was launched on March 1, 2011. This rebate program is managed in-house with only limited outside vendor support and expense.

Energy Efficiency and Conservation Education

IMPA has long promoted energy efficiency and conservation in its member communities. IMPA includes such information, developed both from public and internal sources, in the *Municipal Power News,* a publication which IMPA mails to members' customers' homes and businesses three or four times each year. The Agency also provides literature containing conservation and efficiency tips to member communities for distribution in their local utility offices or events.

Each issue of *Municipal Power News* includes a small energy efficiency quiz. Customers may enter their answers in a drawing at IMPA. Correct responders are mailed a small energy efficiency kit consisting of CFLs, weather stripping, outlet insulators and energy savings tips. IMPA has distributed approximately 700 of these kits through this and other delivery mechanisms.

IMPA has updated its website at www.impa.com to include energy efficiency, conservation and safety information for consumers as well as provided the APOGEE online energy audit application, as discussed below. These new web pages include conservation tips, renewable and environmental information, and safety facts, as well as links to energy websites like *Energy Star®* and the U.S. Department of Energy.

When requested, IMPA staff also assists its members in their (and their retail customers') explorations of greater energy efficiency and improved uses of electricity. For example, IMPA has provided walk-through energy audits and recommendations for power factor improvements to individual industrial customers.

Compact Fluorescent Light (CFL) Rebate Program

In the fall of 2008, IMPA began distributing CFL rebates in its communities. Working in conjunction with General Electric, IMPA distributed coupons worth $1 off any package of CFL bulbs. With the planned Statewide TPA implementation date of January 1, 2011, this program ended in 2010 with the last distribution of coupons occurring in the summer of 2010.

Home Energy Suite™

In March of 2009 IMPA contracted with APOGEE Interactive for the online *Home Energy Suite™*. This is an online application that allows customers to input information regarding their home and appliances and determine approximate consumption and costs of electricity. The application features many useful pages that allow consumers to see which appliances are costing them the most money, where they can save money, potential savings from higher efficiency appliances, etc. The site is hosted on IMPA's website, with most member communities offering links from their websites (some smaller towns do not have utility websites and high speed internet access is not available in all IMPA communities). The site is also advertised in IMPA newsletters. Since March 2009, the site has received over 300,000 hits.

Demand Response

On December 10, 2010 IMPA's board approved Demand Response tariffs in order to utilize demand response programs offered under the MISO and PJM tariffs. At this time, no customers have signed up for the program.

Member Programs

IMPA's members have implemented a variety of programs and projects tailored to their individual systems to reduce peak demand and encourage efficient energy utilization. Most of these programs are rate or customer service related. Examples include coincident peak rates, off-peak rates, power factor improvement assistance, load signals to customer-owned peak reduction or energy management systems, AMI/AMR and streetlight replacement with more efficient lamps.

TRANSMISSION

A major portion of IMPA's load is connected to the JTS that is jointly owned by DEI, IMPA and WVPA. Pursuant to the terms of the Transmission and Local Facilities Ownership, Operation and Maintenance Agreement (the "T&LF Agreement") and the License Agreement, IMPA dedicated and licensed the use of its portion of the JTS to itself, DEI and WVPA. DEI and WVPA similarly dedicated and licensed the use of their facilities to IMPA. The T&LF Agreement provides mechanisms for the owners to maintain proportionate ownership shares and to share proportionately in the operating costs and revenues from the JTS.

DEI is responsible for the operation and maintenance of the JTS. In addition, DEI performs all load and power flow studies for the JTS and recommends improvements or expansions to the JTS Planning Committee for its approval. DEI files the FERC Form 715 for the JTS. A copy of the most recent Form 715 is included on the confidential CD accompanying this report.

IMPA is a member of MISO, as a Transmission Owner. DEI (Indiana) and WVPA are also Transmission Owner members of MISO. The higher voltage facilities of the JTS are under the operational and planning jurisdiction of MISO. The initial purpose of MISO was to monitor and control the electric transmission system for its transmission owner members in a manner that provides all customers with open access to transmission without discrimination and ensures safe, reliable, and efficient operation for the benefit of all consumers. Although MISO has since expanded its mission to include the operation of an energy market, it also continues to fulfill this initial purpose. Approximately 67% of IMPA's load is connected to delivery points on MISO-controlled transmission lines of the JTS, NIPSCO and Vectren. The remaining portion of its members' load is connected to delivery points on the AEP and Duke-OH (1/1/2012) transmission systems, located in the PJM footprint.

SUMMARY OF 2011 LOADS AND RESOURCES

Table 4 shows IMPA's actual 2011 loads, resources and resulting actual reserve margin. Because IMPA supplies power from its own and its members' generating capacity as well as firm power purchases (wherein the supplier maintains adequate reserves to assure a reliable power supply), IMPA's available reserve margins are not directly comparable to traditional reserve margins. In general, IMPA plans for reserves on that portion of its load that is served with non-firm resources. Reserves are not required on firm resources, for which the supplier maintains reserves. Firm resources include Gibson 5, as well as purchases of firm power from AEP and DEI. With the record heat wave in the summer of 2011, IMPA set an all time peak demand record on July 21, 2011 of 1,226[1] MW.

1 From an operational perspective, 1,226 MW was an all time peak demand for IMPA. However, factoring in current members who were not members at the time, IMPA's all time peak would be approximately 1,250 MW in the summer of 2007.

Indiana Municipal Power Agency
Loads and Resources at 2011 Peak

2011 Peak Demand	1,226
Available Reserves	61
Total Requirements	1,287
Gibson #5	156
TC #1	66
TC #2	96
ACTs	138
Grgtwn CTs	145
RCTS	67
WWVS	90
Peru	30
Jasper	-
Renss	18
Purchased Power	481
Total Resources	1,287

Available Reserves represents the difference between IMPA's resources and its actual peak.

Table 5 - 2011 Loads and Resources

PLANNED RESOURCES

As discussed previously, in its Order in Cause No. 42455, the IURC authorized IMPA's participation in three new coal-fired generating projects, as well as the purchase of the existing Georgetown Combustion Turbines. The Georgetown units were purchased in 2004 and Trimble County Unit 2 was placed in service in January, 2011. The following paragraphs describe the remaining projects.

Prairie State Project

The Prairie State Project consists of the Prairie State Energy Campus (Prairie State), related electric transmission system facilities, the Lively Grove mine and the Jordan Grove coal combustion waste disposal facility (CCW). IMPA is part of a consortium known as the Prairie State Generating Company (PSGC) that is developing this project. IMPA has a 12.64% interest in the Prairie State Project.

Prairie State is in the southwest part of Washington County, Illinois, approximately 40 miles southeast of St. Louis, Missouri. The plant will include two steam-electric turbine generators totaling approximately 1,600 MW. The plant's two boilers will be supercritical, pulverized coal steam generators with low-NO_x burners, SCR's, dry electrostatic precipitators, wet flue gas desulfurization, and wet electrostatic precipitators. PSGC entered into an amended and restated fixed price contract with the Bechtel Power Corporation on July 21, 2010, to provide a fixed price and engineering, procurement, and construction services.

The Illinois Environmental Protection Agency (IEPA) issued the final construction air permit for the power plant on April 28, 2005. Several parties appealed this permit to the U.S. EPA Environmental Appeals Board. This Board upheld the permit. The interveners then appealed to the U.S. Court of Appeals for the Seventh Circuit, which held a hearing on May 31, 2007. On August 23, 2007, the Seventh Circuit issued its decision denying all allegations presented in the appeal. On October 1, 2007, the petitioners filed for a re-hearing of the air permit before the full U.S. Seventh Circuit Court of Appeals. On October 11, 2007, the Court denied the petitioners' request and the permit subsequently became final.

The IEPA issued a permit for the National Pollution Discharge Elimination System (NPDES) for the Prairie State on December 5, 2005. Several parties appealed this permit. PSGC and the petitioners reached settlements, and the appeals were withdrawn in March 2006.

PSGC issued the Final Notice to Proceed with construction of the project on October 1, 2007. This notice released and directed Bechtel, the engineering, procurement, and construction (EPC) contractor, to perform all necessary activities to construct and place both Prairie State units in commercial operation. The targeted contract commercial operation dates are December 2011 and August 2012. The Amended and Restated EPC contract contains penalties if commercial operation is achieved after specified dates.

The Prairie State Project also includes contiguous coal reserves owned by the project participants and the development of a mine portal to supply Illinois coal to the power plant. PSGC estimates the project-owned coal reserves will supply the coal required by the plant for approximately 30 years. Peabody Energy will provide PSGC with technical services during the construction and operation of the Lively Grove Mine which will produce 6.6 million tons per year. PSGC owns or controls 100% of the surface property around the mine portal. All permits required to construct and operate the portal have been issued. The mine is currently producing coal to build the coal pile at the power plant.

The Prairie State Project includes the necessary transmission facilities to allow the generation at the power plant to flow into the surrounding transmission system in a reliable manner. Ameren, through its operating utilities in Illinois and Missouri, owns and operates the surrounding transmission system facilities affected by Prairie State. On May 20, 2005, FERC approved an Interconnection Agreement under MISO's Open-Access Transmission Tariff for 1,500 MW from Prairie State. PSGC requested further analysis of an additional 150 MW of output from Prairie State. In October 2006, MISO issued a notice stating that up to 1,650 MW of the output of Prairie State is deliverable everywhere in the MISO geographical footprint. On May 16, 2007, Ameren received the final transmission Certificate of Public Necessity and Convenience from the Illinois Commerce Commission. Ameren placed the final required transmission line in service in December 2010.

Prairie State Units 1 and 2 are affected by the CSAPR. Both units will be considered new units under CSAPR and will be allocated allowances from Illinois' new unit set-aside pool. IMPA expects that the allowances allocated by the U.S. EPA for Prairie State Units 1 and 2 are sufficient to cover its emissions in Phase 1 for both NO_x and SO_2 and also in Phase 2 of the rule, if the units meet their expected emission rate targets on SO_2 allocation.

Solid waste from these mine-mouth bituminous coal fired units will consist of the following CCBs: fly ash, bottom ash, and gypsum from the SO2 scrubber. The solid, dry waste will be disposed at the Jordan Grove facility. This is a 1,100 acre site located near Marissa, IL. The CCB will be transported via Canadian National Railroad to this site, which was previously operated as a surface coal mine. The material will be disposed of under an Illinois Department of Natural Resources mining permit and an NPDES permit. PSGC will actively pursue alternative reuses of CCBs.

Hazardous waste generation at Prairie State is expected to be similar to Gibson Unit 5 and Trimble County. All hazardous wastes generated by Prairie State will be properly characterized prior to disposal at appropriately permitted disposal facilities. The specific disposal facility chosen for a given waste will depend on the nature of that particular waste.

Thoroughbred Project

As stated in other sections of this report, after many delays and legal challenges, Peabody Energy decided to cancel the Thoroughbred project.

PART III - LOAD FORECAST

As a basis for this integrated resource plan, IMPA developed a 20-year monthly projection of peak demands and annual energy requirements. This part describes the forecast methodology, forecast results, model performance, and alternate forecast methodologies.

FORECAST METHODOLOGY

In December 2010 IMPA purchased IBM's SPSS Predictive Analytics Software for generating its load forecasts using time series analysis. Causal time series models such as regression and ARIMA will incorporate data on influential factors to help predict future values of that data series. In such models, a relationship is modeled between a dependent variable, time, and a set of independent variables (other associated factors). The first task is to find the cause-and-effect relationship.

ARIMA stands for Auto Regressive Integrated Moving Average. An ARIMA model can have any component, or combination of components, at both the non-seasonal and seasonal levels. The name autoregressive implies that the series values from the past are used to predict the current series values. While the autoregressive component of an ARIMA model uses lagged values of the series values as predictors, the moving average component of the model uses lagged values of the model error as predictors. The integration component of the model provides a means of accounting for trend within a time series model.

The SPSS forecasting software was used to create monthly forecasts for each IMPA load zone for both coincident peak demand and energy requirements. The ARIMA method allows for the development of a mathematical equation that accounts for both a seasonal influence and an overall trend based on the data available.

DATA SOURCES

IMPA used 84 observations of monthly historical energy and demand requirements in developing all the forecast models, except for Blanchester which only had 48 observations available. These numbers were obtained from actual IMPA member billing data. To create a consistent historical database for developing the statistical models, additional demand and energy data for Argos, Huntingburg, Jasper and Straughn (part of NIPSCO, SIGECO and DEI load zones) were included for the period prior to their respective IMPA memberships.

Monthly historical heating and cooling degree-days (HDD and CDD) and daily maximum and minimum temperatures data were obtained, for the period 2003 through 2010, from the National Oceanic and Atmospheric Association—NOAA (www.noaa.gov). The mean temperature was calculated from the average of the daily maximum and minimum temperatures. The build-up temperature data, was calculated by the summation of the coincident peak date maximum temperature times 10/17, previous day maximum temperature times 5/17 and the second day back maximum temperature times 2/17. This variable had a greater statistical significance in the demand models than maximum temperature. Weather data was selected from three different weather stations in Indiana and one from Ohio for their proximity to IMPA's 54 member communities; the Indianapolis weather station for AEP and Duke IN, South Bend for NIPSCO, Evansville for SIGECO and Cincinnati for Blanchester.

Economic variables from the Bureau of Economic Analysis (www.bea.gov) used in the models include US Real Gross Domestic Product (GDP), Indiana real personal income and the Indiana unemployment rate. Average wholesale electric price was determined for each member from the actual historical IMPA power bills to the members aggregated by supply area and divided by the total energy purchased in that area. Both the GDP and the average electric price were deflated by the Consumer Price Index for all Midwest urban consumers.

MODEL DEVELOPMENT

Over the past several years, IMPA has generated forecasts for each individual member city and aggregated the member forecast by load zone. This year IMPA began forecasting just the five load zones on the same basis as power is dispatched and reported to MISO and PJM. Multiple models were created and the best fit models were chosen after careful attention was given to the statistics, growth rates and load factors, making sure all were within an acceptable range and reflect the historical data. Developing demand and energy forecast models for five zones allowed greater attention to statistics and model detail than could be done by forecasting fifty-four member cities individually.

Models were developed in the SPSS software with demand and energy as the dependent variables. Forecasts were obtained for each independent variable. Weather variables cannot be forecasted for more than a week or so with any level of accuracy, therefore, monthly averages of the historical monthly data were used. The weather data was normalized for each month using the past seven years, 2003 through 2010, and then this normalized weather was repeated annually from 2011 through 2031. The economic variables were projected using forecasted growth rates from the United States Congress Congressional Budget Office's (CBO) Budget and Economic Outlook: Fiscal Years 2011 to 2021 report (www.cbo.gov). For years 2022 through the 2031 the growth trend assumption for 2021 was continued.

For the demand model, the dependent variable was the load zone coincident peak demand (kW). The independent variables typically included temperature build-up during summer months, minimum monthly temperatures for the winter months, average monthly temperatures during the spring and fall shoulder months, and various economic variables. The temperature data was converted to Celsius so that the majority of the winter data was negative and produced a negative coefficient. As mentioned previously, the temperature build-up variable is composed of a weighted average of the temperature of the peak day plus the previous two days. The monthly temperatures were from the historical monthly coincident peak dates which were normalized for the forecast.

The dependent variable in the energy model was the sum of each load zone monthly energy requirements (kWh). The independent variables were CDD, HDD, and economic variables.

MODEL SELECTION

The SPSS software produced model fit parameters, residual errors and variable coefficients. The R-square, t-Statistics and coefficients were then evaluated to determine whether to keep or eliminate a model. The statistical validity of each forecast model was evaluated focusing on the R-square and error residuals of the models, the sign of each coefficient and the significance of each t-Statistic of the variables. For example, all weather variables should have a positive sign on the coefficient indicating that as the temperatures increase, the load increases. The one exception is minimum temperature for the winter months. In this case, the sign would be a negative reflecting an inverse relationship; as the temperatures decrease, the loads increase. All economic variables should have a positive sign as well, indicating as the economy grows, electricity use will increase. The exception here is the average electric price; the sign of the coefficient would be negative, because as the costs of electricity rises, usage should inversely decrease.

The t-Statistics of most variables were significant, minimum 2.0, the exception being the SIGECO area, which had experienced little load growth in the past few years. SIGECO's economic variables were slightly lower than the 2.0 minimum, 1.7 for GDP in the demand model and 1.1 for Real Personal Income in the energy model. The two economic variables influence the growth for the SIGECO forecast and are significant enough to still be considered.

The R-square statistic measures how successful the fit of the model is in explaining the variation of the data—a 1.0 R-square would explain 100% of the variation. In selecting models, higher R-squares with higher t-statistics were used to determine the best models for the forecast.

FORECAST DEVELOPMENT

Having input the monthly projections of the independent variables for 2011 to 2031, the SPSS software was used to compute the forecasts from the selected demand and energy models. For quick visual analysis of the load curves and growth rates, the SPSS software also generated a graph of the forecasted and backcasted data, which is fitted over the historical data. The SPSS software completed monthly demand and energy projections from 2011 to 2031 and backcasted from 2004 to 2010. The forecasted data that are output from the SPSS was then transferred into Microsoft Excel for further analysis. Using the forecasted energy and demand data, monthly and annual load factors and annual growth rates were calculated. The growth rates between demand and energy forecasts and the load factor trends for each control area were evaluated for consistency.

Only demand and energy projections with consistent growth rates and load factors were chosen for the forecasts. No adjustments were made for potential gain or loss of large customers. All the individual control area forecasts are aggregated to produce the IMPA forecast.

FORECAST RESULTS

The forecast of IMPA's expected peak demands and annual energy requirements is presented in Table-6. The resulting long-term average growth rate is just under 1% per year for both peak demand and total energy requirements.

Indiana Municipal Power Agency
2012 Load Forecast

	Base		High		Low	
	Peak Demand	Energy	Peak Demand	Energy	Peak Demand	Energy
Year	MW	MWh	MW	MWh	MW	MWh
2012	1,168	6,160,345	1,188	6,267,217	1,148	6,053,472
2013	1,182	6,222,363	1,211	6,373,504	1,153	6,071,222
2014	1,196	6,273,437	1,231	6,458,546	1,160	6,088,328
2015	1,212	6,327,716	1,253	6,541,462	1,171	6,113,970
2016	1,227	6,383,367	1,273	6,622,342	1,181	6,144,392
2017	1,238	6,438,547	1,288	6,700,331	1,188	6,176,763
2018	1,249	6,492,683	1,303	6,775,442	1,195	6,209,924
2019	1,260	6,547,066	1,318	6,849,348	1,201	6,244,784
2020	1,270	6,602,707	1,332	6,923,326	1,209	6,282,088
2021	1,281	6,659,634	1,346	6,997,596	1,216	6,321,673
2022	1,292	6,717,877	1,360	7,072,334	1,224	6,363,420
2023	1,304	6,777,463	1,375	7,147,681	1,232	6,407,245
2024	1,315	6,838,423	1,389	7,223,759	1,241	6,453,087
2025	1,327	6,900,788	1,404	7,300,670	1,250	6,500,906
2026	1,339	6,964,589	1,418	7,378,506	1,259	6,550,673
2027	1,351	7,029,859	1,433	7,457,351	1,269	6,602,368
2028	1,364	7,096,631	1,448	7,537,280	1,279	6,655,983
2029	1,376	7,164,940	1,464	7,618,363	1,289	6,711,516
2030	1,390	7,234,820	1,479	7,700,668	1,300	6,768,972
2031	1,403	7,304,947	1,494	7,782,897	1,311	6,826,997
CAGR - %	0.97%	0.90%	1.21%	1.15%	0.70%	0.63%

Table 6 - 2012 Load Forecast

The historical data reflect the impacts of IMPA and its members' past DSM programs. Since the effects of the DSM programs are relatively small in comparison to the magnitude of the loads, IMPA made no specific adjustment to its base forecast to reflect changes in the future.

Future changes will include the effects of increased appliance energy efficiencies mandated by the Energy Policy Act of 2005. Pursuant to this Act, the U.S. Department of Energy issued a five-year schedule for setting new energy efficiency standards for appliances[2]. Examples of new appliances to be covered in the standards include ceiling fan light kits, fluorescent lamp ballasts, dishwashers, ranges and ovens, dehumidifiers and commercial clothes washers. The Act also increased the required efficiencies of other appliances such as air conditioners and furnaces. Cumulatively, these new efficiency standards will cause reductions in consumer energy use.

Other potential impacts not quantified in IMPA's 2012 Load Forecast are the higher prices that may result from new environmental requirements (e.g., carbon sequestration) and/or from the higher costs of increasing the quantity of renewable energy resources in IMPA's power supply portfolio. Another impact not quantified is the new energy efficiency and demand-response programs that might result from the evaluations identified in IMPA's Short-Term Action Plan. (See Part VI.)

FORECAST UNCERTAINTY

This section includes assumptions, methods, and the manner in which uncertainties are treated in the forecasts of aggregated peak demands and energy requirements. Three cases/scenarios were developed as described herein.

For the first method in addressing forecast uncertainty, IMPA developed forecasts using confidence intervals. A confidence interval addresses the issue of how good of a fit the forecast model is because the intervals provide a range of values, in essence a measure of the precision of the estimate. The confidence levels here are 95%, meaning that the resulting intervals would bracket the true data range in approximately 95% of the cases. A two-sided confidence interval is used which brackets the data from above and below. For each load zone there is an upper and lower 95% confidence limit forecast for demand and energy. This percentage represents approximately two standard deviations of the difference between the calculated values and the actual values experienced by IMPA over the historical period. Statistically, two times the standard deviation represents approximately a 95% chance of occurrence. See the high and low columns in Table 6 and Figures 3 and 4 for a graphical representation.

2 "Implementation Report: Energy Conservation Standards Activities; U.S. Department of Energy, February 2007.

Demand Forecast w/ 95% C.I.

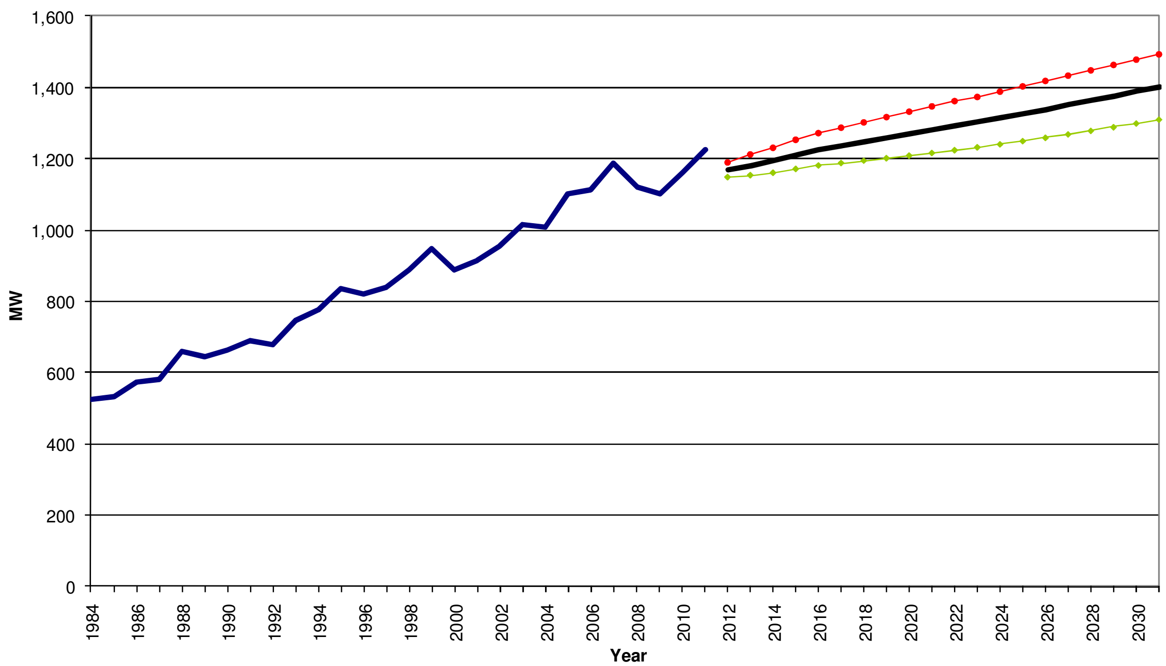

Figure 3 - Demand Forecast Range

Energy Forecast w/ 95% CI

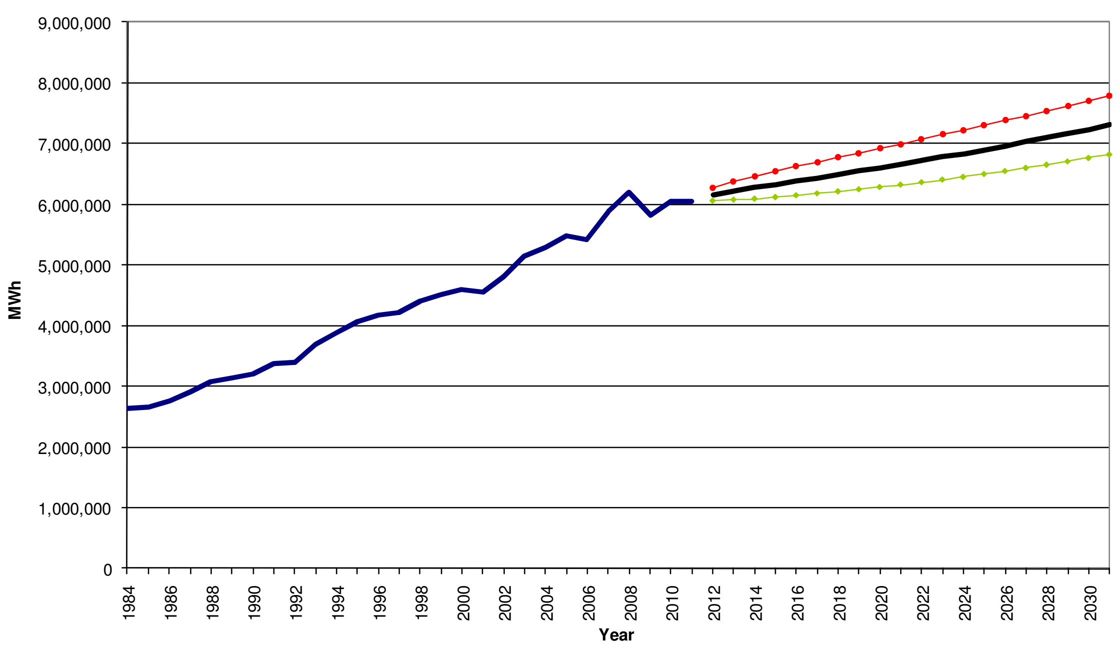

Figure 4 - Energy Forecast Range

The second forecast variation dealt with uncertainty in the economy. To develop the high and low economic cases, low and high scenarios of the CBO economic variables described earlier were used. The high growth case increased the annual growth rate in demand and energy by .22% and .18% respectively. The low growth case lowered the growth rates by .21% and .17%.

Further addressing forecast uncertainty, IMPA evaluated the uncertainty associated with weather variations. To anticipate the magnitude of possible load variation under weather extremes, two "extreme weather" peak demand forecast scenarios were developed for each area. The baseline forecast for normal peak demand and energy requirements are based on average weather conditions. Extreme weather demand scenarios are based on the most extreme weather which occurred during each month over the historical data period—2003 to 2010. The extreme weather scenario produces a peak demand which is 3.7% higher than the normal weather peak in 2012. A similar method was used for mild weather. The mild weather scenario reduced the peak demand 4.1% from the forecasted peak demand.

Details of the forecasting models and model results are shown in Appendix C.

MODEL PERFORMANCE

IMPA has prepared load forecasts every two or three years since 1983. The last three forecasts, along with IMPA's 2012 forecasts are shown on Figures 5 and 6 on the following page.

Historic and Forecasted Peak Demand

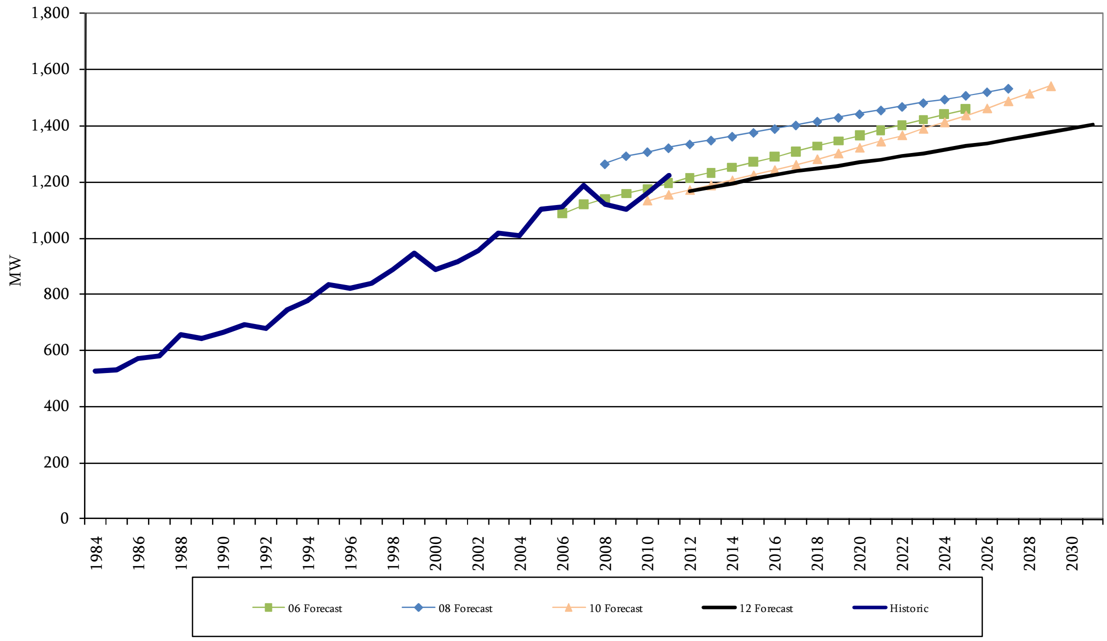

Figure 5 - Demand Forecast Comparisons

Historic and Forecasted Energy Requirements

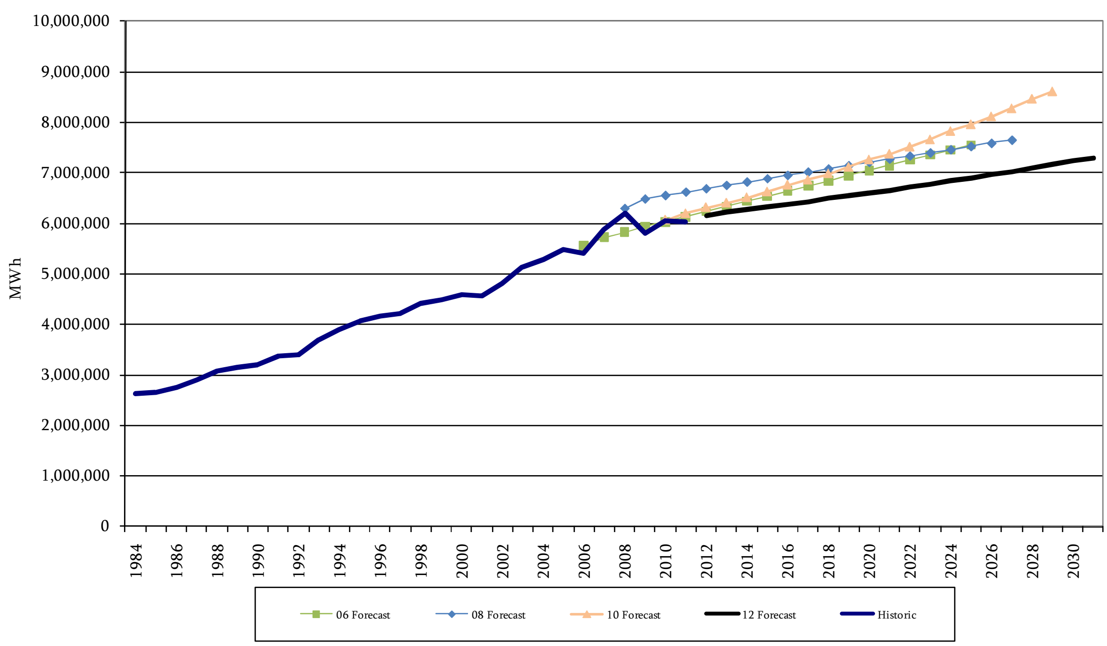

Figure 6 - Energy Forecast Comparisons

ALTERNATE FORECAST METHODOLOGIES

IMPA has not generated forecasts by rate classification or sector. Since IMPA does not sell directly to retail customers, it does not have direct access to customer billing units. To generate a customer sector forecast, IMPA would need to collect several years of annual historical billing summary data from each of its fifty-four members. In addition, the criteria determining member rate classes can change over time, and it would be nearly impossible to ensure consistent sector data back through the historical period. Finally, different members identify sectors (or classes) of customers differently. For example, two members may have a large power rate classification. Under this classification, one member's largest customer may be a 10 MW industry whereas the other may be a single 200 kW customer. For these reasons, sector forecasting would be very difficult for IMPA.

Another forecast methodology is end-use. The data requirements for an end-use model are extensive. They include detailed information on appliance saturations and usage patterns in the residential sector, data on building and business types in the commercial sector and detailed equipment inventories, lighting types, and square footage area in the industrial sector. IMPA's member communities are not uniform, they contain various ages of homes and businesses. The age of the residents and vintage of the houses can have a significant impact on the saturation of various appliances. To collect the proper saturation data at the member level, IMPA would need to collect a valid sample of each member's customers. A valid sample is approximately 300 customers whether the community is large or small. Additionally, since the response rate to surveys is typically 30% to 35%, IMPA would need to survey at least 1,000 customers in each community. This requirement makes end-use sampling unreasonable, considering that IMPA would need to sample 25% to 30% of all the customers its members serve. Most investor-owned utilities, while serving thousands more customers, would only need to sample about 1,000 customers to ensure a valid sample. Therefore, IMPA cannot realistically utilize this type of a forecast model.

FUTURE IMPACTS OF ENERGY EFFICIENCY AND CONSERVATION PROGRAMS

The base forecasts included in this report do not include projections of the impacts of Demand-Side Management and/or Energy Efficiency and Conservation Programs. At the time of the preparation of the load forecasts, IMPA has few measurable programs in place. IMPA plans to participate in the statewide programs which are currently being developed and anticipates that future forecasts will include the impacts of participation in such programs.

PART IV - DESCRIPTION OF RESOURCE OPTIONS

Based on IMPA's 2012 Load Forecast and its current and planned portfolio of resources, IMPA will need additional resources in the next 5-10 years. This Part summarizes potential resources that IMPA is considering to ensure it can continue to serve its members reliably and economically.

SUPPLY-SIDE OPTIONS

Potential supply-side options include upgrades to existing generating capacity, construction or acquisition of additional generating capacity, and entering into additional contracts for purchased power. New IMPA-owned capacity could include generating units constructed and owned by IMPA or participation in the ownership of either existing or new generating units with third parties, preferably in Indiana. Purchased power could include purchases from other utilities, independent power producers or power marketers. While IMPA is well situated to construct, own and operate smaller generating facilities such as peaking plants, landfill gas plants, and possibly even wind turbine plants, as a practical matter, IMPA would expect to participate with others in the development of any new larger resources. Joint development of resources would enable IMPA to enjoy the economies of scale of a larger facility and at the same time adhere to the principle of diversification.

Additional Upgrades or Retirements of Existing Capacity

IMPA's existing generating capacity consists of its ownership interests in Gibson 5, Trimble County 1&2, seven wholly-owned combustion turbines and member generating capacity that is dedicated to IMPA for its use. IMPA is not aware of any potential upgrades to Gibson 5 or Trimble County 1&2 that could increase their output capability. Each of IMPA's generating members has reviewed its generating capacity to examine the feasibility of plant upgrades and improvements. All feasible upgrades have been implemented, and IMPA is not aware of any other potential upgrades to this capacity.

For purposes of this IRP, IMPA assumes the City of Richmond will retire Whitewater Valley Unit 1 in 2015 and Unit 2 in 2025. The member generation at Peru, Jasper and Rensselaer (diesels) is assumed to retire at the end of 2015. Crawfordsville's contract with IMPA was terminated in 2011. Actual retirement dates will vary as none of the plants are specifically slated for retirement at this time. Recently, Crawfordsville, Jasper, Peru and Richmond have been investigating selling and/or converting the coal fired facilities to renewable energy projects. At this time, there are no definitive plans for the conversions. As such, the plan shown in next section could change depending on actual retirement dates or plant conversions.

New Resources

IMPA is in the evaluation stage concerning additional resources. The resources considered in this study include:

- Coal-fired steam generation (100 MW from a 750 MW unit)
- Integrated Gasification Combined Cycle (IGCC) w/ Carbon Capture and Sequestration (CCS) (100 MW from a 550 MW unit)
- Standard combined cycle (CC) units (100 MW from a 530 MW unit)
- Gas-fired combustion turbines (CT) (75 MW)
- Gas-fired high efficiency internal combustion (IC) units (10 MW units in multi unit sets)
- Wind or other renewable sources (50 MW)

Given IMPA's existing fleet of resources, baseload generation will not needed by IMPA for some time. The likely additions to the portfolio will be gas fired intermediate and/or peaking capacity and this was the focus of the study.

During IMPA's consideration of supply-side resources, it assumes any new resource would comply with the applicable environmental requirements. Such requirements specify that the potential resource undergo an environmental review prior to the beginning of construction and that the potential resource comply with any environmental constraints. When IMPA petitions the IURC for approval relating to new supply-side resource, IMPA would include information concerning these environmental matters, including the results of any due diligence investigations.

Power Purchases

Although IMPA has not identified any specific long-term firm purchased power options at this time, it will continue to consider such options as they may become available in the future.

Energy Markets

IMPA participates in both the MISO and PJM markets for balancing capacity and short-term purchases/sales. However, IMPA does not believe it is prudent to rely on these short term capacity and energy markets to meet its long-term requirements.

For purposes of this IRP, IMPA limits the installation of new resources to those needed to serve its own loads. Although IMPA will sell short–term surplus capacity and energy through the organized markets, IMPA does not believe it is prudent to install generation for the purpose of speculative sales.

DEMAND-SIDE OPTIONS

With the advent of new environmental regulations and the longer term potential for CO_2 legislation IMPA's Board has decided to actively pursue energy efficiency and conservation much more aggressively than it has in the past. As part of the board's strategic plan approved in 2009, IMPA will target a 10% reduction in projected demand and energy requirements by 2020. For this analysis, after reaching the goal in 2020, the program slows down over the following five years.

At this time, the Statewide Core programs will be the primary vehicle for energy efficiency savings and the majority of the budgeted expenditures are for those programs. The following sections highlight probable programs.

Statewide Third Party Administrator (TPA) Core programs.

The statewide TPA will provide five Core programs through this statewide initiative. The programs are:

- C&I Prescriptive Rebates
- Residential Home Lighting
- Low Income Weatherization
- Home Energy Audits
- School Audits and Education

Approximately 90% of IMPA's Core program goals will come from the C&I and Residential lighting programs.

In addition to the CORE programs discussed above, IMPA will need to offer an expanded menu of programs in order to meet its long term goal. These "core-plus" programs to be investigated include:

Commercial and Industrial Customized Audits

This program would provide member commercial and industrial loads with assistance in improving the energy efficiency of their installations. Such efforts could include, lighting retrofits, day lighting, high efficiency pumps/motors as well as variable speed drives. The program would be customer specific based on the audit performed by IMPA or member representatives.

High Efficiency Residential Appliances

This program is envisioned to be a rebate program for the purchase of high efficiency appliances that exceed the minimum federal standards. Initial program targets would likely be *Energy Star*® rated home appliances such as washers, dryers, refrigerators and ranges. Programmable thermostats would also be a component of this program.

HVAC and Home Envelope

This program would seek to incentivize the early retirement of low efficiency HVAC equipment nearing the end of its useful life as well as encourage and promote home envelope improvement measures.

Refrigerator Turn In

This program would incentivize customers to turn in inefficient second refrigerators.

New Construction

This program would encourage the installation high efficiency lighting, HVAC, appliances and building envelope at the time of new building construction. This program may apply to both residential and commercial construction.

Commercial and Industrial Demand Response

Utilize the previously mentioned Demand Response tariff to provide capacity to meet RTO planning needs.

The following figure shows the annual energy efficiency energy savings split between Core and Core-plus programming. The table maintains the original five Core programs through the future. However, it is likely that as the three year TPA contracts roll forward into future years, more programs will be added to that contract.

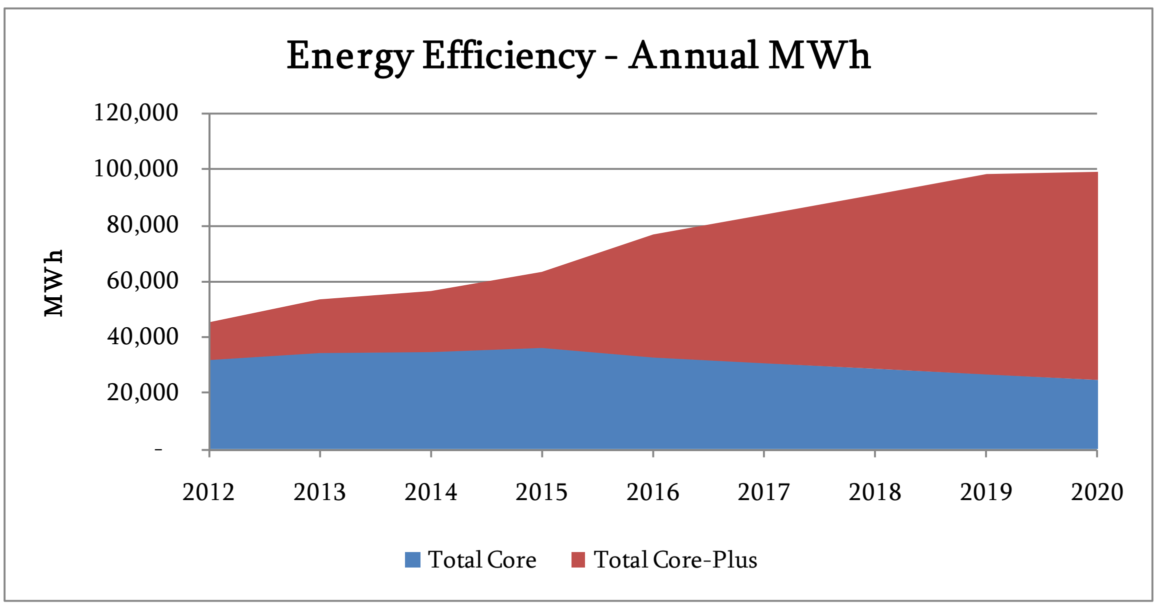

Figure 7 - Energy Efficiency - Annual MWh

Cumulatively, the figures shown above reduce IMPA's 2020 energy requirements by over 650,000 MWh. Given IMPA's long term goal to reach this level of energy efficiency, the energy reductions shown above are included in the plans utilizing the energy efficiency targets. A 15 year budget of energy efficiency program costs is also included; however, no specific plans are in place except for the Core program participation. Economic conditions and customer willingness to adopt energy efficiency programming will determine how much of the targeted savings will be achieved.

TRANSMISSION

As noted previously, IMPA is a member of MISO as a Transmission Owner within the DEI area and is a Transmission Dependent Utility (TDU) within the NIPSCO and Vectren areas of MISO. IMPA is also a TDU receiving transmission service from PJM for its loads in that footprint.

MISO performs all of the transmission system planning for the facilities under its operational control, which includes most of the JTS. In the DEI local balancing area, DEI performs any additional transmission system planning functions on behalf of the three owners of the JTS (see Part II, Appendix D and the confidential FERC Form 715 on the CD accompanying this IRP). IMPA participates in the joint owners' Planning Committee, which reviews major system expansions planned by DEI. IMPA assists its members where needed in determining when new or upgraded delivery points are required and coordinates any studies, analysis or upgrades with other utilities.

PART V - EVALUATION OF RESOURCE OPTIONS

The evaluation of resource options is a multifaceted process. Certain aspects of this evaluation process are ongoing. IMPA is continuously in pursuit of resources that enable it to continue providing its members with low-cost, reliable power produced in an environmentally-responsible manner. The following paragraphs present various aspects of IMPA's considerations.

DIVERSITY

Presently, IMPA has a diverse set of power supply resources to serve its members with low-cost, reliable power and energy. IMPA's resources are diverse in terms of size, fuel type and source, geographic location, type of resource, and vintage. This diversity reduces IMPA's exposure to such risks as forced outages, catastrophic equipment failures, LMPs, strikes and unexpected increases in fuel costs. IMPA has also taken advantage of opportunities to purchase long-term, cost-based power in lieu of constructing new generation. IMPA expects to continue to be an active participant in the competitive wholesale energy markets for short-term purchases and sales, and to consider longer-term purchased power opportunities in lieu of new generation when it is economical to do so, taking into consideration reliability, uncertainty, risk, environmental impacts and other factors.

IMPA desires to maintain the diversity in its power supply resources as it continually investigates and selects from the various alternatives available from time to time. IMPA also desires to maintain its ability to respond to changes in its members' power and energy requirements and to the rapidly changing conditions of the electric utility industry.

TERM

For purposes of this IRP, IMPA limits its consideration to long-term power supply resource options. While IMPA sometimes purchases shorter-term resources for a variety of reasons, IMPA does not consider a series of short-term purchases as an appropriate or reliable substitute for the long-term resources.

TECHNOLOGY

The evaluation of resource options involves an assessment of the resource's technology (*e.g.*, mechanical, electrical and environmental attributes) and long-term economic benefits. In addition, IMPA reviews the potential impact on the short-term and long-term rates to its members. Today's electric utility market also requires an assessment of the impact that a resource option (and/or the counterparties, if any) may have on IMPA's creditworthiness and financial strength.

IMPA's members have a long history of retail rates that are lower on average than those of other utilities whose retail rates are regulated, and IMPA is committed to helping its members retain this advantage. To that end, IMPA requires that any resource provide both long-term economic benefits and a cost structure that supports IMPA's stable wholesale rates to its members.

ECONOMIC ANALYSIS

IMPA utilizes a traditional style reserve margin calculation for expansion modeling. For this IRP, the RFC recommendation of 15.5% was used. IMPA uses a general inflation rate of 2.5% and a discount rate of 6%.

IMPA utilizes the MIDAS® system by Ventyx for long term production cost modeling and financial results. MIDAS® uses several modules to construct the financial simulation. Zonal market capacity and energy price projections are determined using Horizons Interactive. The capacity expansion module (CAPEX) performs a mixed integer capacity expansion plan. Finally, MIDAS Gold® performs a full dispatch of the portfolio and captures all aspects of IMPA's revenue requirements. IMPA also uses MIDAS® for such items as stochastic hedging analysis, long term financial studies and bond rating agency presentations. IMPA's modeling system is more fully discussed in Appendix E.

AVOIDED COSTS

IMPA's avoided costs are determined by calculating the marginal cost of serving the next increment of load. Avoided costs can be determined for capacity, energy and RTO transmission expenses based on current constructs utilized in the RTOs. The following paragraphs describe the methodology used to determine the avoided costs. The IMPA avoided costs values are considered proprietary and confidential information and are included with the other confidential information filed with this report.

Avoided Capacity Costs

In the MISO and PJM markets, the next incremental MW of capacity will cost the bilateral price of market capacity (MISO) or the base residual auction reliability pricing model (RPM) price (PJM). In the PJM RPM construct, the cost of a simple cycle combustion turbine is used as the basis for the RPM auctions although the actual auction price is based on many other factors, including load forecasts, PJM reserve requirements, demand response participation and market participant behavior. Given the frequency of change in the capacity market constructs, a long term projection of the PJM RPM prices or the MISO bilateral market price is not practical. IMPA's avoided cost is calculated using the same values for the simple cycle CT used in the expansion plan. The annual carrying charge for a CT is calculated along with projected fixed operation and maintenance expenses to determine a long term avoided capacity cost projection.

Avoided Energy Costs

By definition, in an LMP based RTO energy market the marginal cost of serving the next increment of load is the LMP. Therefore, IMPA's avoided energy cost is the projected market price of power.

Avoided Transmission Capacity Costs

As in energy, IMPA's avoided cost of transmission is based on the Open Access Tariff cost therein, or the incremental price of transmission services received from either PJM or MISO.

SCENARIOS

Three basic scenarios are presented in this analysis. The table below highlights the key factors in each scenario.

	Plan 01	Plan 02	Plan 03	Comments
EE	X			Targets 10% reduction in energy requirements by 2020
Renewable	X	X		Targets 10% Renewable energy by 2020
Gib 5 CSAPR $	X	X	X	Gibson 5 Capital Expenses to comply with CSAPR

Table 7 - Scenarios

The energy efficiency cases assume that IMPA's goal of 10% cumulative energy efficiency is reached by 2020. The figures below show IMPA's demand and energy forecast with and without the energy efficiency targets.

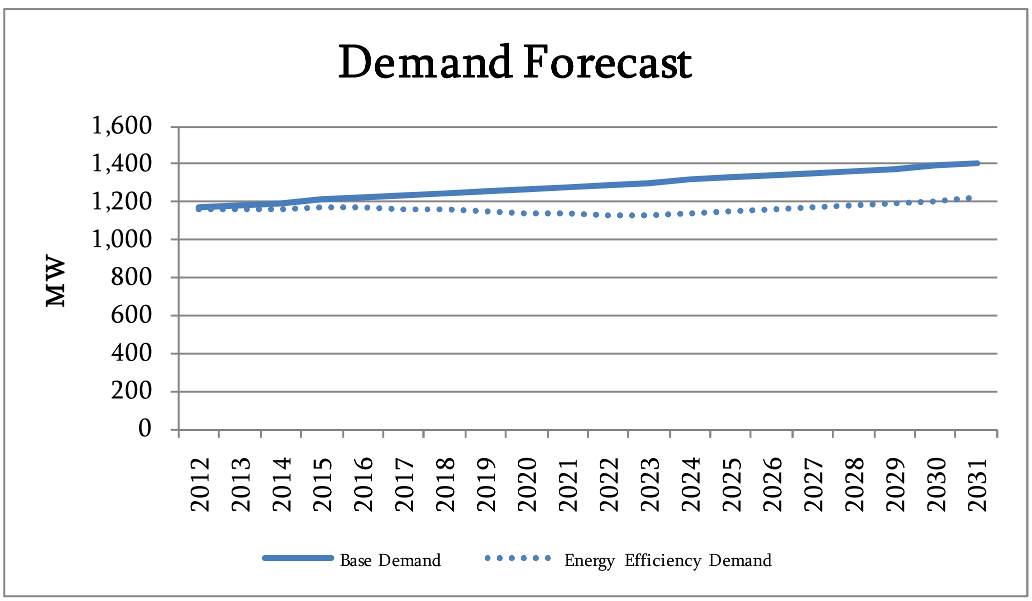

Figure 8 - Demand Forecast with Energy Efficiency

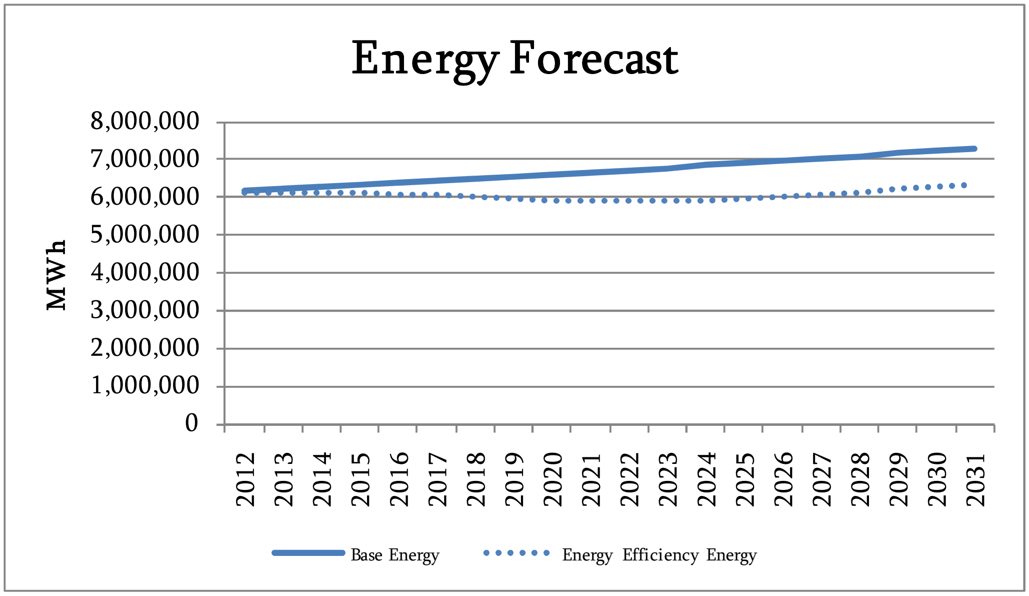

Figure 9 - Energy Forecast with Energy Efficiency

RESULTS

The following chart highlights the relative net present value (NPV) of revenue requirements for the three scenarios. As can be seen the energy efficiency scenario produces a far lower revenue requirement than the other scenarios. Plan 01's NPV is approximately 5.2% lower than Plan 03. From an NPV perspective Plan 02, which also includes a voluntary renewable target for IMPA, is more expensive than the plan without a renewable target, Plan 03. This is due to the fact that the wind resources are priced higher than market energy and because the wind resources add minimal capacity value. Acquisition of landfill gas or solar renewable resources could help mitigate the capacity issue.

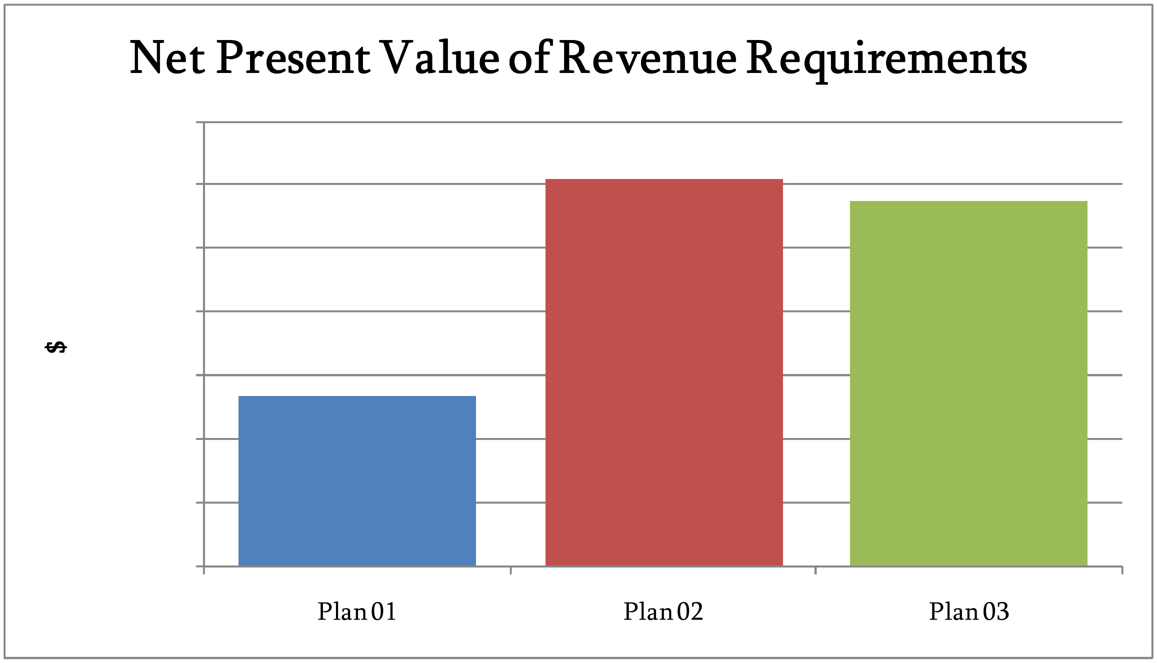

Figure 10 - NPV of Revenue Requirements

As stated earlier, IMPA's primary capacity need going forward will be for intermediate and peaking type resources. The energy efficiency scenario requires IMPA to acquire additional capacity in the future. Table 8 shows the capacity expansion plan for the next 20 years.

2011 IRP - Resource Additions/Deductions

Year	MW	Resource
2012		
2013		
2014		
2015	(23)	G5 Reserve/Back-Up PPA Expiration
2016	(90)	Member Gen Retirements
	75	New Gas
2017	(50)	Duke CB PPA Expiration
	75	New Gas
	50	Wind/Renew
2018	(50)	Market Capacity PPA Expiration
	(50)	Wind PPA Expiration
	50	Wind/Renew
2019	50	Wind/Renew
2020	50	Wind/Renew
2021		
2022		
2023		
2024		
2025		
2026	(65)	Member Gen Retirements
	150	New Gas
2027		
2028	50	Wind/Renew
2029		
2030		
2031		

Table 8 - Expansion Plan

With the energy efficiency programs in Plan 01, IMPA primarily adds new resources to make up for capacity that is lost due to retirements and contract expirations. Only a fraction of the added capacity is required to meet additional load as the 20 year load is relatively stable due to the large energy efficiency reductions. In the scenarios without energy efficiency, IMPA would need to install approximately 200 MW more capacity by 2031 in order to meet the additional load and reserve requirements.

Because of IMPA's preference to participate in generation projects jointly with other utilities in order to achieve economies of scale and diversity of resources, the availability and timing of the resources shown in these plans is dependent on the availability of opportunities to participate with other utilities in the development of such resources.

Although this study has focused on wind generation for renewable sources IMPA is also exploring other renewable generation options, such as generation from solar, biomass or landfill gas, which could substitute for or supplement the wind generation. Additionally, active customer participation in IMPA's net metering tariff would result in more renewable energy on IMPA's system.

SENSITIVITY ANALYSES

IMPA tested its plan(s) with the following sensitivity analyses. In each case, the plans were run with the following changes made in base assumptions:

- **Low Commodity Prices.** In this sensitivity, alternate natural gas prices were used to generate market power prices. The underlying assumption is the low gas price forecast from the US Energy Information Administration (EIA). This gas assumption reflects a higher percentage of shale gas available than in the EIA base case. As expected, the results of this sensitivity vary proportionally with the exposure the scenario has to market prices. Since Plan01 has the least market exposure, the percentage impact on the revenue requirement is the lowest of the three scenarios. Conversely, the sensitivity impacts Plan03 the most. The results of this sensitivity are graphically shown below.

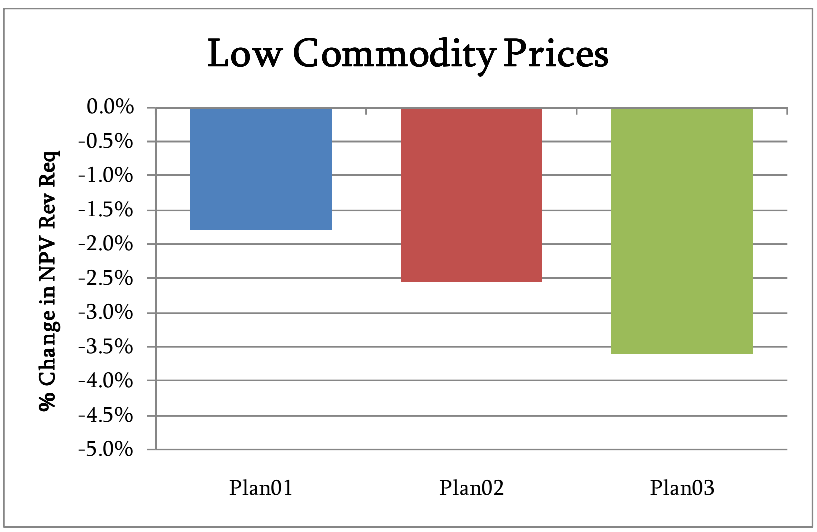

Figure 11 - Low Commodity Price Sensitivity

- **High Commodity Prices.** In this sensitivity, higher natural gas prices were used to generate alternate market power prices. The underlying assumption is the high gas price forecast from EIA which assumes a much lower amount shale gas available than in the base case. The results of this sensitivity are shown below. Once again, the results of this sensitivity vary proportionally with the exposure the scenario has to market prices. Since Plan01 has the least market exposure, the percentage impact on the revenue requirements is the lowest of the three scenarios.

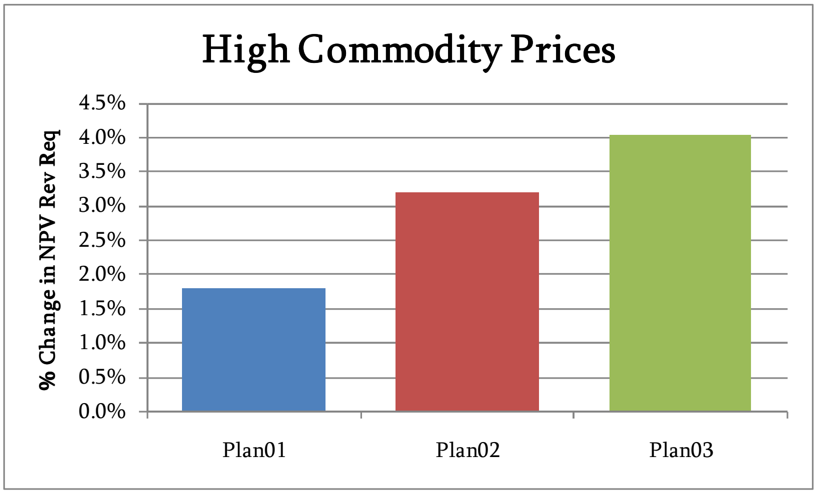

Figure 12 - High Commodity Price Sensitivity

- **CO2.** In this sensitivity, CO2 cap and trade legislation is enacted in 2015. New market price forecasts were run to reflect the increased market prices associated with the legislation. The results of this sensitivity show that carbon legislation would significantly impact IMPA's cost to serve its membership in any scenario. Again, Plan01, utilizing energy efficiency and renewable energy is the least impacted.

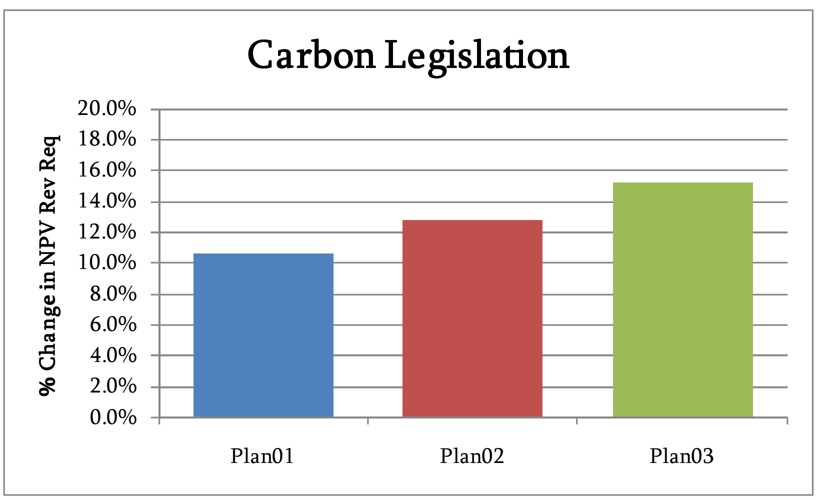

Figure 13 - Carbon Legislation Sensitivity

PART VI - SHORT TERM ACTION PLAN

IMPA proposes the following actions over the next 24 months.

For Supply-Side Programs:

- Complete the development of the Prairie State Project.
- Continue investigating options that may lead to IMPA's purchasing power from, obtaining an ownership interest in or constructing other resources to serve its need for future capacity and energy in PJM and MISO.
- Investigate and seek out renewable energy resources (wind, solar, biomass, and landfill gas generators).
- Continue to evaluate available purchased power contracts to optimize their utilization given IMPA's loads and existing resources.
- Continue to seek ways to better utilize IMPA-owned resources to minimize costs.

For Demand-Side Programs:

- Actively participate in the DSMCC's Statewide Third Party Administrator Core Programs
- Analyze and evaluate the results of the 2012-2013 Statewide Core program participation to determine next steps
- Investigate and Implement additional Energy Efficiency programs such as
    - Custom Commercial and Industrial Audits
    - Residential Appliance Rebates
    - HVAC and Home Envelope
    - Refrigerator Turn-in
    - Commercial and Industrial Demand Response
- Continue the enhancements to IMPA's web site to include additional energy efficiency, conservation and safety information for retail consumers
- Continue to support IMPA members' independent investigation and implementation of energy efficiency measures that are unique to their systems and facilitate the transfer of knowledge and lessons learned among members.
- Continue to offer members educational materials such as bill stuffers, brochures and other media that explain and encourage energy efficiency and electrical safety.

APPENDIX

The following items are included on the public CD provided with this report.

A. Hourly Loads
    a. EEI Format
    b. Form 714 Format
B. Load Curves
    a. Annual LDC
    b. Monthly LDC
    c. Typical Weeks (Summer/Winter)
    d. Typical Weekdays (Summer/Winter)
    e. Typical Weekends (Summer/Winter)
    f. Actual Peak Days (Summer/Winter)
C. Load Forecast
    a. IMPA Total
    b. AEP zone
    c. Duke-OH zone
    d. Duke-IN zone
    e. NIPSCO zone
    f. Vectren zone
    g. Alternate Forecasts Scenarios
D. Statement on Annual Transmission and Planning Evaluation Report – 715
E. IMPA Modeling System Overview
F. 2011 IRP Document
G. 2010 IMPA Annual Report