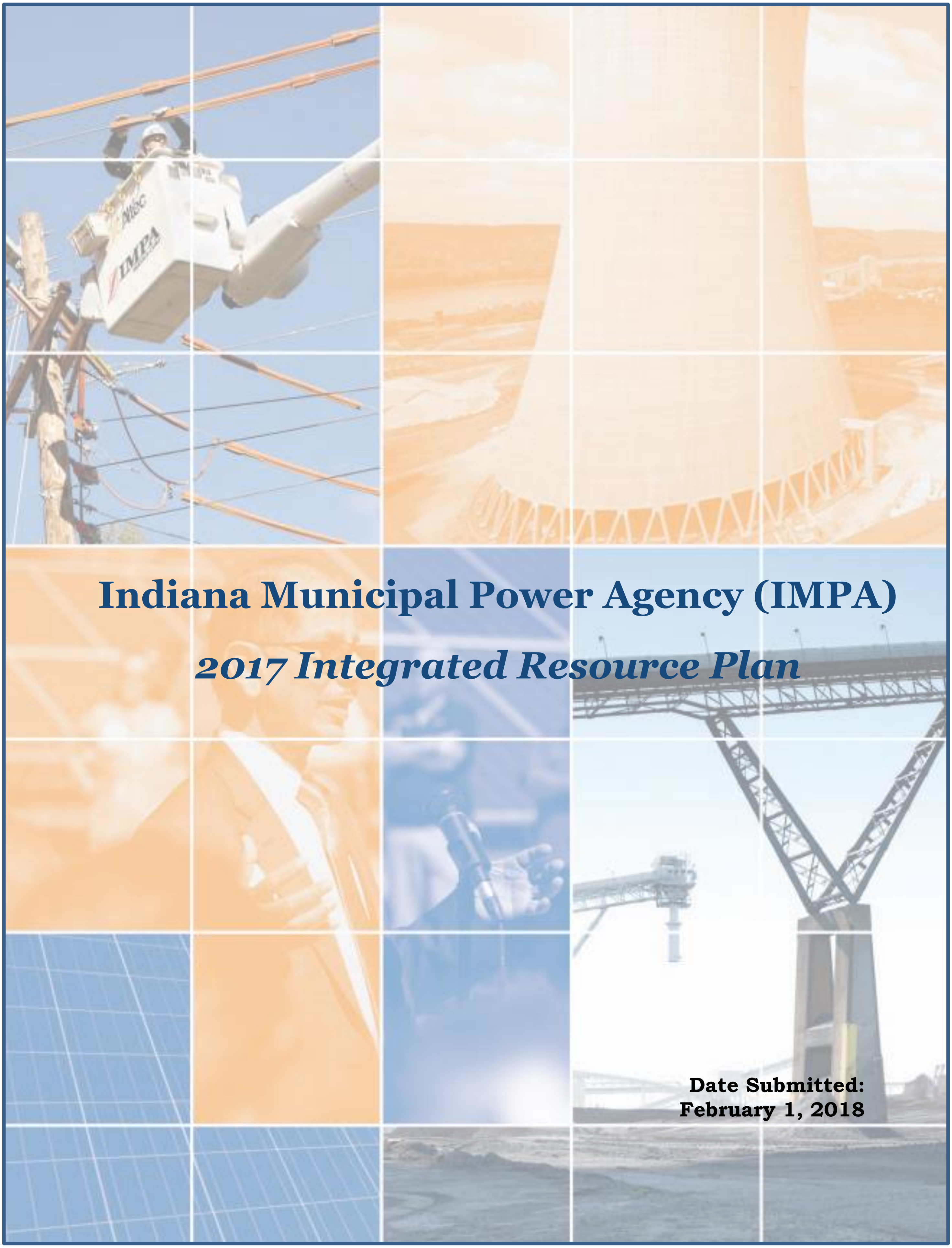

Indiana Municipal Power Agency (IMPA)

2017 Integrated Resource Plan

Date Submitted:
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11610 N. College Avenue | Carmel, IN 46032
317-573-9955

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AC	Alternating Current
AEP	American Electric Power
ASR	Average System Rates
C&I	Commercial and Industrial
CAAA	Clean Air Act Amendments
CAGR	Compound Annual Growth Rate
CC	Combined Cycle
CCR	Coal Combustion Residuals
CCS	Carbon Capture and Sequestration
CDD	Cooling Degree Days
CEP	Community Energy Program
CFL	Compact Fluorescent Light
CFR	Code of Federal Regulations
CHP	Combined Heat & Power
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CPNODES	Commercial Pricing Nodes
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
CT	Combustion Turbine
CWA	Clean Water Act
DEI	Duke Energy Indiana
DEOK	Duke Energy Ohio
DOE	U.S. Department of Energy
DSM	Demand-Side Management
EE	Energy Efficiency
EI	Energizing Indiana
EIA	Energy Information Administration
ELG	Effluent Limitations Guidelines
EPA	Environmental Protection Agency
FGD	Flue Gas Desulfurization
FERC	Federal Energy Regulatory Commission
FO	Forced Outage
FOM	Fixed Operation and Maintenance
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GHG	Greenhouse Gas
GW	Gigawatt
GWh	Gigawatt Hour
HAPS	Hazardous Air Pollutants
HDD	Heating Degree Days
HVAC	Heating, Ventilation, and Air Conditioning
HVDC	High Voltage Direct Current
I&M	Indiana-Michigan Power Company
IC	Internal Combustion
ICAP	Installed Capacity
IDEM	Indiana Department of Environmental Management
IGCC	Integrated Gasification Combined Cycle
IMEA	Illinois Municipal Electric Agency
IMPA	Indiana Municipal Power Agency
IPL	Indianapolis Power and Light
IRP	Integrated Resource Plan

ISO-NE	New England Independent System Operator
ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
JTS	Joint Transmission System
kW	Kilowatt
kWh	Kilowatt Hour
LFG	Landfill Gas
LG&E	Louisville Gas & Electric
LMP	Locational Marginal Price
LNG	Liquefied Natural Gas
LP	Linear Program
MATS	Mercury and Air Toxics
MIP	Mixed Integer Program
MISO	Midcontinent Independent System Operator
MMBtu	1 million British Thermal Units
MO	Maintenance Outage
MTEP	MISO Transmission Expansion Plan
MVP	Multi Value Project
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NIPSCO	Northern Indiana Public Service Company
NITS	Network Transmission Service
NOAA	National Oceanic and Atmospheric Association
NOx	Nitrogen Oxide
NPV	Net Present Value
NRC	U.S. Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
O&M	Operation and Maintenance
OECD	Organization for Economic Cooperative Development
OPEC	Organization of the Petroleum Exporting Countries
OTC	Over-The-Counter
OUCC	Indiana Office of Utility Consumer Counselor
PJM	Pennsylvania-New Jersey-Maryland
POTW	Publicly Owned Treatment Works
PPA	Purchase Power Agreement
PPM	Parts Per Million
PSEC	Prairie State Energy Campus
PSGC	Prairie State Generating Company
PTC	Production Tax Credit
PV	Photovoltaic
PVRR	Present Value of Revenue Requirements
RAM	Random Access Memory
RCRA	Resource Conservation and Recovery Act
RES	Renewable Energy Standard
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SCED	Security-Constrained Economic Dispatch
SCR	Selective Catalytic Reduction
SERC	SERC Reliability Corporation
SIGECO	Southern Indiana Gas and Electric Company
SIP	State Implementation Plan
SPP	Southwest Power Pool

SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
T&LF	Transmission and Local Facilities Agreement
TDU	Transmission Dependent Utility
TO	Transmission Owner
TW	Terawatt
TWh	Terawatt Hour
UCAP	Unforced Capacity
VOM	Variable Operation and Maintenance
WOTUS	Waters of the United States
WVPA	Wabash Valley Power Association
WWVS	Whitewater Valley Station

1 EXECUTIVE SUMMARY

The Indiana Municipal Power Agency (IMPA) is a wholesale electric utility serving the total electricity requirements of 61 communities under long-term power sales contracts. Each of IMPA's 61 members is a city or town with a municipally owned electric distribution utility. IMPA regularly reviews its projected loads and resources in order to ensure it is planning to meet its members' long-term load requirements in an economical, reliable and environmentally responsible manner. These planning activities are required under IMPA's risk management framework and are necessary to participate in the Regional Transmission Organization (RTO) markets. Pursuant to the requirements of 170 IAC 4-7, IMPA presents its 2017 Integrated Resource Plan (IRP). This report assesses IMPA's options to meet its members' capacity and energy requirements for wholesale service from 2018 through 2037.

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. IMPA's primary objective in developing its IRP is to minimize the price of electricity to its member utilities and their customers, while maintaining a reliable and environmentally responsible electricity supply. Additional objectives include minimizing risk through diversifying resources and fuel and maintaining flexibility to respond to changing economic and regulatory conditions.

In 2017, IMPA's coincident peak demand for its 61 communities was 1,128 MW, and the annual member energy requirements during 2017 were 6,098,477 MWh. IMPA projects that its peak and energy will grow at approximately 0.5% per year. These projections do not include the addition of any new members or customers beyond those currently under contract. Since the last IRP was filed, IMPA has added one new member, the Town of Troy, Indiana. Additionally, in August of 2017, the Village of Blanchester, Ohio, which had been an IMPA customer since 2007, became an IMPA member.

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

- Joint ownership interests in Gibson Station #5, Trimble County Station #1 & #2 and Prairie State Energy Campus #1 and #2;
- Operation and maintenance responsibility of Whitewater Valley Station #1 & #2;
- Five (5) dual fuel, natural gas or No.2 fuel oil, fired combustion turbines owned and operated by IMPA;
- Two (2) natural gas fired combustion turbines owned by IMPA and operated by Indianapolis Power and Light (IPL);
- Generating capacity owned by one (1) IMPA member;
- 17 Solar Parks located in member communities
- Long term power purchases from:
    - Indiana-Michigan Power Company (I&M)
    - Duke Energy Indiana (DEI)
    - Crystal Lake Wind, LLC (expires 12/31/2018)
- Short term contracts with market participants in MISO and/or PJM;
- The IMPA Energy Efficiency Program

IMPA's existing resources are diverse in terms of size, fuel type and source, geographic location and vintage. IMPA owns or controls generation in MISO and PJM as well as in the Louisville Gas & Electric/Kentucky Utilities (collectively LG&E) control area. In total, IMPA's generation and contractual resources reside in eight (8) different load zones in Indiana, Illinois, Iowa and Kentucky. This diversity reduces IMPA exposure to forced outages, locational marginal prices (LMPs), zonal capacity rates and regional fuel costs.

IMPA's energy efficiency program offers incentives in the form of rebates for residential and commercial and industrial (C&I) customers. Since 2012, IMPA's energy efficiency programs generated a cumulative savings of 115,864 MWh at the end of 2017 and a coincident peak reduction of 12.8 MW. In addition to its energy efficiency program, IMPA offers a demand response tariff, a net metering tariff, education and training. Furthermore, many IMPA members utilize various rate structures aimed at assisting customers in lowering or controlling their energy consumption or bills.

As discussed in the body of this report, IMPA has considered a variety of potential resources. These are discussed more fully in Section 6. IMPA's analysis has identified a plan that allows it to economically meet its members' future load growth while limiting future risks due to unforeseen legal or regulatory outcomes. The description of the modeling and planning process/selection is discussed in Sections 10 through 16.

1.1 ACTION PLAN

In the absence of the Clean Power Plan (CPP), IMPA's preferred resource expansion plan is shown below. The retirement of Whitewater Valley Station (WWVS) in 2025 is not imminent, but merely reflects the output of an optimization run under base conditions.

Table 1 2017 IRP Expansion Plan – Base Case Plan

Year	Capacity Losses MW Lost	Resource	Capacity Additions MW Added	Resource	Net MW
2018	(50)	PPA Expires	12 100	Solar Bilateral Capacity (18-20)	62
2019	(50)	Wind PPA Expires	12 50	Solar Wind PPA	12
2020			12	Solar	12
2021	(100) (100)	PPA Expires Bilateral Capacity Expires	12 200	Solar Bilateral Capacity (21-25)	12
2022			12	Solar	12
2023			12	Solar	12
2024			12	Solar	12
2025			12	Solar	12
2026	(90) (200)	WWVS Retires Bilateral Capacity Expires	12 200 50	Solar Advanced CC Wind PPA	(28)
2027			12	Solar	12
2028			12	Solar	12
2029					
2030					
2031					
2032					
2033					
2034	(190)	PPA Expires	260	Advanced CC	70
2035					
2036					
2037					
Total	(780)		992		212

While IMPA has a need for capacity and energy over the next 3 years (2018-2021); those needs will be fulfilled through market purchases as the positions are relatively small. IMPA's next resource decision comes in 2021 when a 100 MW purchase power agreement (PPA) expires. Current market capacity and energy prices are at historic lows. IMPA's Base Case plan calls for IMPA to cover these capacity shortfalls by engaging in bilateral capacity transactions and market energy hedges through approximately 2025. The Base Case plan also called on WWVS to be retired in 2026 when carbon emission legislation was assumed to begin. Since IMPA is long capacity in PJM, no additional capacity needs are required to make up for this retirement. Though WWVS is shown as being retired in this plan, no definitive retirement studies or decisions have been made.

IMPA's action plan is to delay, to the extent practical, its next major resource decision to allow time for more clarity on any carbon legislation that may arise. Given the extremely low prices of capacity and energy through 2027, purchasing now is a sound hedge against this uncertainty. As a carbon hedge, IMPA's strategic plan is to continue its Solar Park Program in which 10 to 12 MW of solar is added to IMPA's portfolio annually as well as replace the Crystal Lake wind farm PPA with one of similar size.

At this time, IMPA is not proposing the acquisition of any specific resource. IMPA will continue to evaluate resource options matching this plan and bring any firm proposals requiring Indiana Utility Regulatory Commission (IURC) approval before the IURC at the appropriate time.

Action Plan Items

1. Secure bilateral capacity in the five to seven year term
2. Secure market energy needs for same time frame
3. Continue monitoring the federal legislative process in order to gain more clarity on the future of CO_2 legislation
4. Continue IMPA Solar Park Program
5. Investigate replacement of 50 MW Crystal Lake wind contract
6. Continue the IMPA Energy Efficiency Program
7. Continue to develop IMPA's modeling capabilities in the areas of:
    - Zonal Optimization/Market Price Development
    - Portfolio Optimization
    - Stochastics and Risk Identification/Mitigation
    - Nodal Analysis

2 IMPA OVERVIEW

2.1 INTRODUCTION

Pursuant to the provisions of Indiana Code § 8-1-2.2-1 *et seq*., IMPA was created in 1980 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. Pursuant to the power sale contract with each of its members, IMPA is the full requirements power provider to its wholesale members. While IMPA's members serve a population of over 330,000 people, IMPA has no retail customers itself.

In addition to increasing its membership/customers from the initial 24 to 61 cities and towns, major milestones in IMPA's history include:

Table 2 Major IMPA Milestones

Date	Milestone
Fall 1982	Acquired an ownership share of Gibson Unit 5
Winter 1983	Began power supply operations to 24 members
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 2008	Signed Crystal Lake wind energy purchased power agreement
Winter 2011	Placed Trimble County Unit 2 into commercial operation
Summer 2012	Placed Prairie State Unit 1 into commercial operation
Fall 2012	Placed Prairie State Unit 2 into commercial operation
Summer 2014	Placed Frankton, Rensselaer and Richmond solar parks into commercial operation
Fall 2015	Placed Argos, Bainbridge, Crawfordsville, Peru, Pendleton and Tell City solar parks into commercial operation
Fall 2016	Placed Huntingburg, Washington and Waynetown solar parks into commercial operation.
Winter 2016/17	Anderson 1 solar park began commercial operation
Winter 2017/18	Anderson 2, Flora, Greenfield and Spiceland solar parks went into commercial operation.

2.2 RECENT ACTIVITIES – KEY EVENTS SINCE LAST IRP

Since IMPA submitted its last IRP to the IURC on November 2, 2015, the following events have taken place:

- On January 13, 2016 IMPA closed on the sale of its Power Supply System Refunding Revenue Bonds, 2016 Series A&B. The purpose of these bonds was to advance refund outstanding bonds at lower interest rates.
- On March 9, 2016 IMPA closed on the sale of its Power Supply System Refunding Revenue Bonds, 2016 Series C. The purpose of these bonds was to advance refund outstanding bonds at lower interest rates.
- In the fall of 2016, the Huntingburg. Washington and Waynetown solar parks began commercial operations.
- In the winter of 2017, the Anderson 1 solar park began commercial operations.
- On December 1, 2016, the City of Troy, Indiana became the 60th member of IMPA.
- On August 22, 2017 the Village of Blanchester, Ohio became the 61st member of IMPA.
- On December 7, 2017 IMPA closed on the sale of its Power Supply Revenue Bonds, 2017 Series A. The purpose of these bonds was to fund capital improvements on existing Agency assets and advance refund existing bonds.
- In December 2017, the Anderson 2, Flora, Greenfield and Spiceland solar parks began commercial operations.

3 IRP OBJECTIVES AND PROCESS

3.1 IRP Rules (170 IAC 4-7)

The IURC developed guidelines in 170 IAC 4-7-1 *et seq*. for electric utility IRPs in order to assist the IURC in its administration of the Utility Powerplant Construction Law, IC 8-1-8.5. IMPA and seven other utilities across the state of Indiana are subject to the IRP rules. Section 18 of this IRP summarizes the rules, along with an index of IMPA's responses to those rules. (Note: The last four IMPA IRPs have been filed following proposed rules that the state has never promulgated)

3.2 IMPA IRP Objectives

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. IMPA's primary objective in developing its IRP is to minimize the price 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.

3.3 IMPA Planning Criteria

IMPA serves wholesale load in both MISO and PJM and must comply with the resource adequacy requirements of each RTO for its load in that RTO. For long-term planning and this IRP, IMPA utilizes a 15% reserve margin for its MISO and PJM loads. In addition, loads are adjusted for area specific transmission loss factors, consistent with MISO and PJM capacity construct methodologies. From a resource planning standpoint, resource capacity was determined to be summer ratings for thermal resources, while wind resources were reduced by 85% of nameplate capacity and solar resources were reduced by 50% of nameplate capacity. These values are consistent with MISO and PJM intermittent capacity crediting methodologies.

IMPA plans its resources to meet its projected load and does not allow the expansion models to add resources for speculative sales. IMPA does allow the model to purchase market capacity in the future, but these are limited to small quantities and meant to simulate the normal final balancing that takes place in today's RTO capacity markets. This buffer also allows flexibility in the future regarding load uncertainty, energy efficiency, demand response and renewables development.

3.4 IMPA Planning Process

Formulating an IRP is a multistep project that utilizes many disciplines including engineering, environmental science, statistics and finance. The basic steps of the IRP process are summarized below, with references to where further information can be found in this document.

1. Evaluation of Existing System – 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. (Section 4)

2. Long Range Forecast Development – Annually, IMPA develops a 20-year projection of peak demands and annual energy requirements. The load forecast is developed using a time-series, linear regression equation for each load zone. (Section 5)

3. Resource Options and Environmental Compliance – This step involves the description and screening of various resource alternatives. Additionally, transmission service and compliance with future environmental issues are discussed. (Sections 6-8)

4. Software Overview / Data Sources – This section describes the software and data sources used to perform the analysis. (Section 9)

5. Scenario Development – IMPA creates scenarios as a structured way to think about the future as scenario planning is a proven tool to better anticipate and respond to future risks and opportunities. (Section 10)

6. Evaluation of Resource Alternatives and Resource Optimization – After scenarios have been established, IMPA modeling efforts center around building the most efficient zonal system of resources for a given scenario. From that most efficient system, IMPA can then select assets from that system to create the optimal IMPA portfolio for that scenario. (Sections 11-13)

7. Plan Evaluation – A crucial part of the IRP process is evaluating how a portfolio performs under various stochastic drivers and its sensitivity to movements of certain variables. (Section 14-15)

8. Plan Selection – Description of preferred plan and basis for selection. (Section 16)

9. Short Term Action Plan – Description of steps necessary to implement the preferred plan. (Section 17)

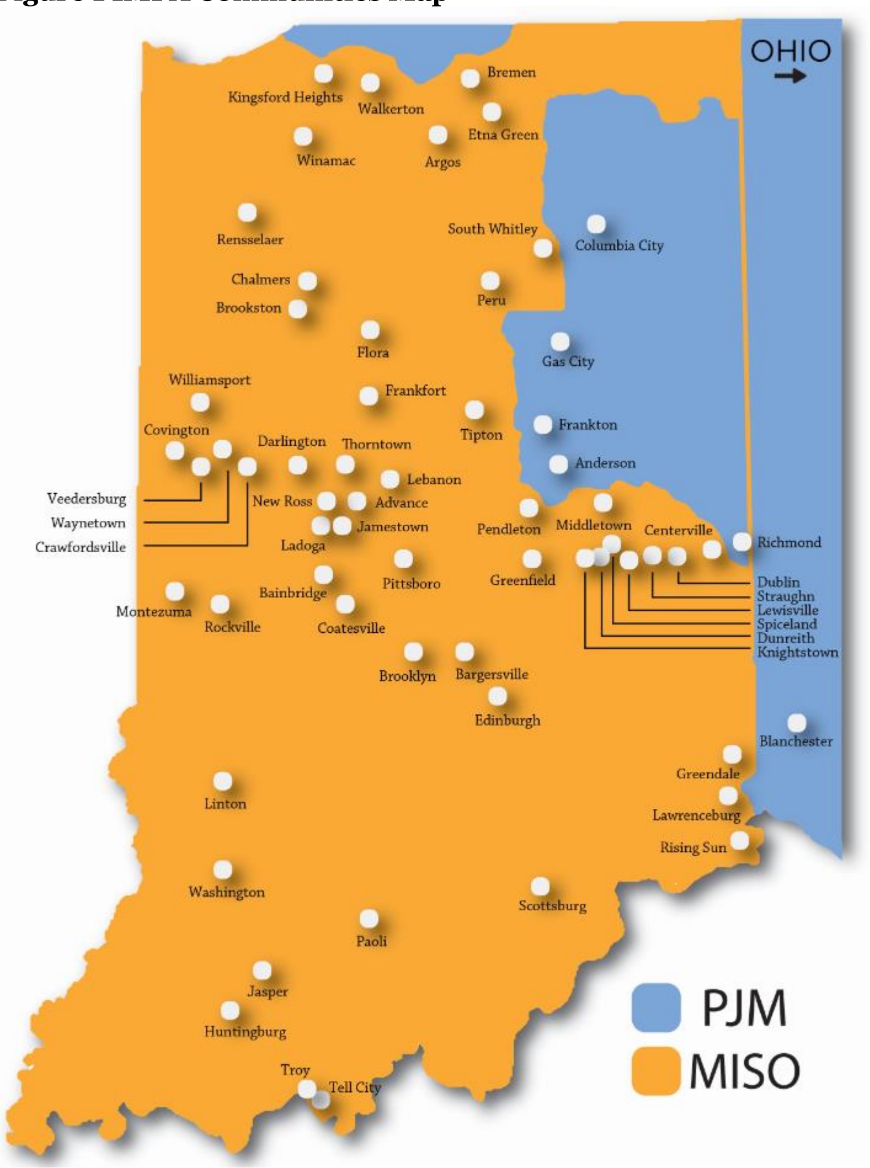
4 EXISTING SYSTEM

4.1 IMPA SYSTEM DESCRIPTION

IMPA is a wholesale electric utility serving the total electricity requirements of 61 communities. Each of IMPA's 61 members is a city or town with a municipally owned electric distribution utility. IMPA has no retail customers and no direct communication or other interaction with the member's retail customers, except as specifically requested by the member.

IMPA operates in both the MISO and PJM RTOs. IMPA has load in five load zones and generation resources connected to seven zones within the RTO footprints, plus two resources outside of the RTOs. IMPA's load is divided approximately two-thirds within the MISO footprint and one-third in PJM.

Figure 1 IMPA Communities Map



4.2 Loads and Load Growth

IMPA's member communities are located in five different load zones in MISO and PJM. When IMPA began operations in 1983, it served 24 communities. IMPA now serves 61 communities. The following table lists the 61 communities that IMPA serves along with the load zone, RTO in which they are located and the approximate percentage of IMPA's total load.

Table 3 IMPA Communities

RTO	Load Zone	% of Load	Community
MISO	Duke-IN	50%	Advance, Bainbridge, Bargersville, Brooklyn, Centerville, Coatesville, Covington, Crawfordsville, Darlington, Dublin, Dunreith, Edinburgh, Flora, Frankfort, Greendale, Greenfield, Jamestown, Knightstown, Ladoga, Lawrenceburg, Lebanon, Lewisville, Linton, Middletown, Montezuma, New Ross, Paoli, Pendleton, Peru, Pittsboro, Rising Sun, Rockville, Scottsburg, South Whitley, Spiceland, Straughn, Thorntown, Tipton, Veedersburg, Washington, Waynetown, Williamsport
	NIPSCO	7%	Argos, Bremen, Brookston, Chalmers, Etna Green, Kingsford Heights, Rensselaer, Walkerton, Winamac
	VECTREN	10%	Huntingburg, Jasper, Tell City, Troy
PJM	AEP-I&M	32%	Anderson, Columbia City, Frankton, Gas City, Richmond
	Duke-OH	1%	Blanchester, Ohio

In 2017, IMPA's peak demand for its 61 communities was 1,128 MW, and the annual member energy requirements during 2017 were 6,098,477 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.

4.3 EXISTING SUPPLY-SIDE RESOURCES

IMPA currently has a variety of supply-side resources, including:

- Joint ownership interests in Gibson Unit 5, Trimble County Units 1 and 2, Prairie State Units 1 and 2;
- Operation and maintenance responsibilities for Whitewater Valley Units 1 and 2;
- Seven combustion turbines wholly owned by IMPA;
- 17 solar parks located in IMPA member communities;
- Generating capacity owned and operated by one of IMPA's members;
- Long-term 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.
- Crystal Lake Wind Energy Center in Hancock County, Iowa.

Some of these resources have contractual limitations that restrict their use to a particular local balancing area or delivery point. Tables summarizing the key characteristics of IMPA's generating units and long term purchased power agreements are shown in Appendices D1 and D2. The resources and contracts are described in more detail on the following pages.

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 MW coal-fired generating facility located in southwestern Indiana. It is equipped with particulate, SO_2 and NO_x removal facilities (selective catalytic reduction (SCR) system) and an SO_3 mitigation process. The boiler has also been retrofitted with low NO_x burners. The 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. DEI has multiple coal contracts of varying lengths to supply the five units at Gibson Station. 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 45-50 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.

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 490 MW coal-fired unit located in Kentucky on the Ohio River approximately 15 miles from Madison, Indiana. The unit is equipped with low NO_x burners, an SCR system, a pulse jet fabric filter, a dry electrostatic precipitator, an SO_3 mitigation process, and wet flue gas desulfurization. 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 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 28-49 day level.

LG&E operates Trimble County 1 under the "Participation Agreement By and 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. Transmission service is provided from the plant to the LGEE-MISO interface.

Trimble County 2

IMPA constructed Trimble County 2 jointly with LG&E and IMEA. Commercial operation commenced in January 2011. Trimble County 2 is a 731 MW (net) unit with a supercritical, pulverized coal boiler and a steam-electric turbine generator. Unit 2 is equipped with low-NO_x burners, an SCR system, a dry electrostatic precipitator, pulse jet fabric filter, wet flue gas desulfurization, and a wet electrostatic precipitator. The coal is eastern bituminous coal (including, potentially, Indiana coal) blended with western sub-bituminous coal. All coal arrives at the site via barge on the Ohio River. LG&E uses the same procedures for selection and delivery of coal to Trimble County 2 as it uses for Trimble County 1. Trimble County 2 flue gas exhausts through two flues in the existing site chimney.

The ownership arrangement for Trimble County 2 has the same undivided ownership 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 under a participation agreement similar to that used to operate Trimble County 1. Transmission service is provided from the plant to the LGEE-MISO interface.

Prairie State Project

The Prairie State Energy Campus (PSEC) consists of the Prairie State Units 1 & 2, related electric interconnection facilities, the Lively Grove mine, the near-field coal combustion residuals (CCR) disposal facility, and the Jordan Grove CCR disposal facility. IMPA is one of nine public power entities that collectively direct the Prairie State Generating Company (PSGC) in operating the PSEC. IMPA has a 12.64% interest in the PSEC. Both units began commercial operation in 2012.

The PSEC is in the southwest part of Washington County, Illinois, approximately 40 miles southeast of St. Louis, Missouri. The plant includes two steam-electric turbine generators totaling approximately 1,600 MW. The plant's two boilers are supercritical, pulverized coal steam generators with low-NO_x burners, SCR systems, dry electrostatic precipitators, wet flue gas desulfurization and wet electrostatic precipitators.

The project also includes contiguous coal reserves owned by the project participants 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. PSGC owns or controls 100% of the surface property around the mine portal.

IMPA Combustion Turbines

IMPA has seven wholly-owned combustion turbines. 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 IMPA 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. IPL operates these two units on behalf of IMPA. The units are both GE-7EA machines and are natural gas fired. Citizens Energy Group delivers the natural gas to the Georgetown Station from the Panhandle Eastern Pipeline system. IPL has the responsibility to ensure IMPA's units comply with applicable environmental requirements.

IMPA Solar Parks

In 2013, IMPA began a program to construct photovoltaic solar parks in member communities. By the end of 2017, 17 facilities totaling 36.7 MW had been placed in service. These solar parks range in size from .3 to 8.1 MW. Continued development of solar parks is planned through the first half of the IRP planning period.

Member-Owned Capacity

IMPA members Rensselaer and Richmond own generating facilities. The following paragraphs briefly describe those member facilities.

Rensselaer

Rensselaer's generating plant consists of six internal combustion engines with a total tested capability of approximately 18 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 available as a backup.

The Rensselaer generating plant is exempt from the Title IV Acid Rain provisions of the Clean Air Act Amendments (CAAA), and Cross-State Air Pollution Rule (CSAPR) requirements since all the units are under 25 MW. Unit 5 has been reclassified as an "emergency unit" for compliance with the Reciprocating Internal Combustion Engines Rule. This means Unit 5 can be operated for emergency use only and is not considered a capacity resource.

Richmond

On June 1, 2014 IMPA entered into an amended and restated capacity purchase agreement with Richmond Power & Light, obtaining the rights to operate and maintain WWVS. WWVS consists of two coal-fired generating units with a current maximum tested capability of approximately 30 MW and 60 MW, respectively. IMPA purchases coal on a short-term, spot market basis to support operation of the plant which is generally used to fulfill peaking needs.

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". I&M is responsible for providing the capacity losses and reserves under this contract. The contract was extended in 2010 and now has an expiration date of May 31, 2034.

On June 1, 2017, a new 100 MW contract with DEI began. The new contract provides dispatchable energy with minimum annual load factor requirements. The demand charge is a negotiated fixed rate while the fuel charge derived from a cost based formula. This contract also covers capacity losses and reserves as well as LMP losses and congestion. The contract expires on May 31, 2021.

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 (subsequently renegotiated to 48 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 is currently researching potential replacement wind energy contracts to begin when this contract expires.

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. IMPA currently has market capacity and/or energy purchases extending out as far as 2025.

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 charge over its base rate. As discussed above, IMPA currently has access to over 36 MW of solar facilities and has a contract for the purchase of 48 MW of wind energy.

IMPA members implement the Green Power rate if they desire. Currently, IMPA members have 84 retail customers on the Green Power rate and sell over 1,200 MWh per year under the program.

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. As with the Green Power rate, the net metering tariff is implemented at the member's discretion. At this time, IMPA knows of 20 net metering installations in its members' service territories.

IMPA has been approached by retail customers of members wishing to install renewable systems that exceed the maximum size allowed under the IMPA net metering tariff. IMPA's preferred method of handling these large systems is to sign a contract to purchase the excess power at an avoided cost type rate. At this time, IMPA purchases excess power from three customer-owned solar projects.

Retail Customer-Owned Generation (Non-Renewable)

IMPA has a contract with one commercial/industrial customer of an IMPA member to purchase excess generation from its onsite generation facilities. Under the current contract, the customer has been selling small amounts of energy to IMPA under a negotiated rate.

IMPA does not currently have any customers on the system that operate a combined heat and power (CHP) system. While under the right circumstances CHP systems could be beneficial to both the customer and IMPA, the right mix of site specific operating conditions and economics must be in place for both parties in order for a CHP project to go forward.

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.

4.4 EXISTING DEMAND-SIDE RESOURCES

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

Historic Programs:

IMPA CFL Rebate Program (2008-2010)

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 energy efficiency program implementation date of January 1, 2011, this program ended in 2010 with the last distribution of coupons occurring in the summer of 2010.

IMPA Streetlight Upgrades Program (2010-2012)

IMPA, on behalf of its participating communities, was one of 20 grant applicants selected from around the country in June 2010 to receive a Department of Energy (DOE) Energy Efficiency and Conservation Block Grant through the American Recovery and Reinvestment Act. IMPA was awarded $5 million on behalf of its members to implement local streetlight retrofitting programs in the Agency's member communities.

The street light selection process was so successful that IMPA was able to extend the original plan from approximately 19 communities, 6,800 lights and 3.4 million kilowatt-hours of savings to 32 communities, approximately 11,000 lights and 6.1 million kilowatt-hours of savings. Over the course of 2011, the participating communities replaced and retrofitted their existing streetlights with the new energy efficient lights. IMPA, with its team of participating communities, was the first grant recipient to complete its project under this DOE grant program. In 2012, the program was extended to several more communities resulting in an additional 5.5 million kilowatt-hours of savings.

Community Energy Program (CEP)

During 2011, IMPA assisted member communities in applying for the opportunity to participate in a Community Energy Program (CEP) offered through the Indiana Office of Energy Development. Eight members were awarded with CEP-provided energy audits of the public facilities in their communities and personalized strategic energy plans with both short and long-term energy efficiency goals.

The program included an inventory of all energy usage at public facilities in the community, a full energy audit to identify potential energy saving measures, an established baseline for utility bills, a list of short and long-term energy goals for the community, suggestions to streamline energy decision-making and purchasing processes, ideas for funding energy efficiency projects, as well as a public meeting to inform the entire community about the new, comprehensive energy plan. The CEP was funded through the Energy Efficiency and Conservation Block Grant Program, the same program that provided funds for the street lighting effort.

Energizing Indiana (2012-2013)

IMPA voluntarily participated in the statewide energy efficiency program known as Energizing Indiana in 2012 and 2013. Energizing Indiana ended for all Indiana utilities in 2014.

Current Programs:

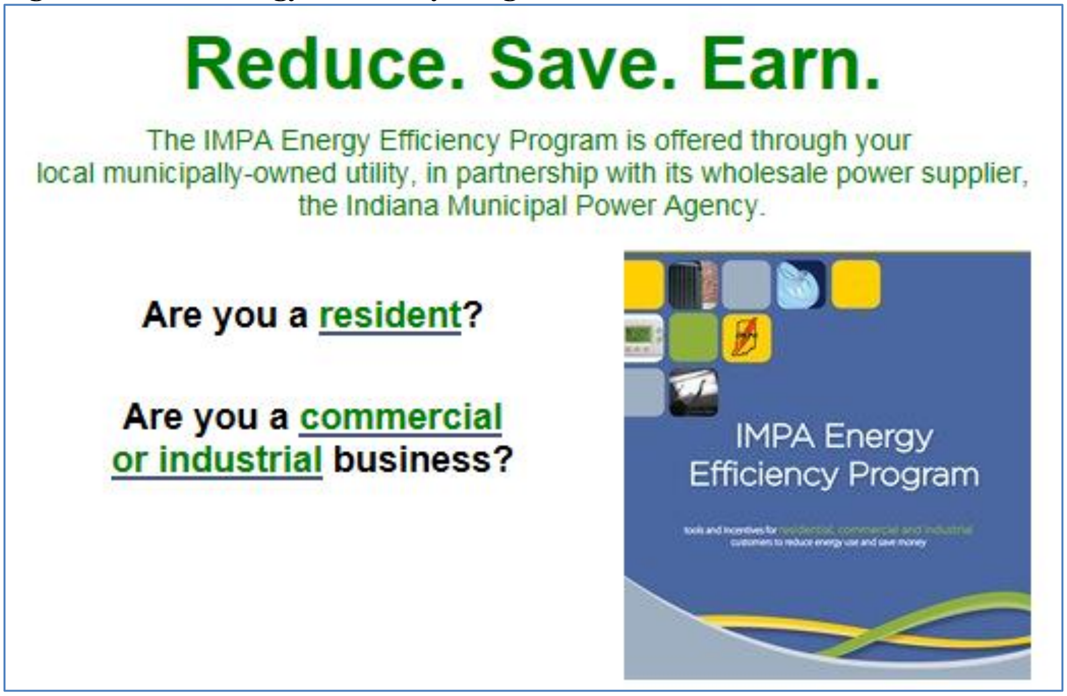
IMPA Energy Efficiency Program

In early 2011, IMPA launched the IMPA Energy Efficiency Program, designed to help retail customers in the Agency's member communities save money through incentives for implementing energy-saving measures in four different categories: energy efficient lighting; heating, ventilation and air conditioning (HVAC); motors, fans & drives; and refrigeration, food service and controls. IMPA worked with member utilities to market the program, educate customers and build relationships with local vendors to implement the energy saving measures. During 2011, the Agency as a whole saw approximately 90 companies participate in the program, representing 25 member communities throughout the state of Indiana.

In 2012 and 2013, IMPA voluntarily participated in Energizing Indiana, a state-wide energy efficiency program in order to gain experience and evaluate the cost-effectiveness of a variety of residential, commercial, and industrial programs. The savings from these efficiency efforts was 32 million kWh (2012) and 52.7 million kWh (2013), annually.

In 2014, IMPA returned to the more cost-effective, self-managed energy efficiency program, which it first launched in 2011. IMPA added residential rebates for HVAC systems in addition to its menu of C&I rebates. The link to the IMPA Energy Efficiency website is shown below.

Figure 2 IMPA Energy Efficiency Program



Source: www.impa.com/energyefficiency

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 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.

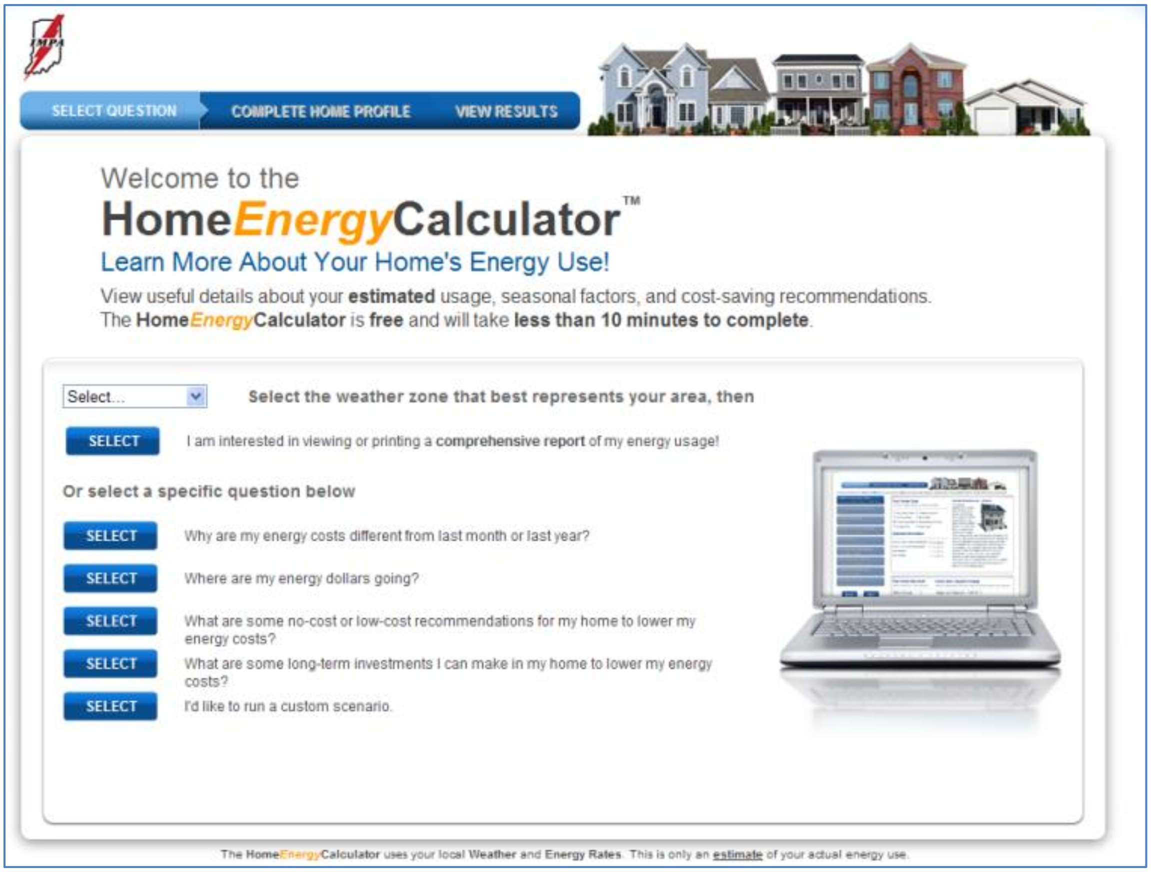
Each issue of Municipal Power News includes a quiz. Customers may enter their answers in a drawing at IMPA. Correct responders are mailed a small energy efficiency kit consisting of efficient light bulbs, weather stripping, outlet insulators and an LED nightlight. IMPA has distributed approximately 800 of these kits through this and other delivery mechanisms.

IMPA's website at www.impa.com/energyefficiency includes energy efficiency, conservation and safety information for consumers as well as providing 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.

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 and potential savings from higher efficiency appliances. 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). The site is also advertised in IMPA's newsletters.

Figure 3 IMPA Home Energy Calculator



Source: www.impa.com/energycalculators

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 are participating in 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, advanced meter infrastructure/automatic meter reading and streetlight replacement with more efficient lamps.

Summary

Through the end of 2017, IMPA's energy efficiency programs have generated a cumulative savings of 116,000 MWh and a coincident peak reduction of approximately 12.9 MW.

Table 4 Energy Efficiency Results (2009-2017)

MWh	<2012	2012	2013	2014	2015	2016	2017
Residential	214	9,459	15,522	16	22	27	19
Commercial and Industrial	16,292	22,521	37,155	2,186	2,126	7,492	2,956
Annual Total (MWh)	16,506	31,980	52,677	2,202	2,148	7,519	2,975
Cumulative Total (MWh)	16,506	48,486	101,163	103,365	105,513	113,032	116,007

MW (Non-Coincident)	<2012	2012	2013	2014	2015	2016	2017
Annual Total (MW)	3.414	7.194	11.468	0.633	0.422	1.531	0.647
Cumulative Total (MW)	3.414	10.608	22.076	22.709	23.131	24.662	25.309

MW (Coincident)	<2012	2012	2013	2014	2015	2016	2017
Annual Total (MW)	0.693	3.907	6.279	0.360	0.188	0.950	0.472
Cumulative Total (MW)	0.693	4.600	10.879	11.239	11.427	12.377	12.849

4.5 IMPA Transmission

A large portion of IMPA's load is connected to the Joint Transmission System (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.

IMPA owns, but does not operate transmission facilities. 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 on behalf of the entire JTS. (See Appendix G for a statement on Form 715.)

IMPA is a member of MISO as a Transmission Owner (TO). DEI and WVPA are also TO 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 the TOs 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.

Approximately two thirds of IMPA's load is connected to delivery points on MISO-controlled transmission lines of the JTS, Northern Indiana Public Service Company (NIPSCO) and Vectren. The remaining portion of the members' load is connected to delivery points on the AEP and Duke-OH transmission systems, located in the PJM footprint. IMPA is a transmission dependent utility (TDU) for all load not connected to the JTS system, approximately 50%. For these loads, IMPA purchases Network Integration Transmission Service (NITS) under the appropriate zonal tariff.

5 LOAD FORECAST

As a basis for this IRP, IMPA developed a 20 year projection of peak demands and annual energy requirements by month. This section describes the methods employed, their results, historical performance, and alternative methods of forecasting.

5.1 LOAD FORECAST METHODOLOGY

Traditional linear regression was utilized for forecasting both energy and expected peak demand across IMPA's five load zones. As with most exercises with linear regression, the first task was to determine cause and effect relationships between IMPA's energy demand and possible drivers of that demand. The National Renewable Energy Laboratory (NREL) notes that historical demand drivers are population and economic growth, along with "other emerging trends…"[1] IMPA's experience is in agreement with NREL, that macroeconomic variables are historically significant drivers of energy demand. In addition, weather and calendar related variables (i.e., peak days in month) have historically proven to be significant predictors of demand and were included for consideration. Factors that also are expected to have impacts in the future are policy changes, penetration of new or emerging technologies (e.g., electric vehicles), and end user investment in efficiency products such as energy efficient appliances or smart thermostats. Table 5 illustrates variables that were tested for statistical significance and fit for each of the load zones modeled.

Table 5 Energy Forecast Variables

Variable Type	Variable
Calendar Impact	Peak/Off Peak Days
Weather Impact	Heating and Cooling Degree Days
Energy Efficiency	Energy Intensity (Btu/$ of real GDP)
Economic	Household Debt
Economic	Real GDP
Population	Total Households
Economic	Indiana Non-Farm Payrolls

In addition to these fundamental variables, a dummy variable for peak season (e.g., June-August) was contemplated for the energy forecast. Similar regression methods were used to arrive at IMPA's peak demand forecasts for each of the five load zones. IMPA sees the key determinants of peak demand as being driven by expected daily energy use and meteorological factors such as temperature, wind speeds, and barometric pressure. Table 6 illustrates the variables considered in the peak demand modeling process.

Table 6 Peak Demand Forecast Variables

Peak Demand Variables
Expected Daily Load (MWh)
Temperature
Wind Speed
Barometric Pressure
Intraday Temperature Deviations

In addition dummy variables were considered to isolate peak day conditions intra month.

[1] http://www.nrel.gov/docs/fy12osti/52409-3.pdf

The primary goal for both the energy and demand forecast was to select variables with transparent, accurate and unbiased datasets and to keep models across load zones as consistent as statistically possible.

5.2 Load Data Sources

Meter level load data was drawn from IMPA billing databases and aggregated into the 5 load zones: Duke-Indiana, Vectren, NIPSCO, AEP, and Duke-Ohio. Data was pulled from 2004 through 2016 for all load zones except Duke-Ohio. Duke-Ohio data was only available from the start of 2007. For the monthly load forecast, this resulted in 156 observations for four of the five load zones and 120 observations for Duke-Ohio. Monthly heating and cooling degree days (HDD and CDD) were obtained from historical daily data from Wunderground[2] that use a base temperature of 65 degrees Fahrenheit. Weather data was selected from relevant weather stations for the relevant load zone. Table 7 illustrates the weather stations used for each load zone.

Table 7 Reference Weather Stations

Load Zone	Weather Station
DUK-IN	Indianapolis
Vectren	Evansville
NIPSCO	Valparaiso
AEP	Muncie/Anderson
DUK-OH	Cincinnati

Other meteorological data points were also obtained from Wundground for the relevant load zones. All economic variables, save Energy Intensity, were obtained from the St. Louis Federal Reserve FRED database.[3] Energy Intensity, as set forth by the Energy Information Administration (EIA), is defined as "energy consumption per unit of gross domestic product."[4] In IMPAs view, this variable is useful for capturing the impacts of energy efficiency on demand for electricity over time. For the purposes of modeling, IMPA calculated this variable by using the EIA's reported Energy Consumed by Residential Sector data and Real GDP figures from the St. Louis Federal Reserve FRED database. This data was converted into a Btu/$ of real GDP figure and regressed against historical loads, along with the variables listed in Tables 1 and 2 and weather data from Table 3.

5.3 Load Forecast Model Development

IMPA has prepared an energy and demand forecast for each of its five principal load zones. Variables listed in Tables 5 and 6 were used as independent variables against the dependent variables of the respective load zone energy or peak demand.

<u>Energy Forecast Development</u>

The initial focus was establishing a model for the Duke Indiana load zone as this represents approximately half of IMPA's total obligations. Once that model was established, those variables were then selected as a starting point to regress against the remaining load zones. For the Duke Indiana load forecast, the statistically significant variables were: Peak Days, Off-Peak days,

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[2] https://www.wunderground.com/history/
[3] https://fred.stlouisfed.org/
[4] https://www.eia.gov/todayinenergy/detail.php?id=27032

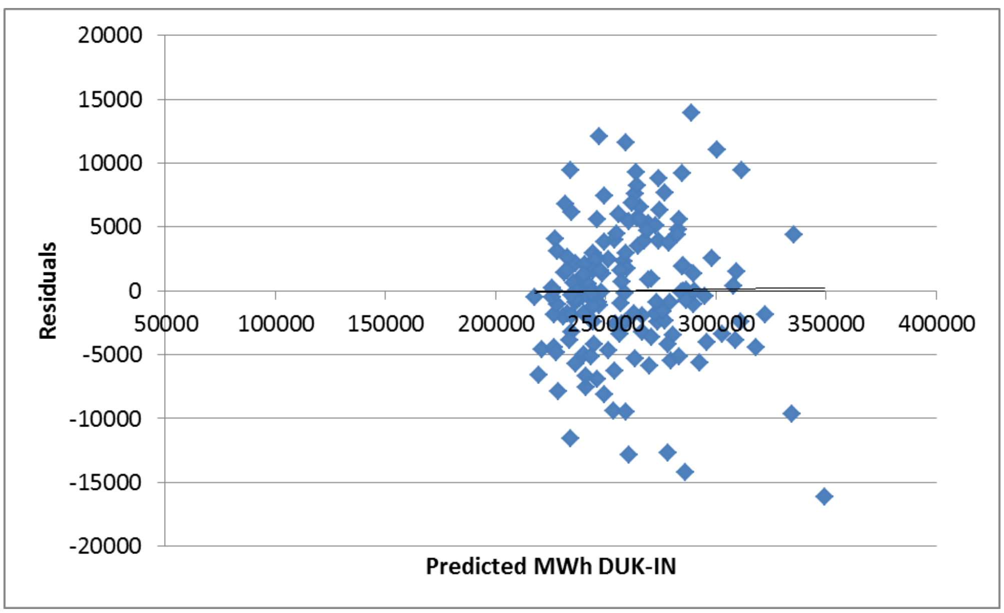
Indianapolis HDD and CDD, a peak season dummy variable, Energy Intensity (Btu/$ of real GDP), Household Debt As a % of Disposable Income, and Total Indiana Non-Farm Payrolls.

Table 8 Energy Forecast Variables

Load Zone	Variables of Significance
DUK-IN	On/Off Peak Days, HDD/CDD, Peak Season Dummy, Energy Intensity, Household Debt as % of Disposable Income, Indiana Non-Farm Payrolls
Vectren	On/Off Peak Days, HDD/CDD, Peak Season Dummy, Energy Intensity, Household Debt as % of Disposable Income, Indiana Non-Farm Payrolls
NIPSCO	On/Off Peak Days, HDD/CDD, Energy Intensity, Real GDP
AEP	On/Off Peak Days, HDD/CDD, Peak Season Dummy, Energy Intensity, Real GDP
DUK-OH	On/Off Peak Days, HDD/CDD, Energy Intensity, Household Debt as % of Disposable Income

All independent variables were statistically significant with T statistics greater than 2 and P values below .05. The figure below illustrates residuals (MWh) of the model plotted against predicted energy (MWh), showing no patterns of heteroscedasticity or nonlinear behavior.

Figure 4 Forecast Residuals DUK-IN Energy Model



With a core model selected for the single largest load zone, the same variables were used as independent variables against the Vectren, NIPSCO, AEP, and Duke Ohio load zones. In certain cases the variables that were significant predictors of load for Duke Indiana proved to be statistically significant for other load zones (e.g., Vectren) while other load zones required the substitution of some variables due to statistical insignificance or poor model fit.

Ultimately, the energy models were refined by incrementally adding independent variables to linear regression models and adding relevant variables until model fit improved and standard error deteriorated. Ultimate model selection was determined by statistical significance of the variables, explanatory power of the model, and the standard error of the model. All else being equal, models with lower overall standard error were selected. Table 9 below illustrates the variables selected for each load zone.

Peak Demand Forecast Development

The key driver of each load zone demand forecast was daily energy use during the day the peak demand was set. As such, a principal driver of the demand forecast was the monthly average energy forecast. For the initial year of the demand forecast (2017), the monthly load forecast was scaled to a daily energy use number based on historical figures. For subsequent years, this initial energy forecast was grown at a year over year growth rate that was consistent with the load forecast. The remaining variables for the peak demand forecast were based on historical averages observed during periods of peak demand. Note that for the demand forecasts, four separate, seasonal forecasts were developed for each of the 4 main load zones, leading to 16 distinct forecasts (plus one year round forecast for the DUK-OH load zone). Table 8 summarizes the variables used.

Table 9 Demand Forecast Variables

Season/Area	DUK-IN	Vectren	NIPSCO	AEP	DUK-OH
Spring	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	Daily Peak MWh, High Temp	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	DUK-OH Load, HDD/CDD for Cincinnati
Summer	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	Daily Peak MWh, Difference between High and Low Temp, Average Wind Speed	Peak Dummy, Daily Peak MWh, High Temp	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	DUK-OH Load, HDD/CDD for Cincinnati
Fall	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	Daily Peak MWh, High Temp	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	Peak Dummy, Daily Peak MWh, High Temp, Average Wind Speed	DUK-OH Load, HDD/CDD for Cincinnati
Winter	Peak Dummy, Daily Peak MWh, Low Temp, Maximum Wind Speed	Daily Peak MWh, Average Barometric Pressure	Peak Dummy, Daily Peak MWh, Low Temp, Maximum Wind Speed	Peak Dummy, Daily Peak MWh, Low Temp, Maximum Wind Speed	DUK-OH Load, HDD/CDD for Cincinnati

Demand models were refined in a similar manner as the energy forecasts. Feeding the demand forecast, however, was the monthly energy forecast shaped to a daily energy expectation in MWh, in addition to a subset of the variables contemplated in Table 6. As was the case with the energy forecasts, models were selected ultimately on the basis of statistical significance of the independent variables, the explanatory power of the model, and standard error of the model.

One key difference in developing the peak demand forecast was the use of seasonal models. Historical load data was first sorted, along with the selected independent variables in descending order ranked by peak MW. Regressions were then run on only the top 10% of observations. Ultimately this proved to improve fit and isolate variables that impacted peak loads more accurately.

5.4 INDEPENDENT VARIABLE FORECASTS

One challenge in selecting independent variables is that while some variables may prove to be statistically significant, finding independent and potentially unbiased forecasts to inform the forecast model can be problematic. While weather and calendar impacts are easily handled, independent/unbiased forecasts for variables such as payrolls and even state specific economic growth are at best, stale and at worst difficult to find. As a result, IMPA has relied on macroeconomic variables that have a more national scope or can otherwise be modeled using variables with widely available forecasts.

Each load zone, where statistically practical, used similar independent variables. Calendar impacts (e.g., peak days in the month), were determined by the use of a calendar and adjusted for holidays. Heating and Cooling Degree Days were established using 20 year historical averages for the pertinent weather stations. For those forecasts that used energy intensity as a measure of total Btu/$of real GDP, energy intensity was estimated to decline at a roughly 2% year over year rate as set for by the International Energy Agency's 2016 "Energy Efficiency Market Report: 2016" for countries in the Organization for Economic Cooperative Development (OECD).[5] Household debt as a percentage of disposable income was simply regressed against real GDP as the independent variable and indicated that economic expansion was a reasonable predictor of increasing household leverage. Real GDP was also used as an independent variable for predicting future trends in Indiana Non-Farm Payrolls. With Real GDP playing a key role in informing the future trends of other independent variables in the IMPA load forecast, IMPA canvassed websites of various governmental agencies and global organizations that supply growth forecasts and applied a simple average of the survey estimates as the projected Real GDP growth rate. Table 10 illustrates this survey data and the growth rate assumption applied.

[5] https://www.iea.org/eemr16/files/medium-term-energy-efficiency-2016_WEB.PDF

Table 10 Real GDP Growth Forecasts

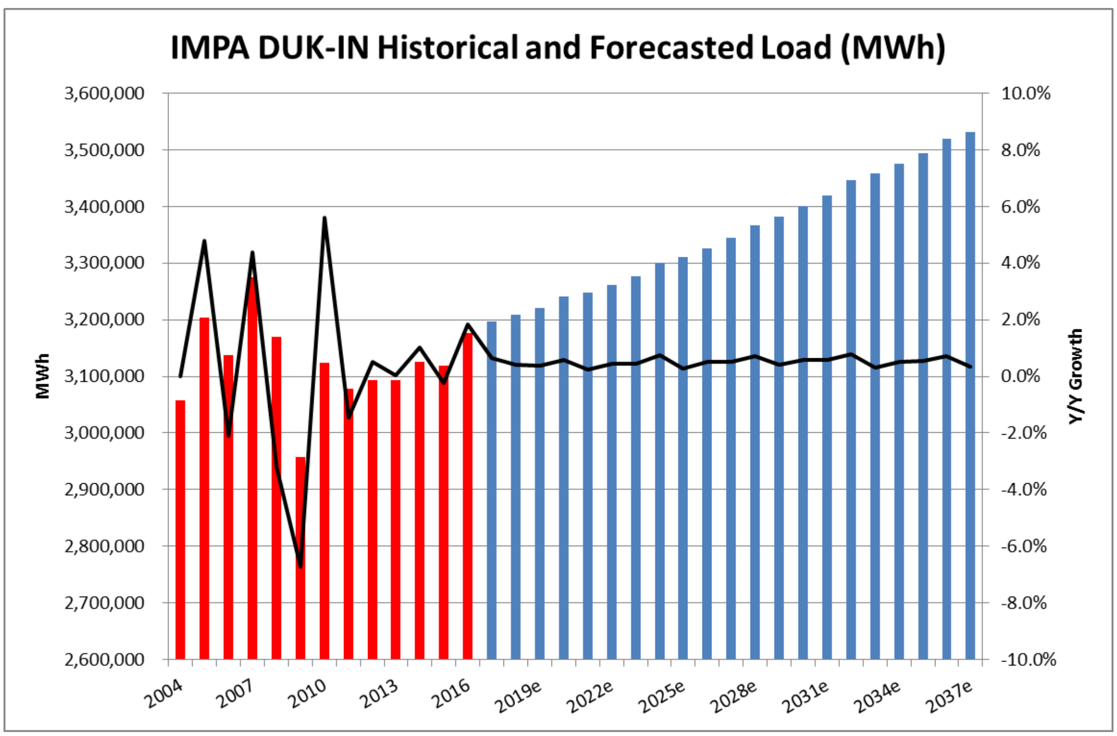
GDP Survey Data										
Year/Provider	OECD	CBO	IMF	EIU	World Bank	UN	Average/Median	Applied Growth Rate	Monthly Growth Rate	Quarterly Growth
2017	2.27%	2.32%	2.30%	2.30%	2.20%	2.00%	2.29%	2.16%	0.1782%	0.535%
2018	3.0%	2.01%	2.50%	2.10%	2.10%	2.00%	2.10%	2.10%	0.1733%	0.521%
2019	2.64%	1.71%		1.00%	1.90%		1.81%	1.81%	0.1493%	0.448%
2020	2.57%	1.54%		2.00%			2.00%	2.00%	0.1652%	0.496%
2021	2.51%	1.77%		2.00%			2.00%	2.00%	0.1652%	0.496%
2022	2.48%	1.89%					2.18%	2.18%	0.1801%	0.541%
2023	2.45%	1.91%					2.18%	2.18%	0.1798%	0.540%
2024	2.42%	1.92%					2.17%	2.17%	0.1788%	0.537%
2025	2.40%	1.90%					2.15%	2.15%	0.1773%	0.533%
2026	2.38%	1.89%					2.13%	2.13%	0.1760%	0.529%
2027	2.37%	1.88%					2.12%	2.12%	0.1751%	0.526%
2028	2.36%						2.36%	2.36%	0.1942%	0.584%
2029	2.33%						2.33%	2.33%	0.1919%	0.577%
2030	2.28%						2.28%	2.28%	0.1880%	0.565%
2031	2.23%						2.23%	2.23%	0.1840%	0.553%
2032	2.18%						2.18%	2.18%	0.1802%	0.542%
2033	2.14%						2.14%	2.14%	0.1764%	0.530%
2034	2.09%						2.09%	2.09%	0.1724%	0.518%
2035	2.04%						2.04%	2.04%	0.1686%	0.507%
2036	1.99%						1.99%	1.99%	0.1647%	0.495%
2037	1.95%						1.95%	1.95%	0.1609%	0.483%

5.5 BASE LOAD FORECAST RESULTS

Energy Forecasts

Using the process outlined above, the following figures depict historical loads against forecasted loads, in addition to forecasted load for the next 20 years. The primary Y axis shows the actual and forecast energy use (red and blue columns) while the secondary Y axis shows actual and forecast year over year growth rates (black line).

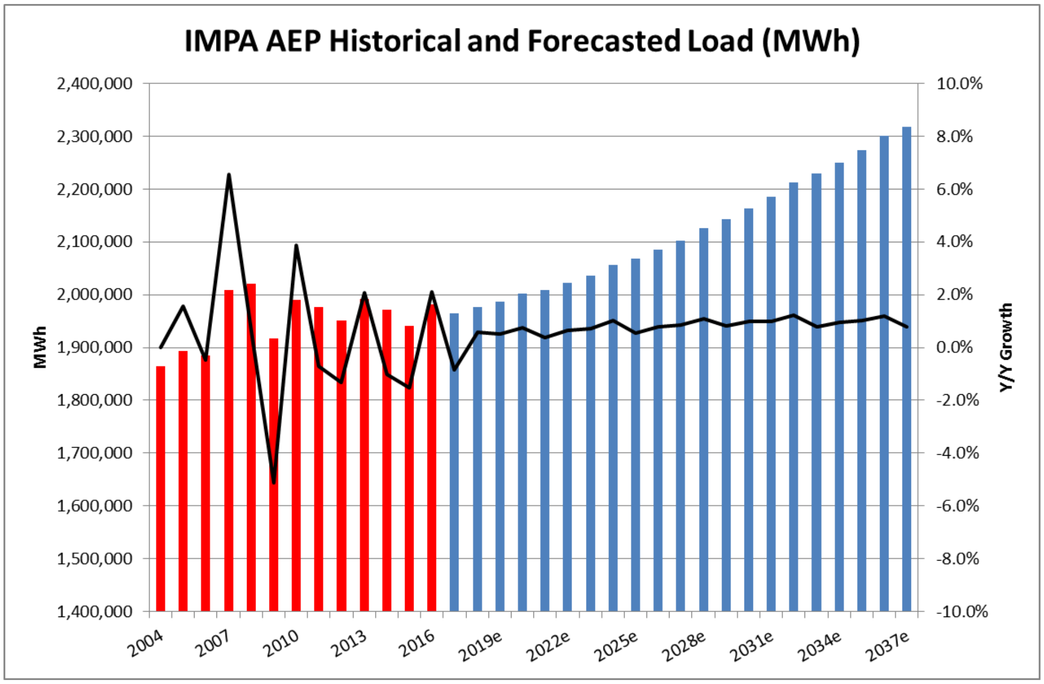
Figure 5 IMPA DUK-IN Historical and Forecasted Load



For the DUK-IN load zone, load growth is expected to average around .5% growth per year over the next 20 years, well below consensus economic growth rates. This growth is driven in the model by the assumption that weather patterns remain in a 20 year "normal" (i.e., average) range for both heating and cooling demand, in addition to a decreasing energy intensity of the economy. That is, it is expected that the energy requirement to produce $1 of real GDP growth is expected to decline in the coming years.

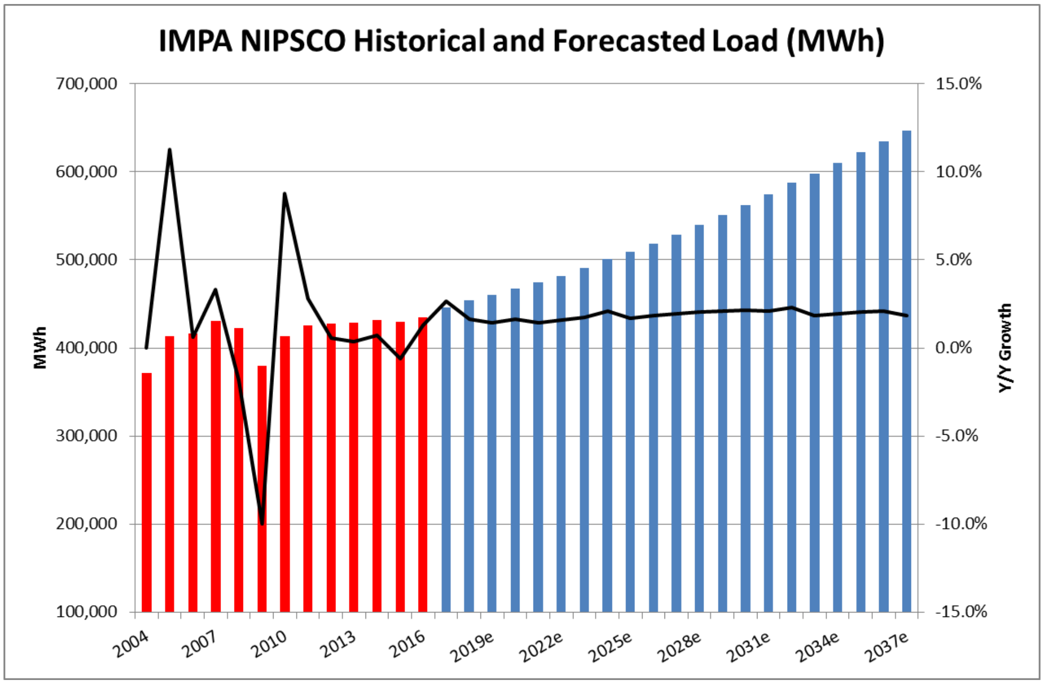
For IMPA's AEP load zone, load growth also remains muted on declining energy intensity and relatively muted economic growth. Load growth for the AEP zone is expected to grow at around .75% per year on average over the forecast period.

Figure 6 IMPA AEP Historical and Forecasted Load



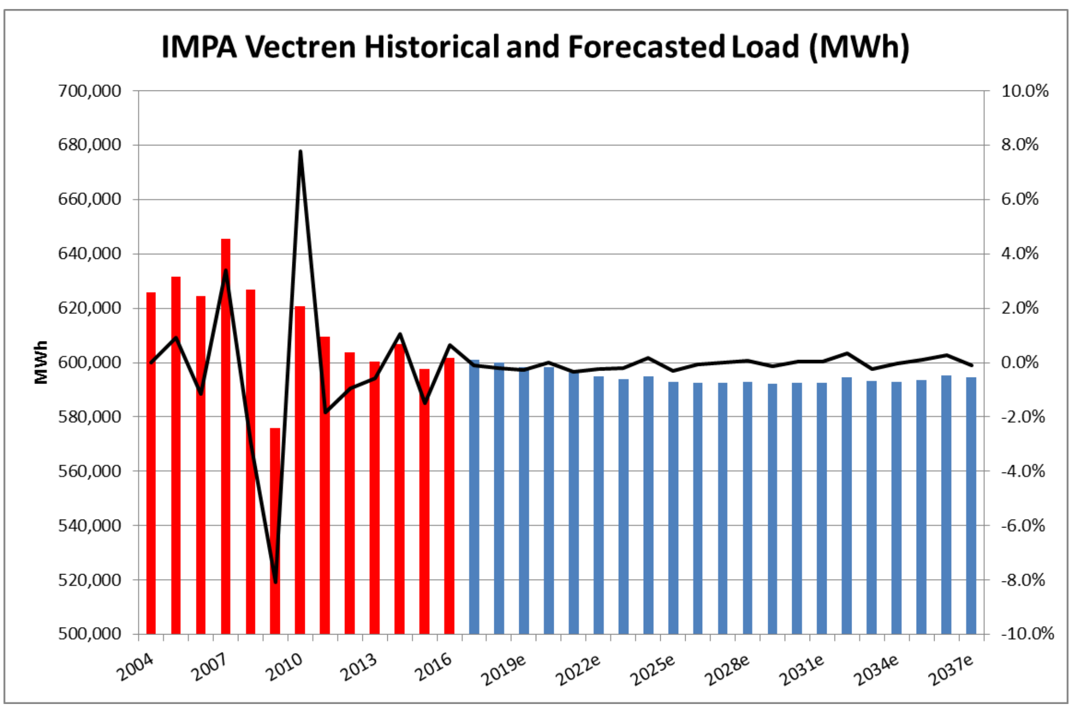
In contrast to IMPA's other load zones, the NIPSCO load zone is expected to grow at a rate closer to consensus economic forecast growth (1.8%) and more in line with the broader economy perhaps owing to its geographical proximity to industrialized Northwest Indiana and Chicago.

Figure 7 IMPA NIPSCO Historical and Forecasted Load



Offsetting the growth seen in the NIPSCO load zone is the contracting growth in the Vectren load zone forecast.

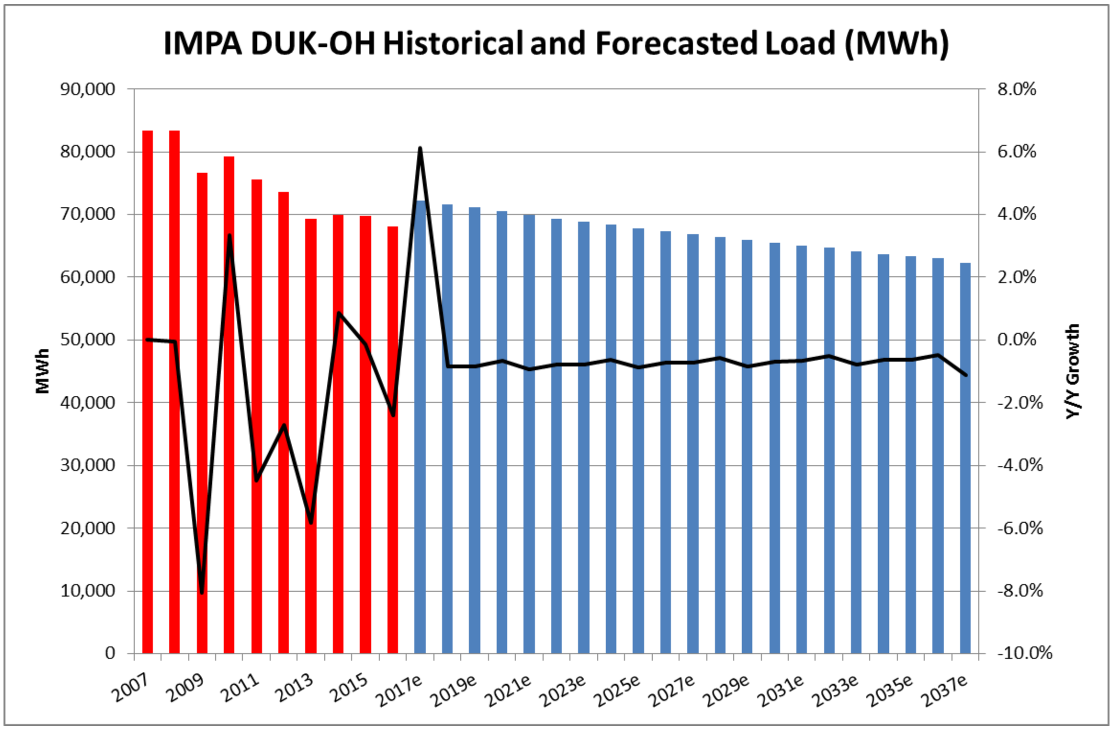
Figure 8 IMPA Vectren Historical and Forecasted Load



The energy forecast for Vectren is more sensitive to local economic drivers (e.g., Indiana Non-Farm Payrolls) than national economic drivers. Historically, payroll growth in Indiana lags behind national economic growth. Statistically, 2.1% real GDP growth is expected to lead to a .9% increase in Indiana Non-Farm Payrolls, a statistically significant driver of load growth in the Vectren area. Vectren load growth is expected to average a .05% decline over the forecast period.

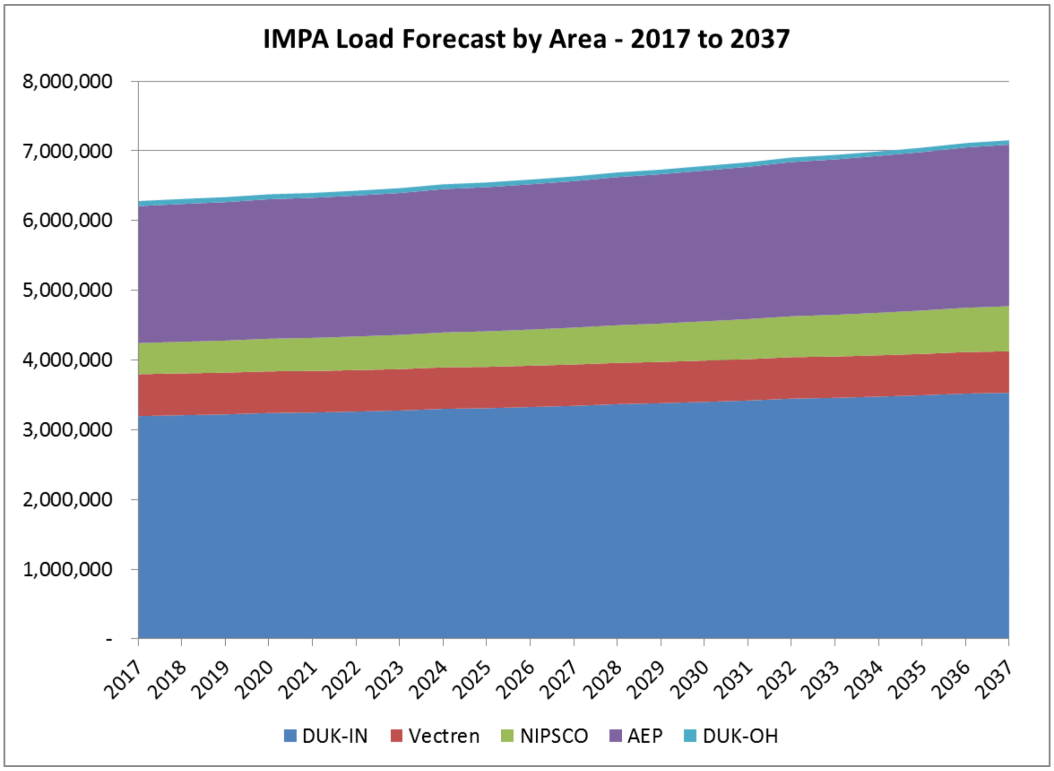
Finally, IMPA's smallest load zone, DUK-OH, exhibits similar annual declines in growth due primarily to factors related to declining energy intensity of economic output, averaging a .74% decline.

Figure 9 IMPA DUK-OH Historical and Forecasted Load



When combined into a single load, IMPA is expected to see load growth average a .6% compound annual growth rate (CAGR) over the next 20 years with DUK-IN, NIPSCO, and AEP being areas expected to experience growth while Vectren and DUK-OH are expected to contract somewhat. Illustrated on the basis of total annual energy, the respective load areas are show below.

Figure 10 IMPA Load Forecast by Area



The following table illustrates the energy and demand forecasts. The IMPA Peak Demand figures are the simple sum of the area peaks and do not take into account area coincidence which is handled in the production model. As with any forecast, the estimate is subject to uncertainty and error. The monthly forecast error for energy is +/- 14,000 MWh and error for peak demand is +/- 20 MW. This forecast error does not include the variability around the forecast errors of the input variables.

Table 11 Energy and Demand Forecasts

Year	*IMPA Total Energy (MWh)*	*IMPA Peak Demand (MW)*
2018	6,311,281	1,188
2019	6,337,351	1,190
2020	6,378,312	1,195
2021	6,397,403	1,198
2022	6,429,876	1,202
2023	6,465,882	1,205
2024	6,521,460	1,213
2025	6,548,214	1,216
2026	6,589,682	1,221
2027	6,634,295	1,227
2028	6,691,485	1,234
2029	6,732,188	1,239
2030	6,784,646	1,246
2031	6,837,249	1,252
2032	6,905,850	1,262
2033	6,942,487	1,265
2034	6,992,628	1,272
2035	7,047,281	1,279
2036	7,113,103	1,288
2037	7,153,263	1,292
2038	7,194,011	1,297

In addition to statistical uncertainty in the underlying forecasts, IMPA also prepared forecasts assuming varying rates of economic growth, as measured by real GDP. Under the low growth scenario, IMPA assumed long term real GDP growth of 1.5% per year, under current consensus estimates of roughly 2.3%. Under the high growth scenario, IMPA assumed growth that averaged 2.6% over the 20 years, which corresponds to the high end of consensus estimates at the time the forecast was developed. The following figures illustrate the expected forecast, along with these two scenario impacts on the expected load forecast.

Figure 11 IMPA Load Forecast Comparisons

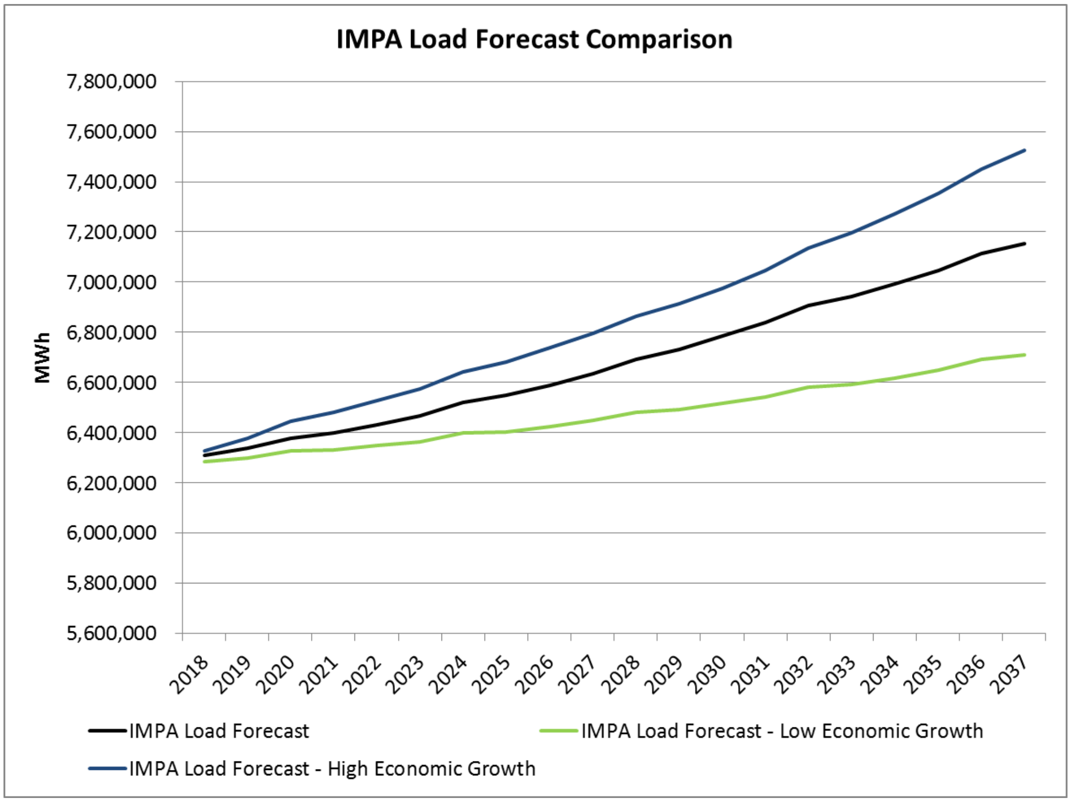
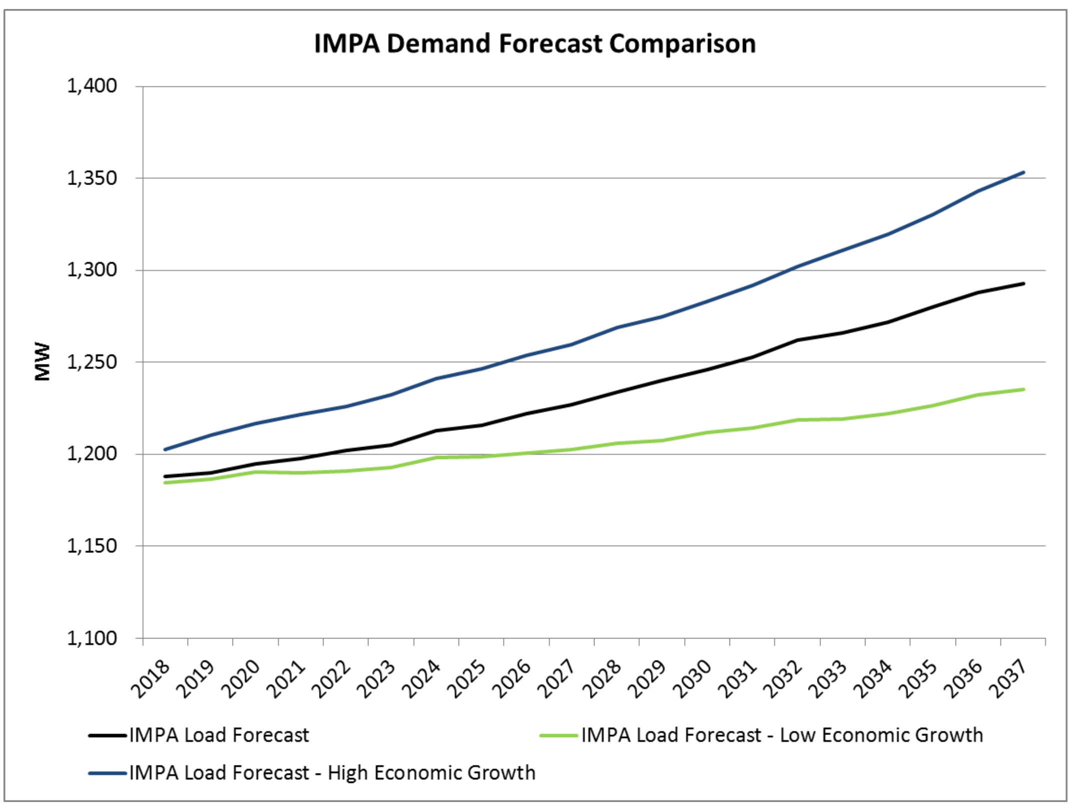


Figure 12 IMPA Demand Forecast Comparisons



5.6 Load Forecast Model Performance

The following figures compare the IMPA peak demand and energy forecasts used in the last five IRPs with actual results.

Figure 13 Load Forecast Performance – Peak Demand

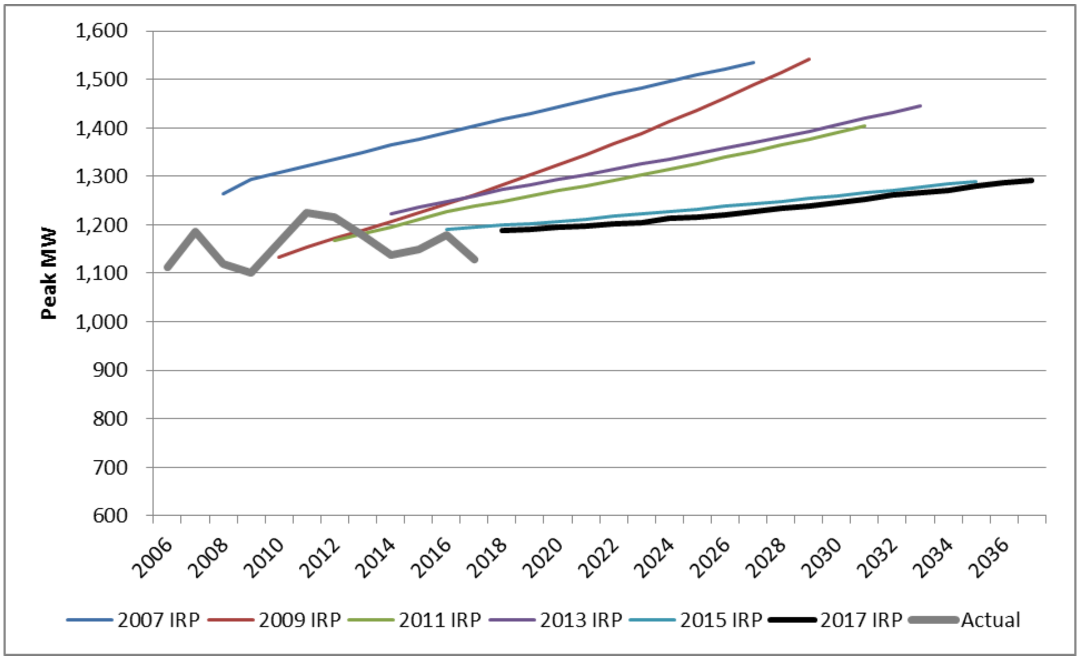
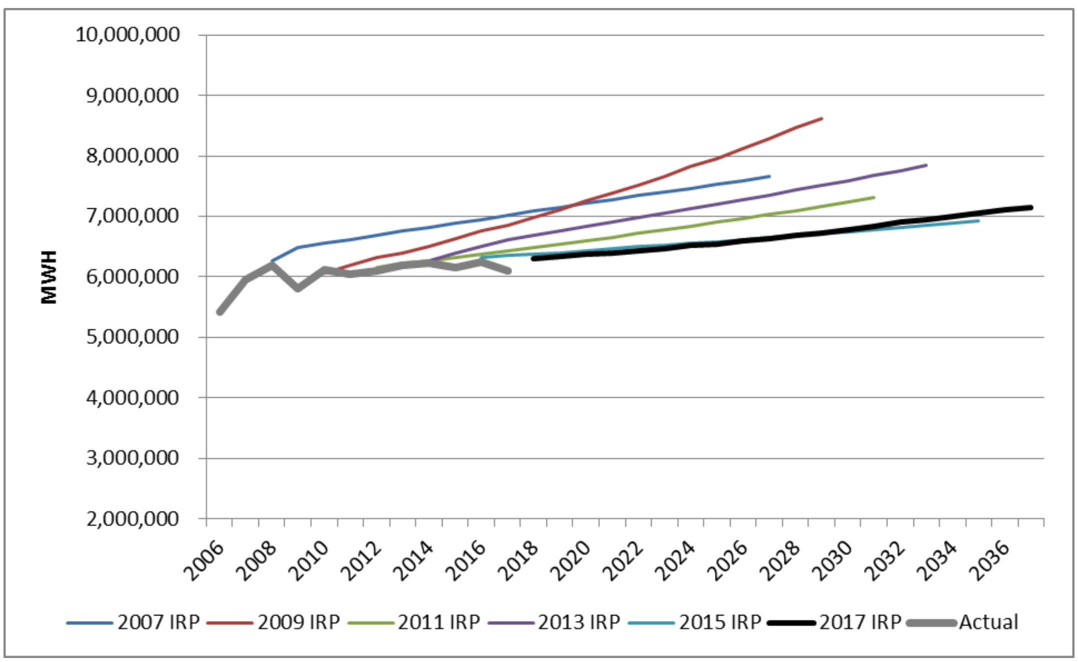


Figure 14 Load Forecast Performance – Energy Requirements



5.7 ALTERNATE LOAD FORECAST METHODOLOGIES

Rate Classification/Sector Methodology

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 61 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.

End-Use Methodology

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. Given the fact that IMPA would need to sample a substantial portion of its members' retail consumers to achieve a statistically valid sample, end use sampling is unreasonable for IMPA to implement. Therefore, IMPA cannot realistically utilize this type of a forecast model.

6 RESOURCE OPTIONS

6.1 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. 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, solar 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 large generation 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 undivided ownership interests in Gibson 5, Trimble County 1 and 2, Prairie State 1 and 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 the jointly-owned coal units that could increase their output capability. IMPA's generating member 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.

All IMPA-owned units were given the opportunity to retire in the capacity expansion runs. In the production model, these decisions are made during the zonal capacity expansion run. In this way, IMPA is not "retiring" only its share of a joint owned resource, but the entire resource is removed from the system.

If an IMPA unit is retired, all future capital expenditures and operating costs are removed, however, any bond obligations associated with the facility remain. When a unit is retired it is assumed the decommissioning expense is equal to the salvage value.

New Resources

The purpose of an IRP is to assist the company in determining its future generation requirements at a basic needs level, not to select the specific unit type and model. The selection of the actual brand and model to construct would be determined in the bid and project development process.

The traditional, thermal generating resources considered in this study include:

- Advanced combined cycle (CC) units
- Advanced gas-fired combustion turbines (CT)
- Aero-derivative combustion turbine
- Coal-fired steam generation
- High efficiency internal combustion (IC) units
- Nuclear

Capital cost, fixed and variable cost and operating assumptions were sourced from "Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2016" from the U.S. Energy Information Administration.

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 undergoes an environmental review prior to the beginning of construction and that the potential resource complies with any environmental constraints. If 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 and Bi-Lateral Capacity Purchases

Current market prices are extremely competitive with new capacity resource costs for the next 10 years. IMPA provided the modelling system with the option to select market based alternatives through 2025. These alternatives were based on actual offers received by IMPA and the current forward curves. Generally speaking, these products compare favorably to new capacity from both a nominal dollar standpoint and a risk standpoint.

Energy Markets

IMPA participates in both the MISO and PJM markets for balancing capacity and short-term purchases/sales. While market products were included in the model for near term requirements, IMPA does not believe it is prudent to rely solely on these RTO capacity and energy markets to meet its long-term capacity and energy requirements. However, reserve margin flexibility is allowed in order to allow for load uncertainty, energy efficiency and renewable development.

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

6.2 Renewable Options

In addition to the traditional resources discussed above, the expansion model was allowed to select from a variety of renewable resources as well. The renewable alternatives included in the expansion analysis are shown below.

- Utility Scale Wind
- Utility Scale Photovoltaic (PV) Solar

Pricing for all of the renewable alternatives was based on the aforementioned EIA data, IMPA's experience in constructing facilities, indicative market quotes from renewable energy providers and industry documentation of installed and operating costs.

See Appendix E for detailed expansion unit data.

IMPA is in the process of developing solar park projects. The current plan assumes continued development of community based solar parks over the next ten years in addition to the 36.7 MW already developed, totaling approximately 150 MW. Additional renewable energy additions were left up to the expansion and portfolio optimization models to determine.

6.3 Demand-Side Options

IMPA's goal is to provide low cost, reliable, and environmentally-responsible electric power to its members. IMPA accomplishes this by maintaining a diverse set of energy resource options along with its existing energy efficiency program.

Since the Energizing Indiana program ended in 2013, the IMPA energy efficiency program has been the primary vehicle used to provide energy efficiency options to IMPA member's retail customers. The program is a prescriptive rebate system providing incentives for the installation of a dozens of items. Incentives are available for both residential and C&I customers.

Residential Incentive Measure Groups

- Central Air Conditioner >16 SEER
- Air to Air Heat Pump >16 SEER
- Geothermal Heat Pump
    - Open Loop >17.1 SEER
    - Closed Loop >21.1 SEER

Commercial and Industrial Incentive Measure Groups

- Variable Frequency Drive Pumps and Motors
- Heating Ventilation and Air Conditioning
- Refrigeration, Food Service and Controls
- C&I Lighting
    - CFL
    - LED
    - Occupancy Sensors

Both measures and incentive amounts are reviewed periodically to determine additions, deletions or modifications to incentive payments.

A full listing of all eligible items and incentives can be viewed at:
www.impa.com/MediaLibraries/IMPA2017/Energy-Efficiency-Program/EE-Brochure-2017.pdf

Since 2014, the IMPA energy efficiency program has paid incentives in excess of $425,000 creating a cumulative savings of approximately 14,850 MWh and 2 MW. Interestingly, this 14,700 MWh of annual savings is larger than the total annual energy requirements of 20 of IMPA's 61 members.

Going forward, the IMPA energy efficiency program will continue to be IMPA's primary method of offering energy efficiency services to member communities.

7 ENVIRONMENTAL

7.1 COMPLIANCE WITH CURRENT RULES

The majority of IMPA's current resources are not substantially impacted by the EPA's rules slated to go into effect in the next few years. The following sections describe compliance actions IMPA expects to be taken at its generating facilities in connection with environmental rules.

General

The Cross State Air Pollution Rule and The Cross State Air Pollution Update Rule

In July 2011, the EPA finalized the CSAPR, limiting the interstate transport of emissions of NO_x and SO_2 that contribute to harmful levels of particulate matter and ozone in downwind states. CSAPR requires 28 states in the eastern United States to reduce SO_2, annual NO_x and ozone season NO_x emissions from fossil fuel-fired power plants. After much litigation, Phase 1 of CSAPR's emissions trading programs began in January 2015 for the annual programs and May 2015 for the ozone season program. Phase 2 began in January 2017 for the annual programs and May 2017 for the ozone season program.

In October 2016, the EPA finalized an update to CSAPR for the 2008 ozone National Ambient Air Quality Standards (NAAQS) by issuing the final CSAPR Update Rule. The new rule started in May 2017 to reduce summertime (May – September) NO_x emissions from power plants in 22 states in the eastern United States. Litigation challenging the rule continues and administrative petitions for reconsideration of the rule have been filed. However, the administration has not yet acted on the petitions. IMPA has made significant investments to install environmental control equipment to comply with SO_2 and NO_x requirements including CSAPR. IMPA expects that the Agency will also have to acquire a small percentage of its overall SO_2 and NO_x emission allowances needed for compliance, but that there will be no further material impacts on IMPA's generating facilities.

The Mercury and Air Toxics Standards

EPA issued the Mercury and Air Toxics Standards (MATS) in March 2011 to regulate emissions of hazardous air pollutants (HAPs) from electric generating units greater than 25 MW. The rule was initially challenged in 2012, but the U.S. Court of Appeals for the D.C. Circuit (D.C. Circuit) determined that MATS was reasonable and upheld the rule. Opponents of MATS appealed the ruling to the U.S. Supreme Court, which held in June 2015 that the EPA had acted unreasonably by failing to consider the costs of compliance in determining that it is appropriate and necessary to regulate HAPs from coal and oil-fired power plants and remanded the case back to the D.C. Circuit. In April 2016, EPA issued a final finding that even when considering costs, it is still appropriate and necessary to set standards for emissions of air toxics from coal and oil-fired power plants. In April 2017, the D.C. Circuit granted EPA's request to delay the oral arguments on MATS as the administration reviews the rule. All of IMPA's units comply with MATS as it currently exists. IMPA does not expect there to be any material changes to MATS that would cause more capital additions.

Coal Combustion Residuals Rule

In October 2015, the CCR rule to regulate the disposal of coal ash as nonhazardous waste from coal-fired power plants under subtitle D of the Resource Conservation and Recovery Act (RCRA) came into effect. The rule establishes nationally applicable minimum criteria for the safe disposal of coal combustion residuals in CCR landfills, CCR surface impoundments and all lateral expansions of CCR units. It applies to new and existing facilities. Under RCRA's framework, the CCR rule could only be enforced via citizen suits. However, federal legislation passed in December 2016 allowed states to design a coal ash permit program that will then be approved by the EPA. Gibson generating unit has a completed landfill in use while the Trimble County generating units are in the process of developing a landfill adjacent to the units on station property. These operations consist of dry storage in lined landfills. WWVS disposes its CCR at an offsite third party facility. Prairie State's facilities were constructed with lined landfills for dry disposal and as such will not be impacted by this rule.

Clean Power Plan

In August 2015, the EPA finalized the CPP, which seeks to reduce carbon dioxide emissions from electric generating units by 32 percent from 2005 levels by 2030. In February 2016, the U.S. Supreme Court issued a stay of the CPP, allowing the D.C. Circuit to review challenges to the rule. In May 2017, the EPA petitioned the D.C. Circuit to indefinitely suspend litigation over the CPP, which the court granted. In October 2017 the EPA issued a proposed rule to repeal the CPP with comments due in April 2018. In December 2017, EPA published an advanced notice of proposed rulemaking for a rule to replace the CPP. IMPA anticipates that its generating units would be affected by a replacement rule aimed at reducing carbon emissions, but when and to what degree depends on the final rule.

Effluent Limitation Guidelines

In September 2015, the EPA finalized its Effluent Limitation Guidelines (ELG) impacting steam generating units that discharge to surface waters and publicly owned treatment works (POTW). With compliance dates fast approaching, in April 2017 the EPA granted a request to reconsider the rule and the U.S. Court of Appeals for the Fifth Circuit granted EPA's motion to hold some of the ELG litigation in abeyance pending the EPA's reconsideration of the rule. Other challenges to the ELG rule remain subject to litigation. Since then, EPA finalized a rule postponing certain compliance dates by two years for the ELG rule. The ELG rule will impact Trimble County, as well as the Whitewater Valley Station. The ELG rule will have minimal to no effect on Gibson 5 and Prairie State as they have no discharges. Whitewater Valley Station is designing and will implement process modifications to eliminate the small discharges from the facility to the POTW. An existing pond will be modified to hold and recirculate the ash contacted water.

Final Ozone National Ambient Air Quality Standards

On October 2015, EPA revised its NAAQS for ground-level ozone to 70 parts per million (ppm), down from the 2008 standard of 75 ppm. Under the 2015 ozone NAAQS, states will be required to develop and put in place pollution control plans for counties found to be in "non-attainment" with the limit. On June 6, 2017, the EPA extended the deadline for promulgating initial area designations for the NAAQS 2015 ground-level ozone standard, until October 2018. IMPA does not yet know the full impacts of this standard on its generating units.

Waters of the United States

The Army Corps of Engineers and EPA issued the final Waters of the United States (WOTUS) rule in May 2015, which redefined which streams, wetlands and other bodies of water are protected by the Clean Water Act. The rule went into effect in August 2015, but the U.S. Court of Appeals for the Sixth Circuit ordered a nationwide stay of the rule in October 2015. However, on January 22, 2018, the United States Supreme Court decided that challenges to WOTUS must go through the federal district court level rather than going straight through to the circuit court level. Therefore, the Sixth Circuit must dismiss petitions to review WOTUS for lack of jurisdiction. As a result, the Sixth Circuit's nationwide stay is no longer applicable. Meanwhile, the EPA and the Army Corps of Engineers are in the process of finalizing a rule to delay the applicability date of WOTUS, which would afford the agencies time to complete a two-step rule process to repeal and replace WOTUS.

Since all of IMPA's units are equipped with cooling towers and lakes, the units do not directly discharge into jurisdictional waters. Therefore, IMPA is not aware of any effects this rule has on its units, but will continue monitoring the rule for future effects.

Gibson #5

Gibson #5 currently complies with the SO_2, 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 CSAPR NO_x and SO_2 regulations. IMPA's share of the SO_2 and NO_x emissions allowances allocated by the EPA and the Indiana Department of Environmental Management (IDEM) will satisfy most of IMPA's requirements for such allowances.

Gibson 5 complies with the annual and seasonal requirements of the NO_x rule by operating its SCR system on an annual basis. Gibson 5 will likely need to purchase a small number of allowances for SO_2 and NO_x allowances in future compliance periods.

Gibson 5 is affected by the MATS Rule and required upgrades in April 2016 for compliance. The electrostatic precipitator was upgraded and a calcium bromide injection system was added.

Non-hazardous solid waste from this bituminous coal fired unit consists of the following CCRs: 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 surface impoundments at the site. DEI also actively pursues other alternative reuse of CCRs.

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

Trimble County 1 currently complies with the SO_2, NO_x, particulate matter, and opacity requirements of the Clean Air Act.

Trimble County 1 complies with the CSAPR NO_x rules by operating with low NOx burners and the SCRs on an annual basis. IMPA expects its share of allowances to satisfy the most of the NO_x emissions at Trimble County.

Compliance with the CSAPR SO_2 rule is accomplished through the operation of the Trimble County 1 FGD system. IMPA expects its share of allowances to satisfy the CSAPR SO_2 emissions of Trimble County 1.

Solid waste from the bituminous coal consumed in the unit consists of the following CCRs: fly ash, bottom ash, and gypsum from the SO_2 scrubber. The solid waste is disposed of in a surface impoundment on the site or beneficially reused by marketing the CCRs to third parties. LG&E is currently developing a solid waste disposal facility for dry disposal of future CCR adjacent to the station. Additionally, LG&E actively pursues alternative reuse of CCRs.

Trimble County 1 is affected by the MATS rule, and it uses sorbent injection and a pulse jet fabric system that was installed in late 2015 for compliance.

Any hazardous waste generated at Trimble County is analyzed to confirm the hazardous nature and then profiled with LG&E'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

As with Trimble County 1, compliance with CSAPR is required. Trimble County 2 will comply in the same fashion as Trimble County 1. Its allocation of NO_x and SO_2 allowances are adequate to cover its emissions.

Trimble County 2 is subject to the MATS rule and is fully equipped for compliance.

Solid waste from the bituminous and sub-bituminous coal consumed in the unit consists of the following CCRs: fly ash, bottom ash, and gypsum from the SO_2 scrubber. The solid waste is disposed of in a surface impoundment on the site or beneficially reused by marketing the CCRs to third parties. LG&E is currently developing a solid waste disposal facility for dry disposal of future CCR adjacent to the station. Additionally, LG&E actively pursues alternative reuse of CCRs.

Any hazardous waste generated at Trimble County is analyzed to confirm the hazardous nature and then profiled with LG&E'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.

Prairie State Energy Campus

Prairie State Units 1 and 2 are subject to CSAPR. The Prairie State units receive CSAPR NO_x and SO_2 allowances from Illinois' new unit set aside which meet most of its emission requirements. Any remaining allowances that are needed for compliance will be purchased along with all the required SO_2 allowances required for compliance with the Title IV Acid Rain program.

The Prairie State units are subject to the MATS rule and are fully equipped for compliance.

Solid waste from these mine-mouth bituminous coal fired units consists of the following CCRs: fly ash, bottom ash, and gypsum from the SO_2 scrubber. The solid, dry waste and breaker waste from the mine is disposed at the near-field landfill. PSGC actively pursues alternative reuses of CCRs.

Hazardous waste generation at Prairie State is similar to Gibson Unit 5 and Trimble County. All hazardous wastes generated by Prairie State 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.

Whitewater Valley Station

WWVS currently complies with the SO_2, NO_x, particulate matter, and opacity requirements of the Clean Air Act. WWVS complies with the CSAPR NO_x rules using low NOx burners and overfire air. IMPA expects its share of allowances to satisfy the NO_x and SO_2 emissions at WWVS. Solid waste from the bituminous coal consumed in the unit consists of the following CCRs: fly ash and bottom ash. The solid waste is disposed of in a private offsite facility, the mine from one of the fuel suppliers. IMPA discontinued use of the surface impoundment as part of its plan for compliance with the CCR Rule.

WWVS is affected by the MATS rule, and is fully equipped for compliance. A pulse jet fabric filter was installed in the 2010 time period and new sorbent and powder activated carbon injection systems were installed in late 2015 for compliance with the MATS Rule.

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. WWVS normally operates as a Small Quantity Generator (<1000 kg per month). All hazardous wastes generated at WWVS 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.

IMPA Combustion Turbines

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 and/or water injection for NO_x control. The stations meet CSAPR NO_x 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.

The Anderson and Richmond turbines can operate on pipeline natural gas or No. 2 ultra-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. Infrequently, oily waste may be removed from collecting tanks located at 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 be, at infrequent times, oily waste removed from onsite collecting tanks. This waste is also disposed of using properly licensed vendors.

7.2 Compliance with Future Rules

IMPA makes no assumptions as to future environmental rules or laws. For purposes of this analysis, it is assumed that all future resource options comply with the existing environmental rules in place at the time of installation.

7.3 Renewable Energy and Net Metering

IMPA's current renewable energy sources consist of a 48 MW wind contract and 36.7 MW of solar facilities.

Since 2009, the Crystal Lake wind contract has supplied approximately 2.5% of IMPA's annual energy requirements.

IMPA solar parks are currently operating in the following communities:

Table 12 IMPA Solar Parks

Community	MW
Anderson 1	5.0
Anderson 2	8.1
Argos	0.7
Bainbridge	0.4
Crawfordsville	3.0
Flora	0.8
Frankton	1.0
Greenfield	2.8
Huntingburg	2.1
Pendleton	2.0
Peru	3.0
Rensselaer	1.0
Richmond	1.0
Spiceland	0.5
Tell City	1.1
Washington	3.9
Waynetown	0.3

Anderson 1 and 2, Greenfield, Flora and Spiceland were planned and constructed by IMPA, but sold to third-parties. IMPA purchases 100% of the output from these solar parks under long term PPAs with the third-parties.

As stated previously, IMPA's net metering program is implemented at the member level at the member's discretion. At this time, IMPA members have approximately 20 customers participating in net metering programs. In addition to net metered customers, IMPA has contracts with three customers with renewable systems larger than IMPA's net metering maximum. IMPA purchases the excess generation output if it exceeds the customer's onsite load requirements.

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8 TRANSMISSION AND DISTRIBUTION

8.1 FUTURE TRANSMISSION ASSUMPTIONS

As noted previously, IMPA is a member of MISO as a TO within the DEI area and is a TDU within the NIPSCO and Vectren areas. 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 load zone, DEI performs any additional transmission system planning functions on behalf of the three owners of the JTS. IMPA participates in the joint owners' Planning Committee, which reviews major system expansions planned by DEI, with DEI taking responsibility for filing the FERC Form 715 on behalf of the JTS (see Appendix G for a statement regarding Form 715). IMPA assists its members where needed in determining when new or upgraded delivery points are required and coordinates any studies, analyses or upgrades with other utilities.

Rates for MISO and PJM area-specific NITS and ancillary services were escalated to reflect increased cost for transmission service over the study period. Additionally, costs for PJM's Transmission Enhancement Charge, MISO's Network Upgrade Charge (Schedule 26) and Multi Value Project Charge (MVP) adder (Schedule 26a) were increased based on projections provided by the RTOs. This reflects the increases in these charges due to the construction of new transmission projects over the next decade.

Each year, IMPA pays a significant amount of money for RTO congestion and losses. IMPA, along with consultants and the RTOs, has investigated methods by which IMPA could invest in transmission improvements as another way to help mitigate congestion risk at some of its resource Commercial Pricing Nodes (CPNODES). At this time, no economic upgrades have been found, but IMPA continues to research viable projects.

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9 SOFTWARE OVERVIEW / DATA SOURCES

IMPA utilizes the AuroraXMP by EPIS, Inc., MCR-FRST by MCR Performance Solutions, LLC and various custom made risk analysis tools to perform its resource planning studies.

9.1 AURORAXMP

AuroraXMP is a fully integrated planning model that allows the user to generate market capacity expansion studies, market price studies and portfolio optimization in the same platform utilizing the same database. By not having to move data between independent modules, both time and accuracy are improved over other available models.

9.2 MCR-FRST

MCR-FRST by MCR Performance Solutions, LLC is a financial model IMPA utilizes to develop the final revenue requirements for its portfolio. MCR-FRST takes operational outputs from AuroraXMP and combines them with other operational and financial inputs to create IMPA's annual revenue requirements.

9.3 RISK ANALYSIS TOOLS

To assess the risk of the various plans, IMPA utilizes a variety of analytical tools and techniques. Among these are decision trees, risk profiles, tornado charts, and trade-off diagrams. When selecting a preferred plan, strong consideration is given for the robustness of the plan in addition to the relative cost, rate impact, and potential risk of the plan.

9.4 External Data Sources

IMPA's database uses a mix of publicly available forecasted information and IMPA proprietary information from a variety of sources.

Table 13 External Data Sources

Source Title	Publishing Address
Annual Energy Outlook 2016 & 2017	U.S. Energy Information Administration Office of Communications, EI-40 Forrestal Building, Room 1E-210 1000 Independence Avenue, S.W. Washington, DC 20585
Velocity Suite Database	Ventyx 1495 Canyon Blvd, Suite 100 Boulder, CO 80302
S&P Global Market Intelligence; SNL Energy Data	SNL Financial LC PO Box 2124 Charlottesville, Virginia 22902
Planning Year 2017-2018 LOLE Study	Midcontinent ISO (MISO) 701 City Center Drive Carmel, IN 46032
2016 Long-Term Reliability Assessment	North America Electric Reliability Corporation (NERC) 3353 Peachtree Road NE, Suite 600 North Tower Atlanta, GA 30326
JD Energy's Forecasting Services	JD Energy PO Box 1935 120 Fairview Avenue Frederick, MD 21702-0935
U.S. EPA Clean Power Plan for Existing Power Plants	U.S. Environmental Protection Agency 1200 Pennsylvania Avenue, N.W. Washington, DC 20460
PJM Long Term Load Forecast- 2017	PJM Interconnection 2750 Monroe Boulevard Audubon, PA 19403

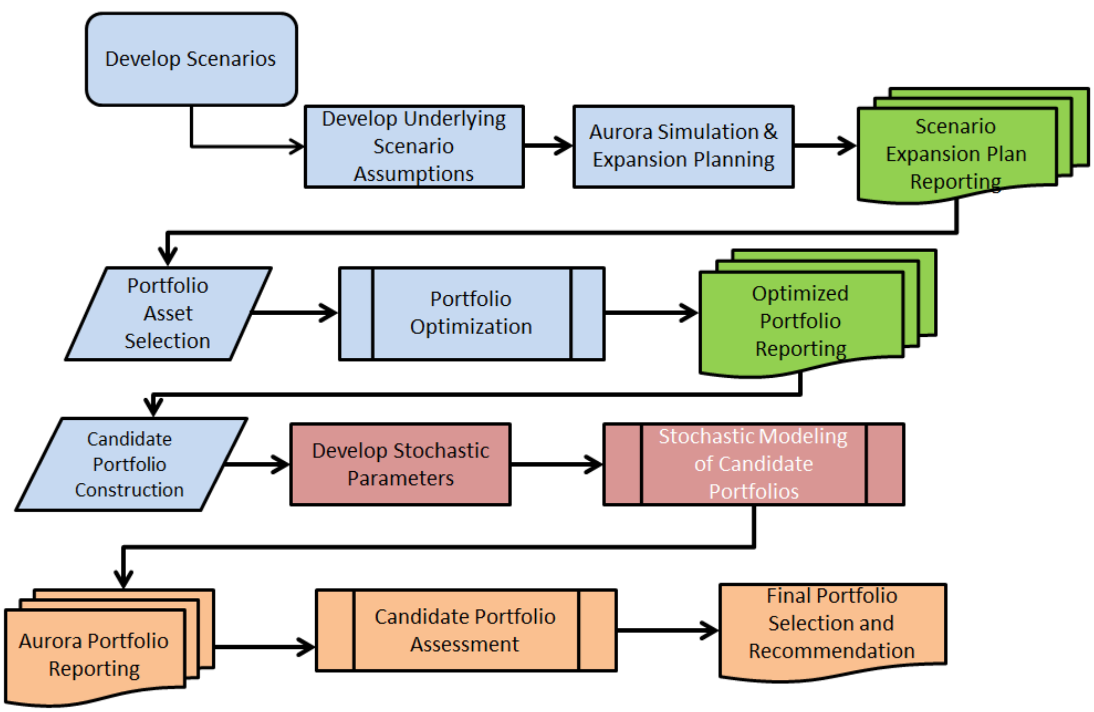
10 SCENARIO DEVELOPMENT

IMPA creates scenarios as a way to think about the future. Scenario planning is a proven tool to better anticipate and respond to future risks and opportunities. IMPA develops stories about how the future might unfold by building alternate views of the future given different economic, regulatory or technological assumptions.

10.1 IRP Scenario Process

A key aspect of scenario planning for an electric utility is to transform the scenario narrative into electricity market characteristics that can be incorporated into the IRP process. These characteristics are then incorporated into the long term market model. This essentially involves developing a long term capacity expansion for the entire eastern region. The scenarios can significantly affect the type and timing of resource additions, and thus, long term capacity and energy prices. Ideally these scenarios and their expansion serve as "book-ends" that examine a variety of outcomes.

Figure 15 IRP Flowchart



10.2 Scenario Themes

For the 2017 IRP, IMPA identified three distinct themes which are expected to have the greatest impact on the future energy business environment over the next 20 years. IMPA looks to forward markets as much as reasonably possible as an unbiased predictor of likely future events. Deviations from forward market expectations are expected to evolve over time in each scenario.

Figure 16 Case Overview

Case Comparison			
Drivers	***Robust Growth/De-regulation***	***Base Case***	***Green Case***
Economic Growth	2.6%	2.1%	1.5%
Capital Costs	Reference	Reference	Reference
Load Forecast	IMPA Reference +3.2%	IMPA Base Case	IMPA Reference -3.3%
Natural Gas Prices	Reference +32%	Reference	Base +35% (on average)
Coal Price	Reference +6%	Reference	Reference +2%
CO2 Policy	None	\$20/Ton in 2026	\$40/Ton in 2026
RPS	No	No	20% by 2030 w Phase In
Reserve Margin	15%	15%	15%

Robust Growth/Deregulation

- **Near Term (2018-2023)**
  - Slightly Higher Natural Gas Prices
  - Higher GDP Growth translates into higher load growth
  - Federal Incentives for Renewables Sunset as planned
- **Medium/Long Term (2024 and Beyond)**
  - No Carbon Legislation
  - Zero incentives for renewable technologies
  - New Coal Builds Permitted

Base Case

- **Near Term (2018-2023)**
  - Low Fuel Prices
  - Gas Competes with Coal
  - Federal Incentives for Renewables Sunset as planned
  - Low Load Growth
  - Utilities Continue Slow Decarbonizing
- **Medium/Long Term (2024 and Beyond)**
  - \$20/ton Carbon Tax by 2026
  - Coal units become intermediate resources
  - Renewables added when economics dictate (boosted by \$20 carbon tax however)

Green/De-carbonizing

- **Near Term (2018-2023)**
  - Higher Natural Gas Prices
  - Lower economic growth translates into lower load growth
  - Federal Incentives for Renewables Sunset as planned
- **Medium/Long Term (2024 and Beyond)**
  - \$40/ton Carbon Tax by 2026
  - Federal RPS of 20% by 2030
  - Renewables are economically viable without incentives

10.3 BASE CASE STORYLINE/TIMELINE

The IMPA Base Case (Base Case hereafter), reflects IMPA's most unbiased estimate of what the electric utility industry will look like over the coming 20 to 25 years. The overriding assumption is that current forward markets for power, natural gas, and to a lesser extent, coal, are unbiased estimators of future spot prices. As such, the expectation is that wholesale power markets will continue to be beset by oversupply issues and low spot market prices in the near term, particularly as utilities and market participants operate in policy vacuum with the current administration's review of the CPP.

Near Term Characteristics – (2018-2023)

- Relatively low natural gas prices
- Relatively low coal prices
- Natural gas continues to compete with coal for baseload generation
- Federal Incentives for renewable generation sunset as planned
- Load growth generally below the level of national economic growth
- Utilities continue to decarbonize portfolios

Intermediate Term Characteristics – (2024 through 2029)

- Nominal natural gas prices remain below long term average
- Coal pricing remains soft, staying below natural gas on MMBtu basis, nominally.
- Despite coal being more competitive as fuel, we anticipate a bilateral compromise on how best to handle carbon emissions. $20/ton CO_2 carbon "tax" by 2026.
- Portfolio shift to baseloading of combined cycles in MISO and PJM

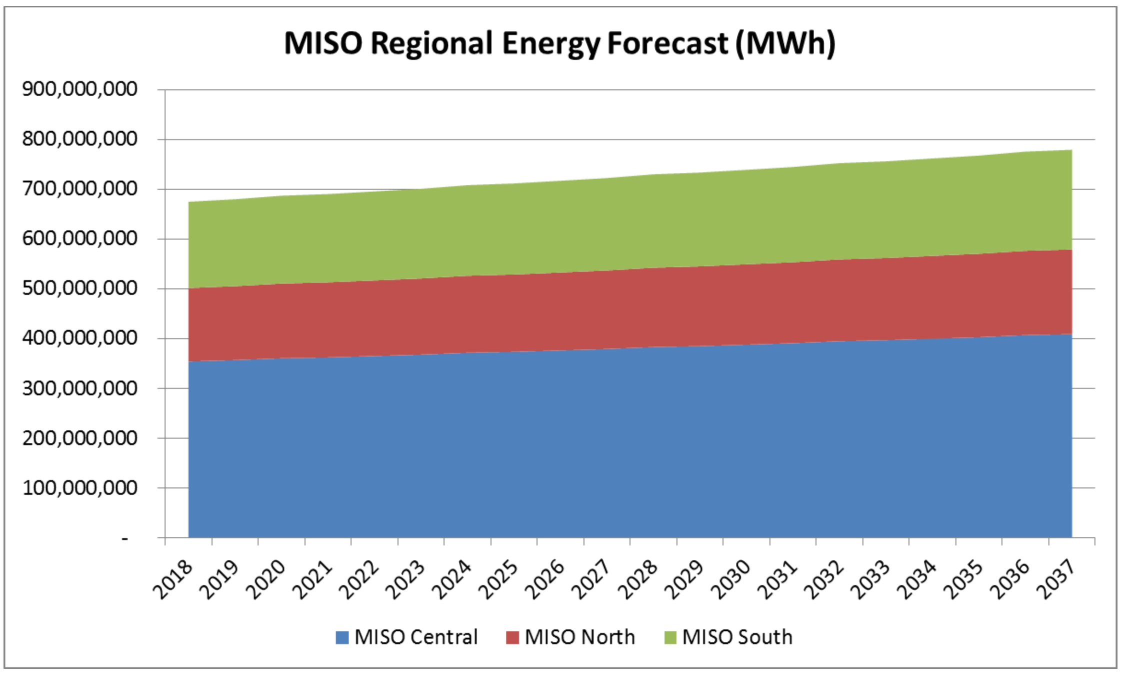
Long Term Characteristics – (2029 and beyond)

- Natural gas prices exceed long term average prices while coal prices continue to remain below natural gas prices
- Combined Cycles dominate the "bottom of the stack" while coal becomes intermediate to peaking supply in certain regions or is retired outright.

ISO/RTO Load Growth

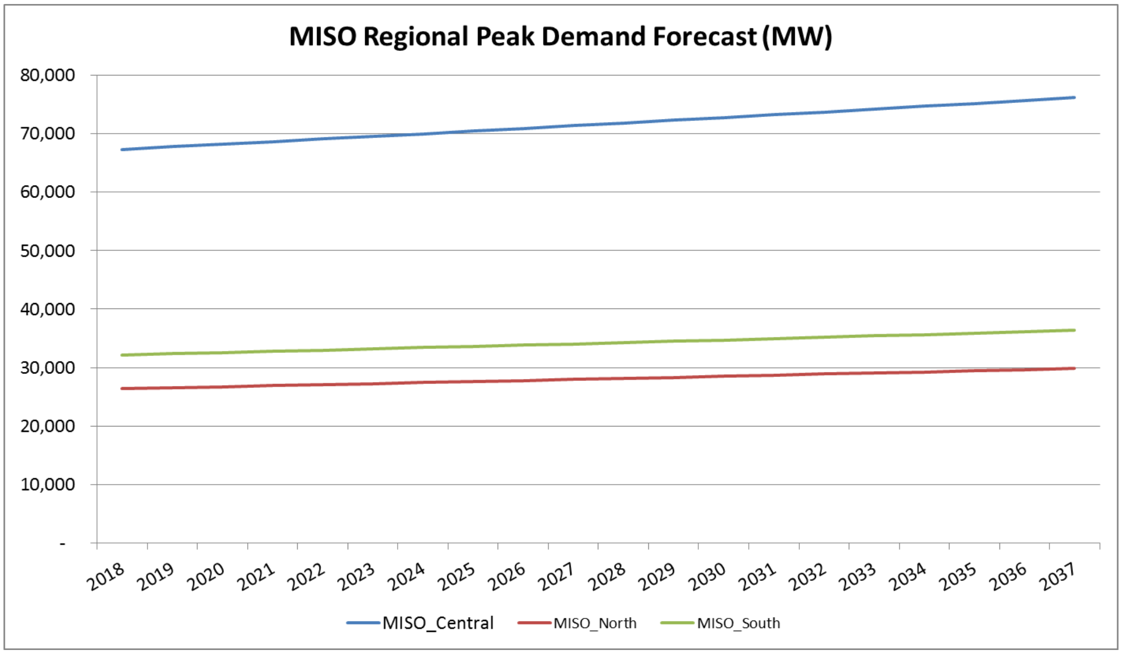
A key assumption in forecasting and planning, particularly as it pertains to future capacity expansion, is determining growth rates for energy consumption and demand. IMPA models the entire Eastern Interconnect in its expansion planning and as such, must supply internal models with load forecasts for PJM, MISO, SERC, NYISO, ISO-NE, and SPP. Of these, the two largest areas with the most interconnectedness are PJM and MISO, which also happen to be the two markets where IMPA serves load. As a result, those two ISOs will be the focus of discussion. For IMPA specific load forecasts please refer to section 5.0 in reference to the Base Case load forecast.
IMPA relies on each ISO/RTO to supply to its stakeholders a long term forecast for energy and demand growth. These forecasts are then fed into IMPA's long term expansion model and serve as a key input to that model. IMPA selected the long term forecast from MISO's Transmission Expansion Plan for 2016 (MTEP16). This forecast extends to 2030 and projects MISO's energy growth at a .76% CAGR and demand at a .65% CAGR. [6] IMPA selected the MISO MTEP forecast for its conservatism and use of member supplied forecasts for MISO's Module E Capacity Tracking Module. The figures below illustrate the forecasted rates for MISO's energy and demand by modeled region.

Figure 17 MISO Base Case Regional Energy Forecast



[6] https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP16/MTEP16%20E2%20EGEAS_Assumptions.pdf

Figure 18 MISO Base Case Regional Demand Forecast



For the PJM forecast IMPA used the January 2017 PJM Load Forecast Report.[7] This load forecast is prepared by the PJM Resource Adequacy Planning Department and contains long term forecasts for loads and energy for each of the transmission zones located in PJM. In general the PJM macro forecast is relatively muted due to low expectations for household formation. PJM is forecasting RTO wide energy demand growth of around .3% over the next 20 years. Peak demand growth is expected to grow at a .2% CAGR over the same period. The tables below illustrate the energy and demand forecast for PJM by major region.

[7] http://www.pjm.com/~/media/library/reports-notices/load-forecast/2017-load-forecast-report.ashx

Figure 19 PJM Base Case Regional Energy Forecast

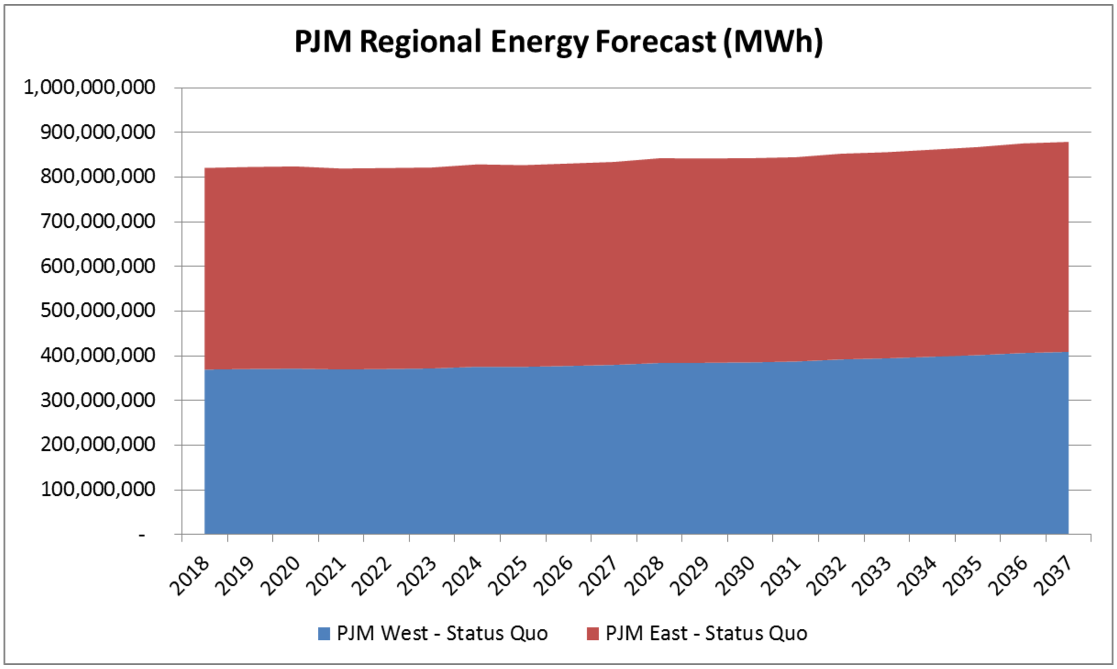
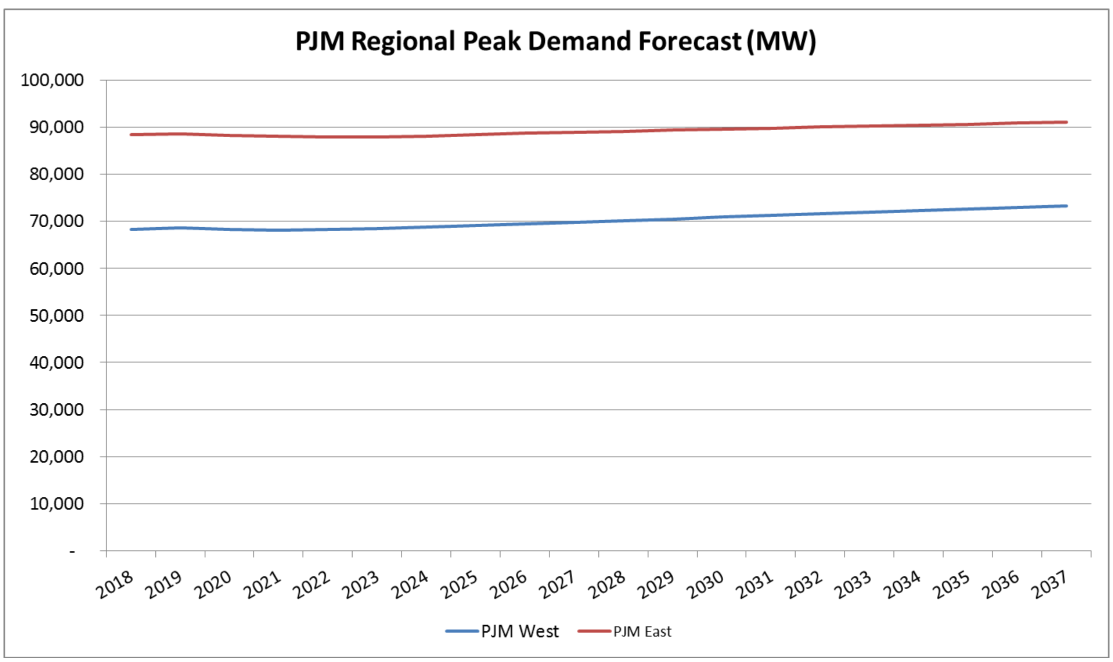


Figure 20 PJM Base Case Regional Demand Forecast



Overall, these rates are considerably lower than projected growth rates for the US economy as a whole. The table below illustrates a sample of real GDP growth forecasts by a variety of unbiased organizations.

Table 14 Real GDP Growth Forecasts

GDP Survey Data						
Year/Provider	OECD	CBO	IMF	EIU	World Bank	UN
2017	2.27%	2.32%	2.30%	2.30%	2.20%	2.00%
2018	3.0%	2.01%	2.50%	2.10%	2.10%	2.00%
2019	2.64%	1.71%		1.00%	1.90%	
2020	2.57%	1.54%		2.00%		
2021	2.51%	1.77%		2.00%		
2022	2.48%	1.89%				
2023	2.45%	1.91%				
2024	2.42%	1.92%				
2025	2.40%	1.90%				
2026	2.38%	1.89%				
2027	2.37%	1.88%				
2028	2.36%					
2029	2.33%					
2030	2.28%					
2031	2.23%					
2032	2.18%					
2033	2.14%					
2034	2.09%					
2035	2.04%					
2036	1.99%					
2037	1.95%					

Federal Incentives for the Deployment of Renewable Energy

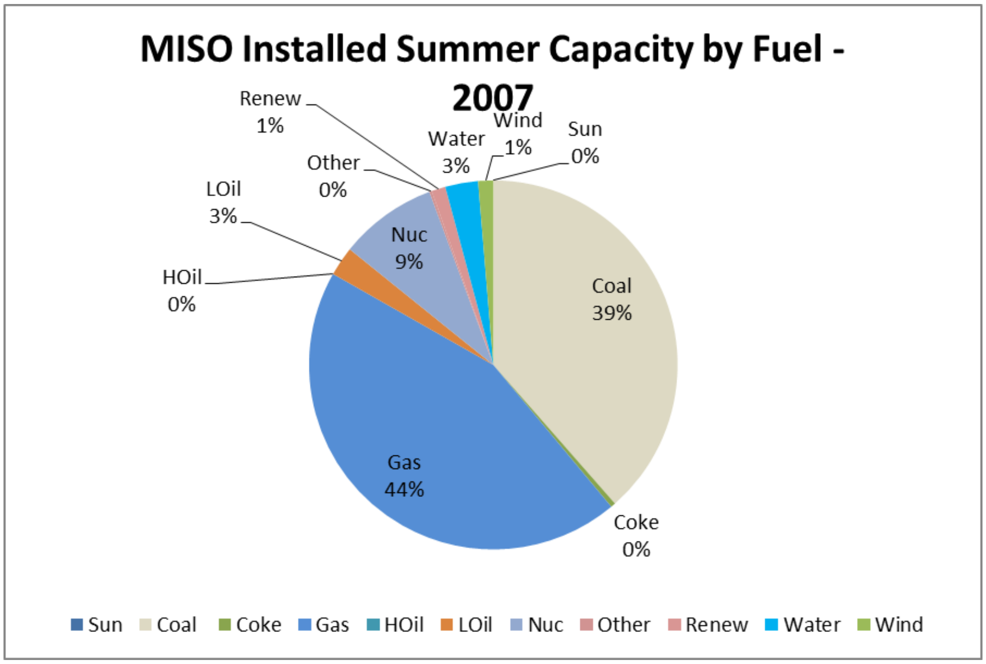
A key driver of supply of new electric generation will be the deployment of renewable resources. IMPA's Base Case assumes that the Federal Renewable Production Tax Credit (PTC) and Investment Tax Credit (ITC) are allowed to sunset and expire as currently covered in "The Consolidated Appropriations Act of 2016".[8] This sets the PTC for wind projects commencing construction prior to December 31st, 2016 at $23/MWh. For projects commencing construction after 2016, there is a 2000 basis point per year reduction in the PTC. The PTC has duration of ten years after a facility is placed in service. The ITC, which is principally used in solar deployments, is 30% through 2019. There is a 400 basis point drop in subsequent years until dropping to a permanent 10% credit in the year 2022 for commercial projects.

De-carbonization of Generation Portfolios

IMPA's Base Case shows that generation portfolios continue to decarbonize in the face of the continued retirement of older, less competitive coal fired generation and the relatively attractive capital costs offered by less carbon intensive forms of generation such as natural gas and renewables. MISO's supply stack has become increasingly wind heavy in terms of installed summer capacity. The figure below illustrates the evolution of MISO's supply stack from 2007 (pre Entergy Integration) and to today's configuration.

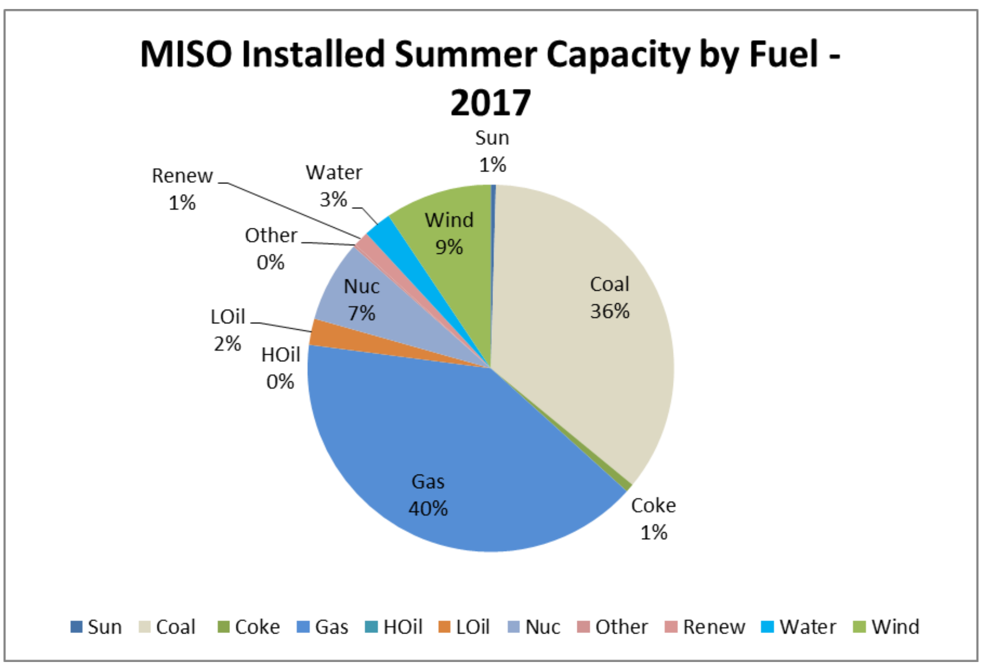
[8] https://energy.gov/savings/renewable-electricity-production-tax-credit-ptc

Figure 21 2007 MISO Installed Capacity



Based on summer capacity ratings, 82% of MISO's supply stack was sourced from either coal or natural gas fired generation, with wind, solar, hydro, and other renewable energy supplying 4%. In ten years, MISO's supply stack shifted to the configuration shown below.

Figure 22 2017 MISO Installed Capacity



Coal and natural gas generation were displaced slightly while renewables increased from 4% to 14% of installed capacity with the largest increase in installed capacity coming from wind.

10.3.1 Base Case Near Term Characteristics (2018-2023)

Over the near term of the next 4 to 5 years, IMPA expects wholesale power markets to be characterized by conditions of oversupply as demand continues to stagnate, natural gas prices remain low, and matters of energy policy are largely pushed to the back burner while larger geopolitical issues take center stage. Towards the end of the Obama administration the PTC and ITC were extended, but with an added sunset provision. This coincided with the phase-in of the Clean Power Plan, which would have had a compliance deadline that coincided with the phase-out of the PTC and ITC[9]. This could be characterized as phasing out the "carrots" and phasing in the "sticks" as it pertains to a national energy policy. Thus far, the Trump administration seems inclined to let the PTC and ITC die their natural deaths. However, with a Supreme Court stay on the CPP and subsequent administrative efforts to repeal the CPP, the "stick" phase is more unclear. On March 28th, 2017, President Trump signed the Executive Order on Energy Independence which seeks to review a number of Obama era policies enacted toward the end of that administration. [10] With energy policy stalled, market participants will look to price signals in forward markets to drive decision making. In other words, what are forward markets for wholesale power, natural gas and coal suggesting about future developments in wholesale energy markets, in addition to optimizing their long term power supply portfolios?

Future expectations for fuels are a key driver of forward prices for wholesale energy prices. In addition, the relationship between forward fuel prices can send market participants signals about expected marginal resources in the supply stack for a given period.

IMPA relies on coal forecasts from two main sources. The first is a coal forecast from JD Energy, Inc. This forecast covers the primary physical markets in the United States (e.g., Illinois Basin) and is supplied bi-annually. The forecast period covers current year through 2045. IMPA blends the relevant JD Energy forecast with swap futures quotes from S&P Global Market Intelligence[11] to arrive at an estimate for forward prices. These forward prices can then be used to gauge potential future profitability for coal fired assets by comparing a coal generators future expected variable cost against the market for wholesale power prices. This margin is colloquially known as the "dark spread." The figure below illustrates the dynamic between what is expected to be a coal generators variable cost against the forward market for wholesale power prices at Indiana Hub for the On-peak and Off-peak periods and the associated spread. Variable cost in this instance is assumed to be the forward market for coal against a 10.059 MMBtu/MWh heat rate and $5.00/MWh in Variable O&M.

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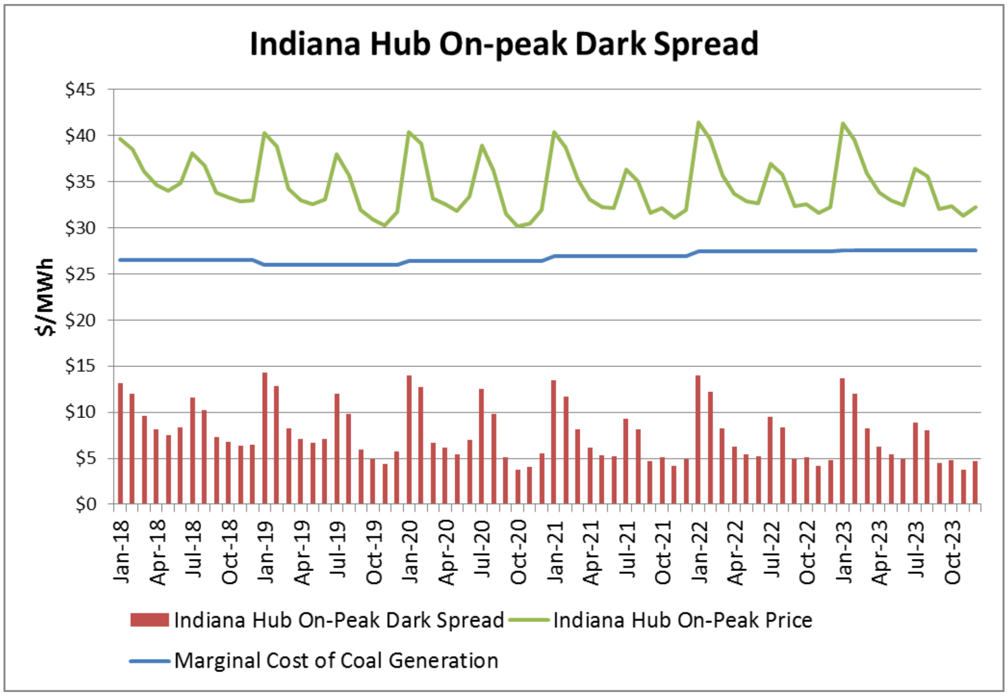
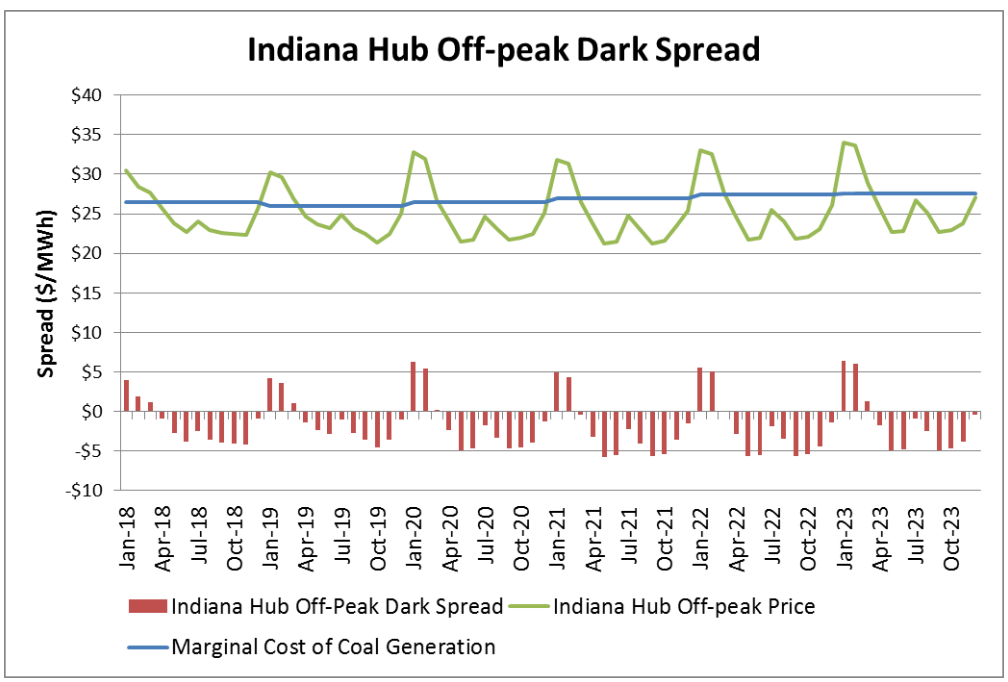
[9] https://www.c2es.org/docUploads/cpp-implementation-timeline-20160222.pdf
[10] https://www.epa.gov/energy-independence
[11] S&P Global Market Intelligence; SNL Energy Data

Figure 23 Indiana Hub On-peak Dark Spread



As illustrated in the figure above, in the short term, coal fired assets are expected to maintain summer and winter profitability during the On-peak hours, however, that profitability is expected to decline over the near term of 4 to 5 years. An examination of the Off-peak dark spread shows a more challenging environment as the only real periods of firm profitability are during the winter months. The figure below illustrates this dynamic.

Figure 24 Indiana Hub Off-peak Dark Spread



In addition, it should be noted that while these are useful proxies for determining expected asset profitability, they oversimplify the picture somewhat as they do not account for increased costs associated with cycling coal units to chase profitable hours, nor do they account for the potential costs stemming from transmission congestion at the generator source. Ultimately the conclusion drawn is that over the near term, coal fired assets are likely to face a challenging operational environment.

In contrast to forward coal prices, natural gas markets are generally larger and more liquid. As a result, IMPA uses natural gas futures quotes from S&P Global Market Intelligence. Of most significance are quotes for natural gas priced at Henry Hub, which is the reference price for most natural gas transactions. Expected profitability from natural gas units can be determined in a manner similar to measuring a coal unit's dark spread. For natural gas fired units this spread is known as the "spark spread." Selection of the appropriate heat rate varies depending on the type of natural gas fired generator being examined. Peaking natural gas units may have heat rates between 10 and 12 MMBtu/MWh while combined cycle technologies may possess heat rates ranging from 7 to 8 depending on configuration and lower for newer units. For a benchmark, the EIA uses 7.65 MMBtu/MWh for a natural gas fired combined cycle.[12] The figure below illustrates the spark spread for a new 6.5 MMBtu/MWh heat rate combined cycle against the Indiana Hub On-peak power price factoring in just fuel and variable O&M of $3.5/MWh. This represents the expected marginal cost of a new combined cycle entering the market place.

[12] https://www.eia.gov/electricity/annual/html/epa_08_02.html

Figure 25 Indiana Hub On-peak Spark Spread

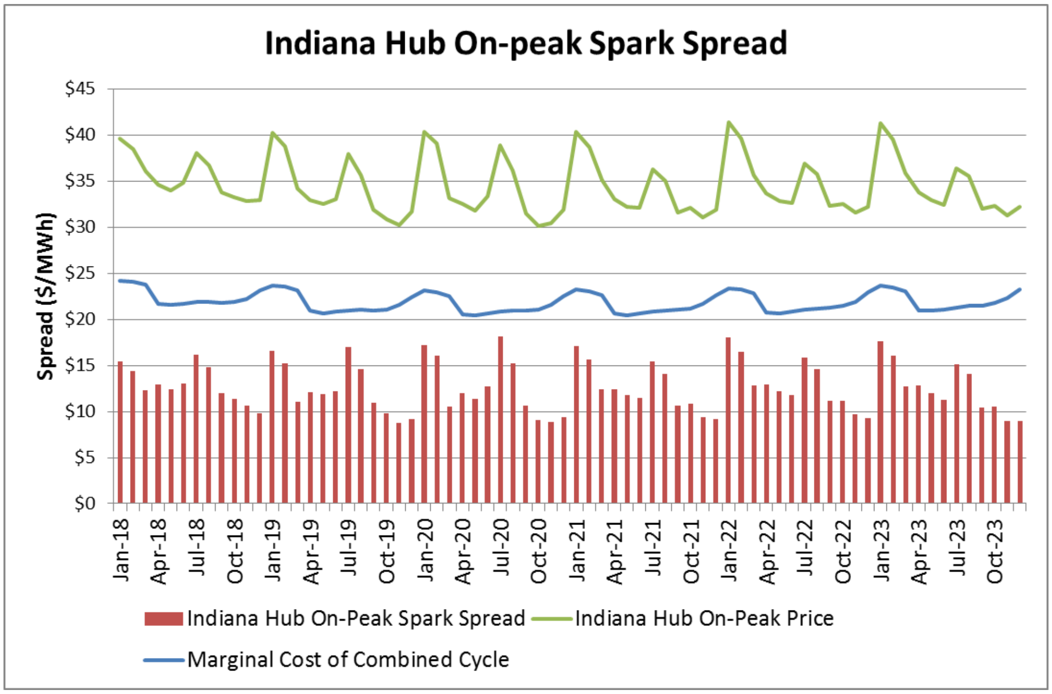
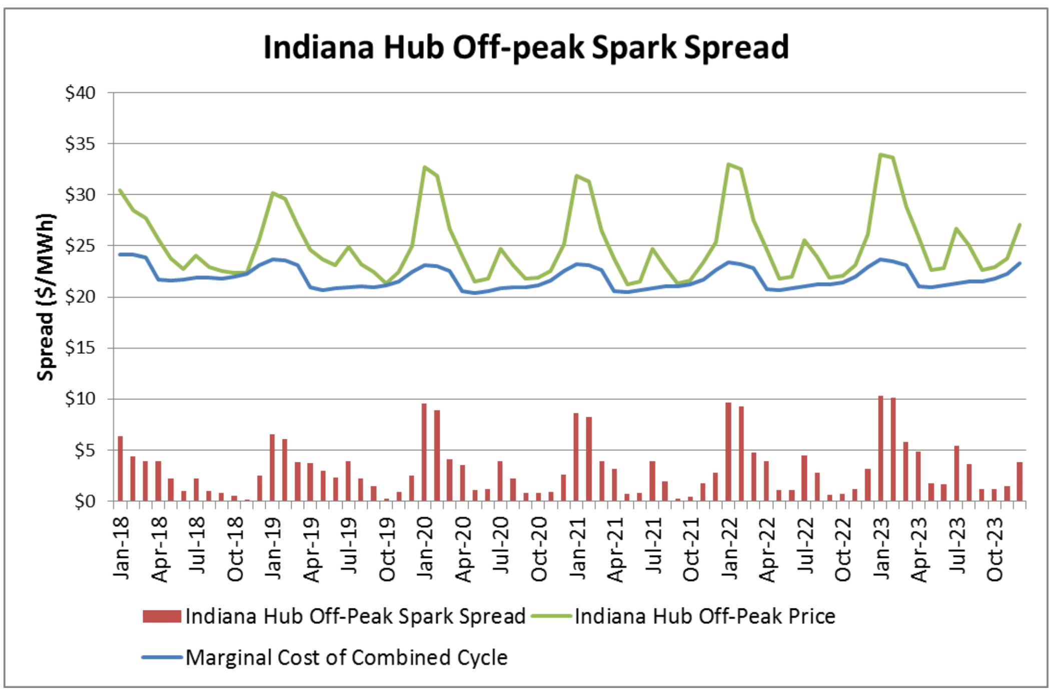


Figure 26 Indiana Hub Off-peak Spark Spread



As the figures above show, a new combined cycle is "in the money" not only during the On-peak hours but also during the Off-peak hours. This is in contrast to coal, which is frequently out of the money during Off-peak hours.

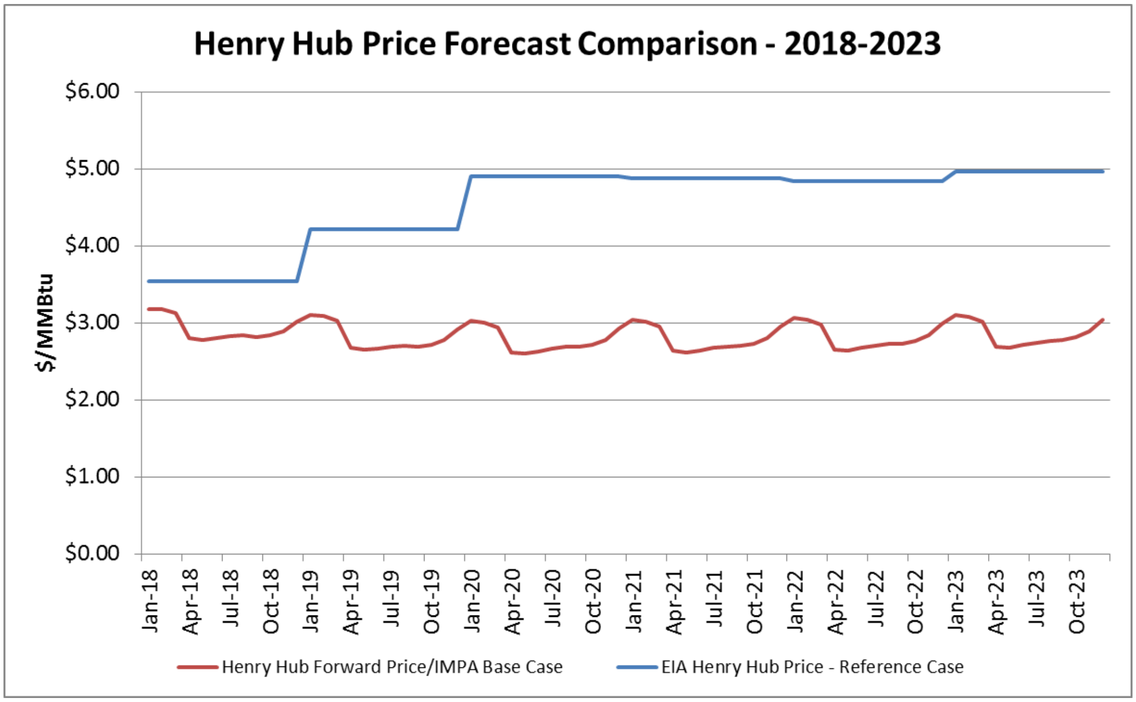
In addition, combined cycle units have generally better operational flexibility than coal units, which enhances their ability to respond to price signals.

Fuel Prices

While the section above briefly touched on short term fuel prices and their relation to generating asset profitability, this section outlines just near term fuel price expectations for the Base Case.

The figure below illustrates the current forward curve compared to the EIA Henry Hub Price in the EIA reference case. For the purposes of the IRP, IMPA's Base Case is the forward curve for Henry Hub Natural Gas futures.

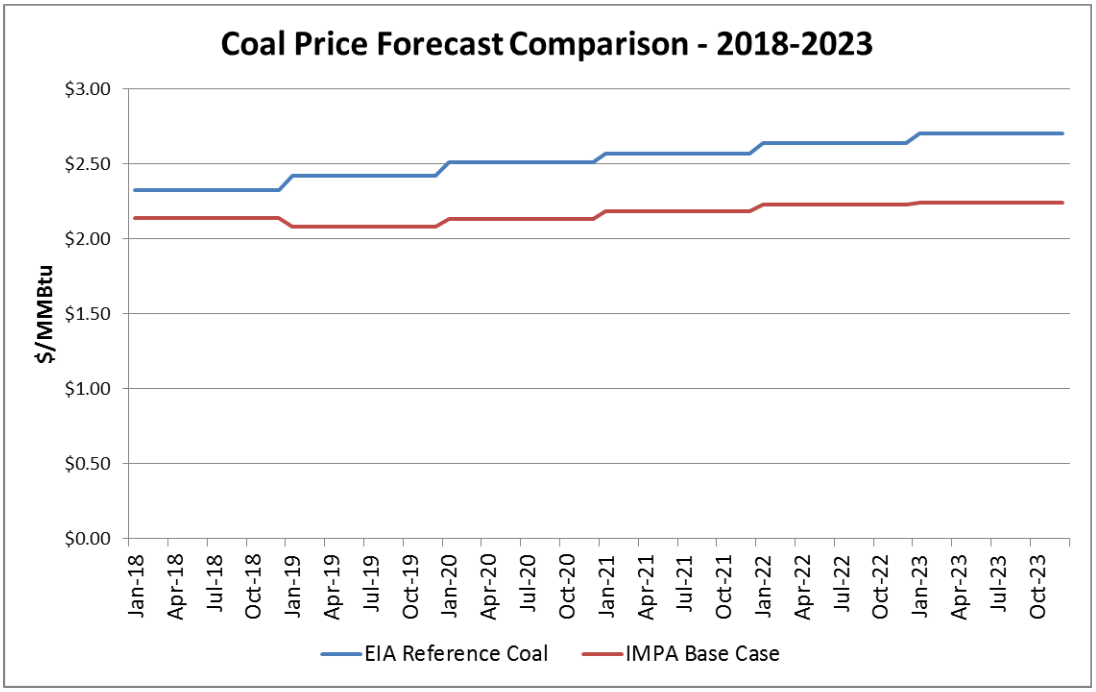
Figure 27 Base Case Natural Gas Price Forecasts (Near Term)



As illustrated the forward curve for natural gas is considerably lower than the EIA reference case. IMPA assumes that any information about the probability of policy legislation regarding carbon should be captured and fully discounted in the forward curve above as the market for natural gas is liquid and transparent.

The following figure illustrates the forward curve for coal prices. For near term price forecasts, IMPA relies on a composite forecast for coal from JD Energy in addition to forward coal prices.

Figure 28 Base Case Coal Price Forecasts (Near Term)



10.3.2 Intermediate Term Characteristics (2024-2029)

Over the intermediate term, IMPA assumes that natural gas prices will exceed coal prices, nominally, on an MMBtu basis as reflected by forward prices. Despite coal's competitiveness as a fuel, IMPA assumes the biggest development will be on the policy front. In 2026 IMPA assumes bi-lateral compromise will be reached on carbon policy and this will manifest itself in the form of a $20/ton carbon tax in 2026. Ultimately, this cost will be primarily borne by generators and as such, impacts to fuel prices are expected to be minimal. As a confirmation, IMPA utilized the EIAs 2017 Annual Energy Outlook to compare their reference case, which assumes the adoption of carbon caps via the Clean Power Plan, and their reference case with no Clean Power Plan implementation. Between the two cases, there is a $.01/MMBtu difference in forecast Henry Hub prices on a nominal basis in 2025. By 2040, the difference widens slightly, to $.07/MMBtu.[13]

Carbon Policy

Moving into the intermediate term of the long term scenario, forecasting becomes more problematic as market pricing for power, natural gas, and capacity products becomes less visible and the information contained in those prices more difficult to ascertain. IMPA assumes a key development will be the adoption of some sort of carbon reduction policy. This can either take the form of some sort of emissions cap, a cap and trade regime, or a tax. Of these, IMPA feels the most likely form this takes is a simple carbon tax. While the subject is divisive among policy makers, the tone of the industry seems to be converging on carbon pricing as a means to both address climate change and as a way to provide price support for generators who are potentially

[13] https://www.eia.gov/outlooks/aeo/pdf/appe.pdf

handicapped by a low price environment despite being carbon neutral sources of baseload generation (e.g., nuclear).[14]

Determining what price to use in its forecast, IMPA looked to other states that currently require quantifying carbon costs as part of their planning process as well as other proposed carbon pricing regimes. This summer, Minnesota regulators increased the state's social cost of carbon from a range that was previously $.44/ton to $4.53/ton to a new range of $9.05-$43.06/ton by 2020.[15] Meanwhile, Colorado regulators ordered Xcel Energy to utilize the federal social cost of carbon construct despite a freeze in federal guidance on matter. This ruling forces Xcel to use a social cost of carbon that starts at $43/ton in 2022, escalating to $69/ton by 2050.[16]

These states are historically aligned with progressive policies on environmental matters and may represent relatively high boundaries for a possible cost to carbon pricing. The Climate Leadership Council, a more politically conservative group with founding members that also include a number of petroleum refiners, advocates for a carbon tax that would be remitted to all Americans in the form of a dividend. Their proposal suggests "…a sensible carbon tax might begin at $40/ton and increase steadily over time…"[17] With what seems like both sides of the political spectrum proposing values that would start around $40/ton that may suggest a reasonable starting point. However, assuming some opposition to a carbon tax of any kind would arise, it stands to reason these numbers would be negotiated lower in whatever the final form would take. IMPA, therefore, has settled on a carbon tax of $20/ton starting in 2026. This value represents a midpoint between those who would no doubt argue vehemently against any carbon tax and $40/ton. In terms of phase in dates, IMPA felt 2026 would represent a reasonable start date given that the current administration has been actively taking steps to roll back or pause previously proposed/enacted environmental policies (e.g., Clean Power Plan). 2026 would represent 2 years into a new administration in a potentially "open" 2024 election.

Fuel Prices

As noted above, IMPA does not anticipate that the adoption of a carbon tax will have a material impact on fuel prices that is not otherwise already factored into observable forward markets. These forward price assumptions are reflected in the figure below.

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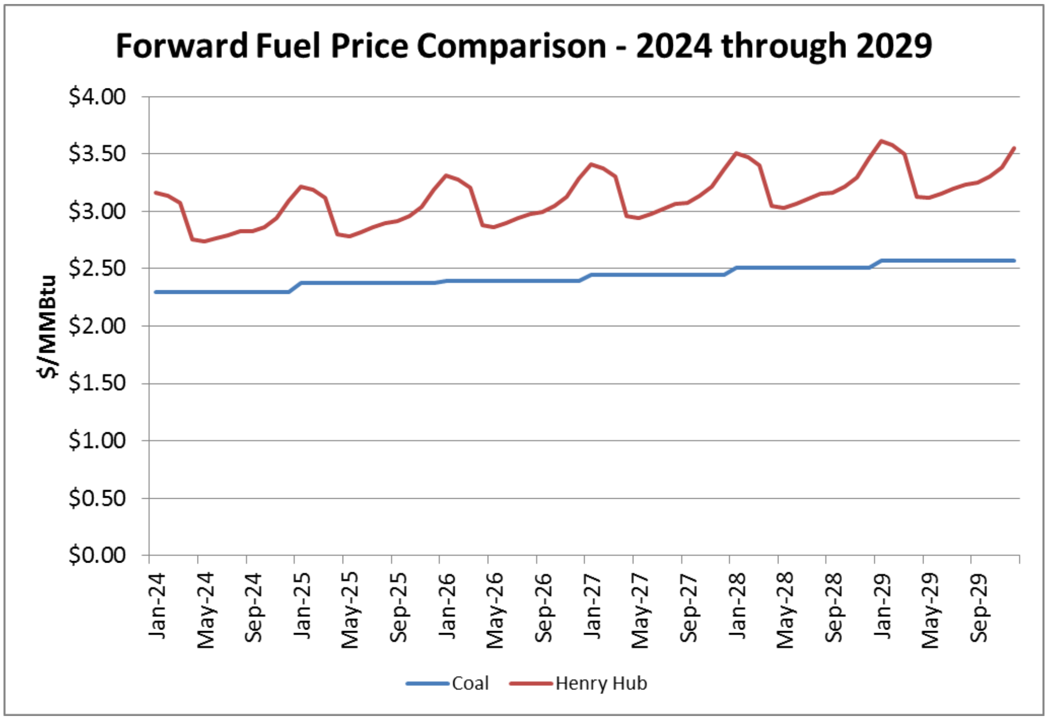
[14] http://www.utilitydive.com/news/the-carbon-consensus-generators-analysts-back-co2-price-at-ferc-technical/441862/

[15] http://www.startribune.com/minnesota-regulators-increase-social-cost-of-co2-emissions-but-not-as-much-as-asked/437066353/

[16] http://www.utilitydive.com/news/colorado-regulators-seize-the-climate-fight-in-landmark-ruling-on-carbon-co/443186/

[17] https://www.clcouncil.org/our-plan/

Figure 29 Base Case Forward Fuel Prices (Intermediate Term)

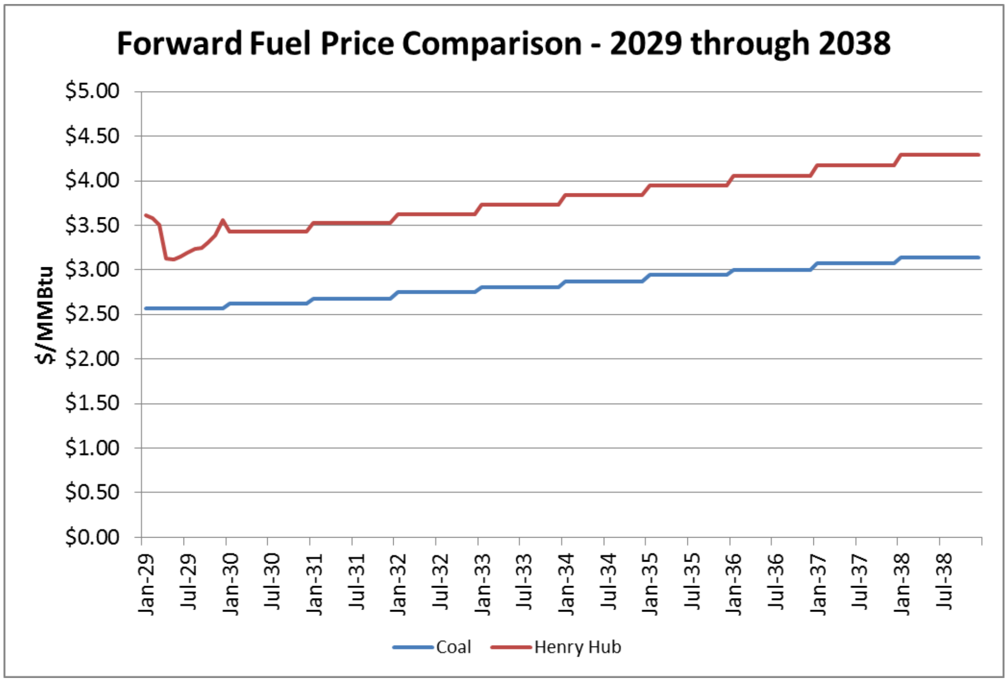


Nominal prices for both natural gas priced at Henry Hub and coal are expected to see modest year over year increases during this time period. Coal prices continue to be a blend of JD Energy forecasts and bilateral transactions where available. The generally upward sloping curve for natural gas is consistent, particularly compared to a relatively flat forward curve for coal, with the narrative that demand for coal will remain in equilibrium with supply as natural gas becomes a preferential fuel in carbon tax regime. As environmental costs mount for coal, relative to natural gas, the expectation is that coal units will be pushed “up the stack” in MISO while natural gas and some renewables become new baseload resources.

10.3.3 Long Term Characteristics (2029 and beyond)

With forward markets for coal and natural gas becoming increasingly illiquid or not quoted past 2029 (earlier for coal), future prices for fuels are increased at a rate that is consistent with the year over year increase in more liquid points on the curve and extended to the end of the forecast period. Pricing for natural gas is essentially an annual average price, but then shaped to determine monthly prices. In these outer years, natural gas prices are expected to revert to long term averages of around $4.00/MMBtu while coal prices are expected to remain below natural gas prices. Nevertheless, with carbon pricing still in effect, natural gas is expected to be the fuel of choice in supplying system generation and new capacity builds.

Figure 30 Base Case Forward Fuel Prices (Long Term)



10.4 Green Case Storyline/Timeline

The IMPA Green Case reflects a worldview that signatories of the Paris Agreement will ultimately make a best efforts attempt to structure policies consistent with the agreement's goal of holding the increase in global average temperatures to below 2 degrees Celsius. In IMPAs view, this is likely to take the form of a Federal Renewable Portfolio Standard (RPS) and a $40/ton tax on carbon dioxide emissions. Consequently, economic growth is expected to be lower, trending on the lower end of consensus estimates due to higher input costs to manufacturing processes. In addition, natural gas prices are expected to be higher than currently reflected in the Base Case as a tighter regulatory regime (i.e., increased fracking regulation), leads to constrained supply despite increased demand from natural gas fired generators.

Near Term Characteristics (2018-23)

- Gradually escalating natural gas prices after 2020.
- Unchanged coal prices from Base Case
- Natural gas continues to compete with coal for baseload generation
- Federal incentives sunset as planned for renewable generation
- Lower than Base Case load growth (1.5% real GDP growth)

Intermediate Term Characteristics – (2024-29)

- Accelerated increase in natural gas prices
- Phase in of Federal RPS of 20% by 2030
- $40/ton tax on CO_2 emissions
- Accelerated retirement of coal fired assets
- Increased utilization of natural gas fired assets
- Increased buildout of renewable generation

Long Term Characteristics – (2029 and beyond)

- Natural gas prices converge to EIA base case price

ISO/RTO Load Growth

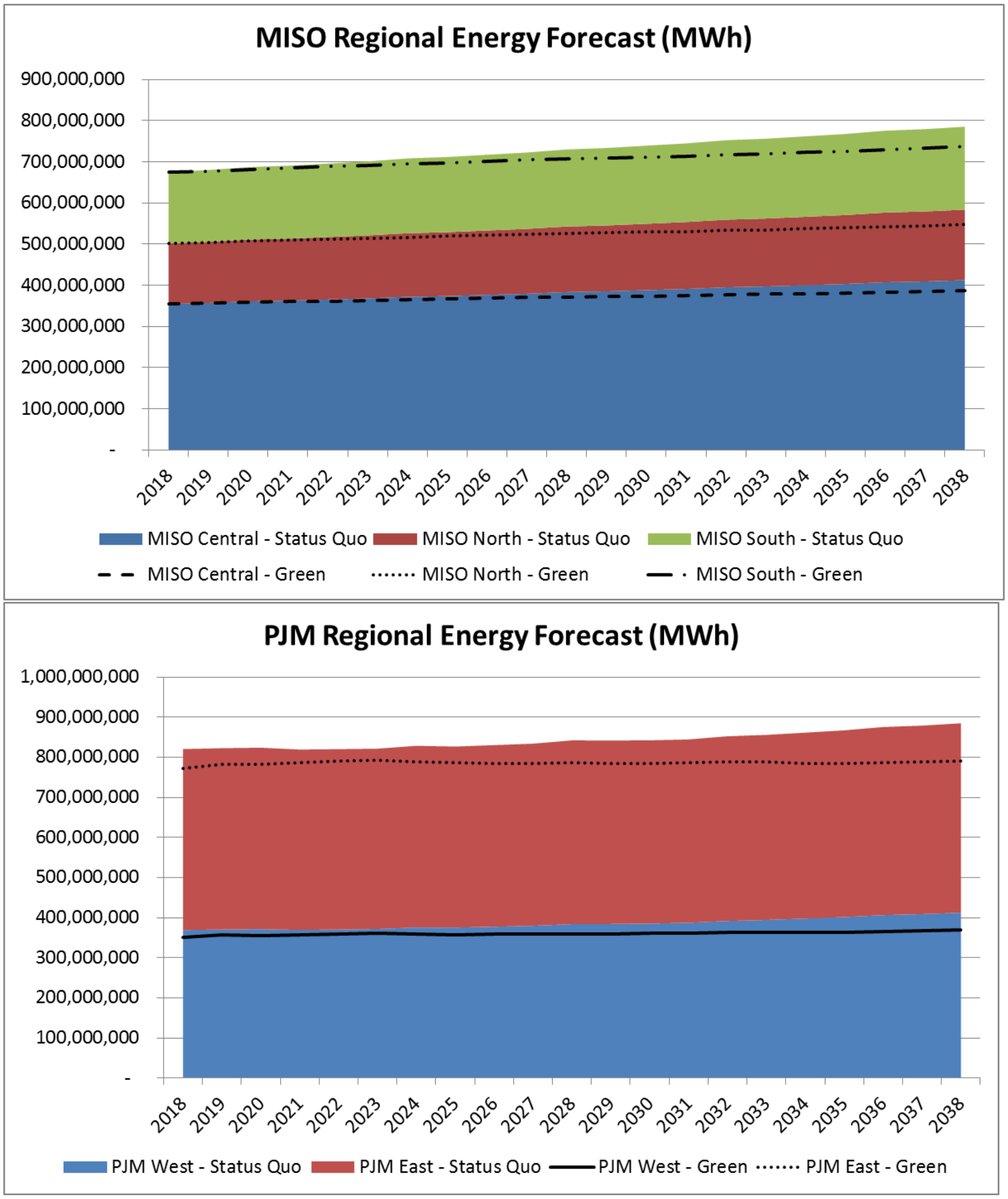
When approaching how best to forecast load growth in the Green Case, IMPA first referred to the OECD's Green Growth Strategies document in order to familiarize itself with how policy makers might enact sustainable and environmentally friendly policies in the future.[18] At the core of their framework is instituting policies that make for a more efficient use of resources and emphasize minimal environmental impacts. Succinctly stated, the OECD contends that innovation must play a role in order to move past what would just be capable of being accomplished using current technology and altering consumer behavior. IMPA agrees with this statement and, absent technological innovation, the primary policy tool to bridge the gap between technological regimes is changing consumer behavior. This implies a reduction of consumption either by more stringent efficiency standards or by increasing the cost of products to account for social costs. As discussed, IMPA assumes the most likely policies to be enacted in this environment are a carbon tax of $40/ton and a Federal RPS mandate. In addition, it is likely that efficiency standards on home heating and cooling will increase. These policies in the short and intermediate terms are likely to dampen economic growth and will certainly lower load growth for utilities. In order to forecast ISO/RTO load growth for the Green Case, IMPA first lowered the economic growth rate

[18] http://www.keepeek.com/Digital-Asset-Management/oecd/environment/towards-green-growth_9789264111318-en#.WbwkF2BK1UY#page11

assumptions for its own load forecast as a sensitivity to the Base Case forecast. The subsequent year over year impact to the IMPA load forecast was applied to the Base Case forecasts for the ISO and RTO forecasts.

The figures below overlay the new loads over the Base Case forecasts. As illustrated in the figure below, energy use is expected to increase at a slower rate in the Green Case versus the Base Case.

Figure 31 MISO and PJM Green Case Load Forecast Comparison



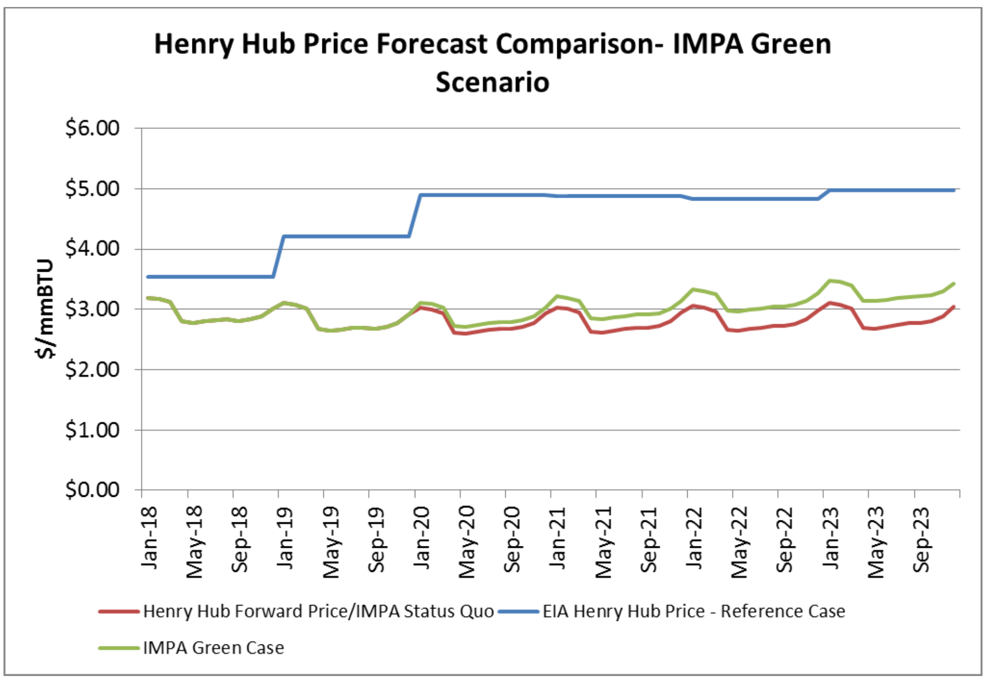
10.4.1 Near Term Characteristics (2018-2023)

Over the very near term, IMPA's Green Case closely resembles the Base Case owing to the fact that any shift to a "green" policy mandate will have to wait until at least the next presidential election in 2020. IMPA expects any policy shift towards a "green" bias will first materialize in natural gas prices, likely prior to 2020 as markets begin discounting a potential change in administration. This increase would be due to market expectations of tighter environmental regulations on natural gas drilling, leading to tighter natural gas supply in the face of potentially higher demand as utilities shift portfolios away from coal and towards cleaner natural gas. Despite the shift towards greener policies, IMPA assumes the era of incentives for renewable technology are over and instead a mechanism of forced compliance will be adopted, most likely in the form of a Federal RPS. Because of this change in emphasis, IMPA assumes the ITC and PTC for wind and solar are allowed to sunset, as is assumed in the Base Case. As a result of forced environmental compliance, manufacturing input costs are expected to increase, ultimately lowering real GDP growth to below consensus rates. Consequently, IMPA expects that load growth will be slower than under the Base Case.

Fuel Prices

As a starting point, IMPA referenced EIAs Annual Energy Outlook, 2017 for a baseline, "Green" case estimate for fuel prices as EIA's reference case includes the implementation of the Clean Power Plan, which serves as a useful proxy for environmental policy impacts on fuel pricing. The challenge with using the EIA's reference case however is the presumption of a near instantaneous shift in policy. The figure below illustrates the forward curve for natural gas at Henry Hub in the EIA's reference case and the current, forward curve for natural gas at Henry Hub. Note the latter is also the IMPA Base Case fuel price assumption.

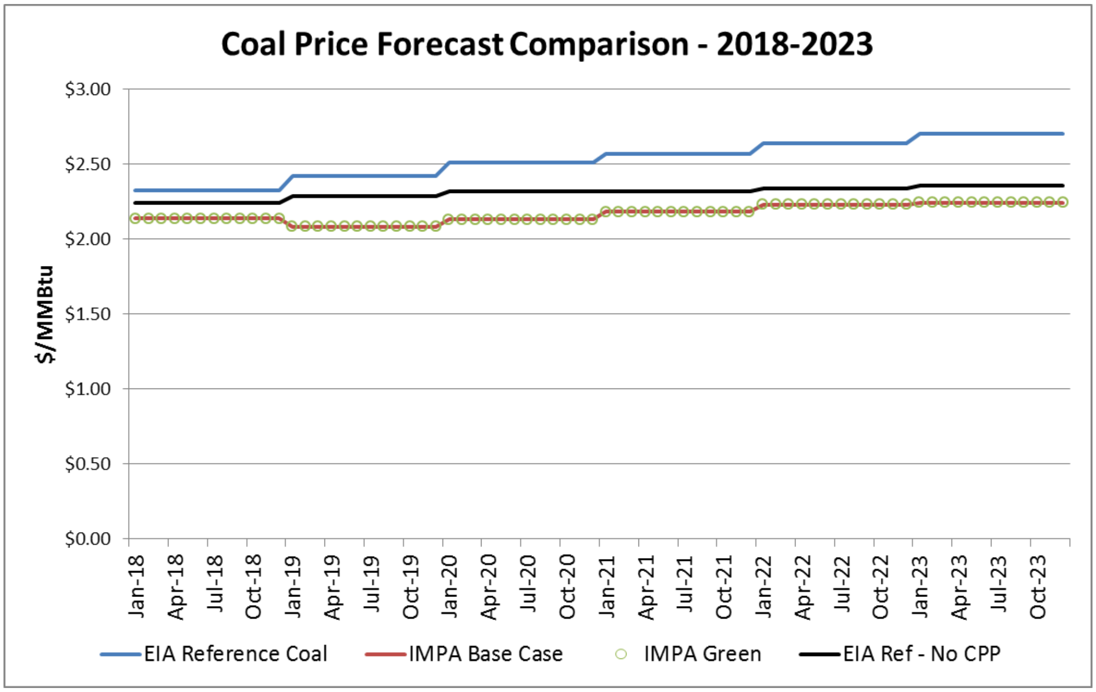
Figure 32 Natural Gas Price Forecast Comparison (Near Term)



Over the near term, IMPA assumes any shift in the policy regime would not start being discounted by markets until early 2020. As a result, IMPA blends the current forward curve with the EIA reference case forecast to arrive at an expected future spot price for natural gas at Henry Hub. Market observed prices get a heavier weight in earlier years before gradually transitioning to the EIA reference prices.

The differences in coal prices however are less pronounced between the EIA reference case and the current forward curve as the figure below shows.

Figure 33 Coal Price Forecast Comparison (Near Term)



IMPA's view is that given the ample recoverable coal reserves in the United States[19], supply should generally be able to keep pace with demand, particularly in slowly dwindling demand environment. In other words, the supply and demand outlook for coal should be fairly stable regardless of a "'green" policy backdrop and absent any draconian legislation against coal. As such, IMPA assumes that the Base Case reflects a certain degree of de-carbonizing already and in the near term the "Green Case" coal price is expected to be the same or similar to the Base Case.

10.4.2 Intermediate Term Characteristics (2024-2029)

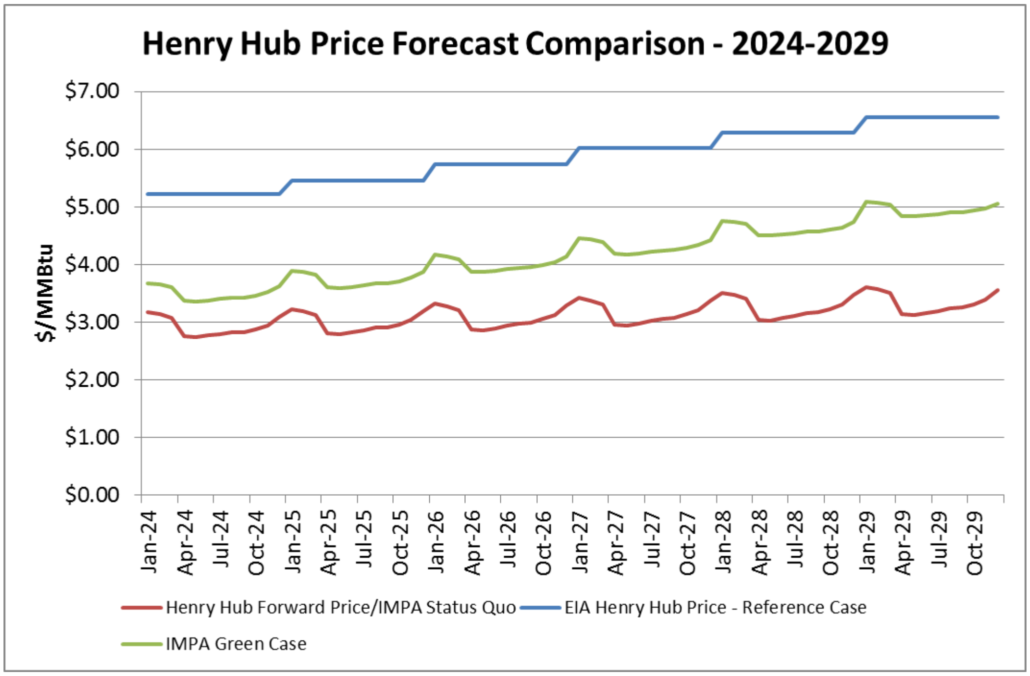
In the intermediate term IMPA anticipates a Green Case to evolve to one of wider disparity in fuel prices as policies enacted to contain global warming begin to gain traction and impacts from implementation begin to materialize. On the policy front, utilities will be increasing renewable generation sources in their power supply portfolios in response to a Federal RPS of 20% energy sales by 2030. In addition, the Green Case is assumed to have a more aggressive carbon tax than the Base Case, starting at $40/ton in 2026. These factors are expected to combine to drive an accelerated increase in coal fired asset retirements, an increased reliance on natural gas, and a proliferation of renewable sources of generation in power supply portfolios.

[19] https://www.eia.gov/coal/reserves/

Fuel Prices

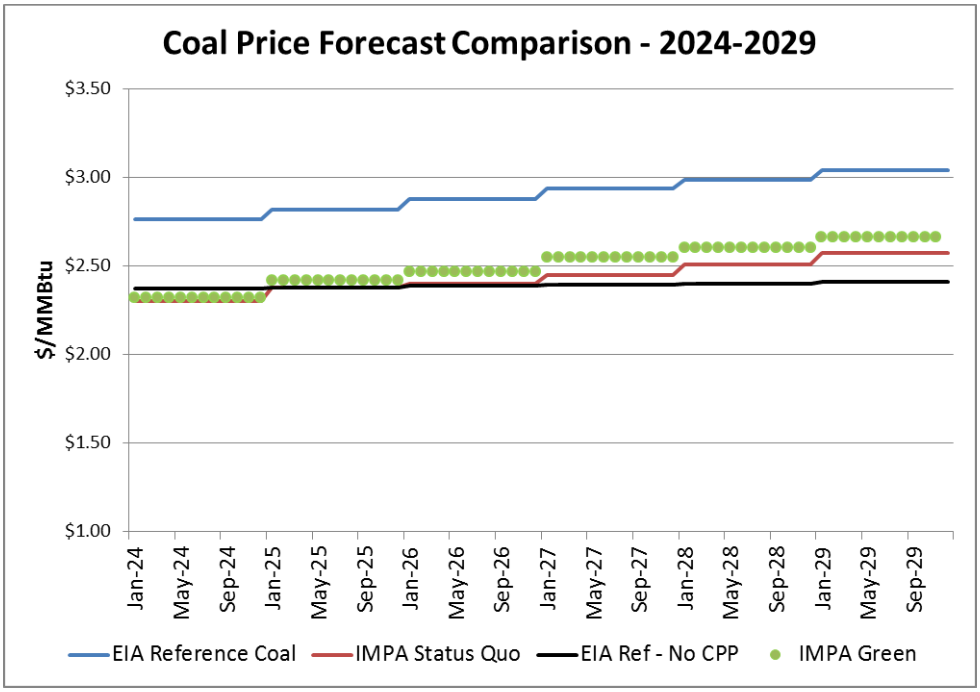
As noted above, in the Green Case, policy outcomes are largely expected to drive fuel prices, which in turn will drive portfolio decisions and wholesale power prices. The figure below illustrates Henry Hub natural gas prices across the intermediate term for the EIA reference case, the Base Case and the Green Case.

Figure 34 Henry Hub Price Forecast Comparison (Intermediate Term)



The figure below illustrates Henry Hub natural gas prices across the intermediate term for the EIA reference case, the IMPA Base Case and the IMPA Green Case. Over this time frame, the Green Case diverges more materially from the IMPA Base Case, while remaining less aggressive than the EIA reference case. As for coal, IMPA anticipates that the Green Case will see reduced mine capacity and a somewhat tighter supply environment, resulting in slightly higher prices over this period.

Figure 35 Coal Price Forecast Comparison



Despite this tighter supply environment, coal will not be in a position to have much, if any pricing power given the availability of substitute options available to utilities, such as retiring coal fired assets and switching to gas and renewable generation sources.

10.4.3 Long Term Characteristics (2029 and beyond)

Beyond 2029, the landscape for the Green Case is one of increased renewable generation penetration as 2030 is the final year for compliance with the 20% Federal RPS.

Figure 36 Natural Gas Price Forecast Comparison (Long Term)

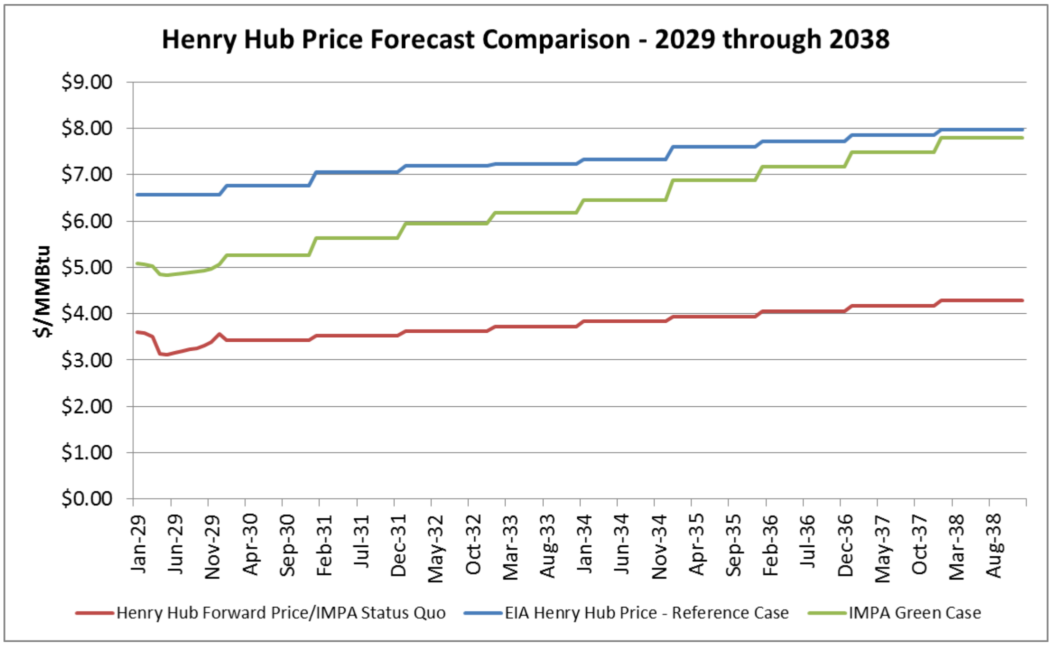
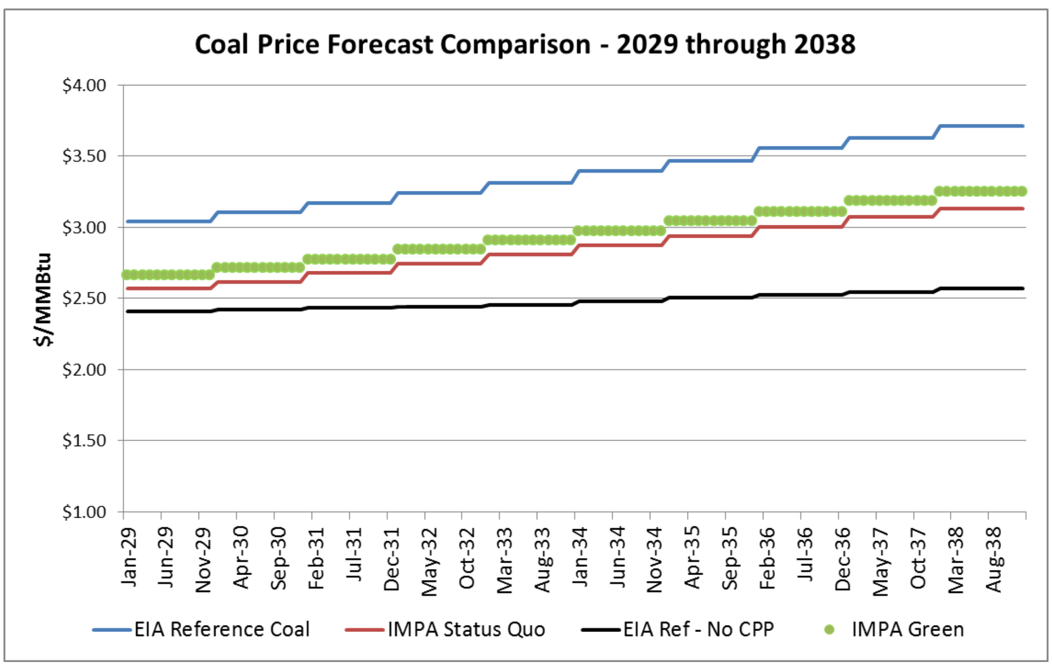


Figure 37 Coal Price Forecast Comparison (Long Term)



10.5 HIGH GROWTH/DEREGULATION STORYLINE/TIMELINE

The IMPA High Growth/Deregulation Case (High Growth Case, hereafter), reflects IMPA's best vision as to what a low regulation, high economic growth world would entail in terms of energy demand and fuel prices. From a policy standpoint, this case could be called the supply siders' dream, whereby the dominate policy regime is one that supports totally free markets and opposes barriers that would otherwise impinge on the supply of goods and services to the market. With that in mind, the High Growth Case assumes lax environmental regulation, particularly as it pertains to drilling and mining activities. In addition, existing rules for the ITC and PTC are expected to sunset in the High Growth Case as is seen in the Base and Green Cases. Growth rates of 2.6% real GDP growth are borrowed from the EIA's Annual Energy Outlook 2017.
The following bullet points summarize the characteristics of the High Growth Case.

Near Term Characteristics (2018-2023)

- Strong long term economic growth (2.6% real GDP growth)
- Higher than Base Case fuel prices as economic growth sparks a slight demand shock
- Higher than Base Case loads and peak demand

Intermediate Term Characteristics – (2024 through 2029)

- Natural gas price increases ease as new supply comes to market
- Coal prices continue to rise, however proven reserves and relaxed mining rules and regulations keep any increases modest
- Existing coal fired generation maintains its position as baseload fuel for most organized energy markets while incremental needs are met with natural gas generation

Long Term Characteristics – (2029 and beyond)

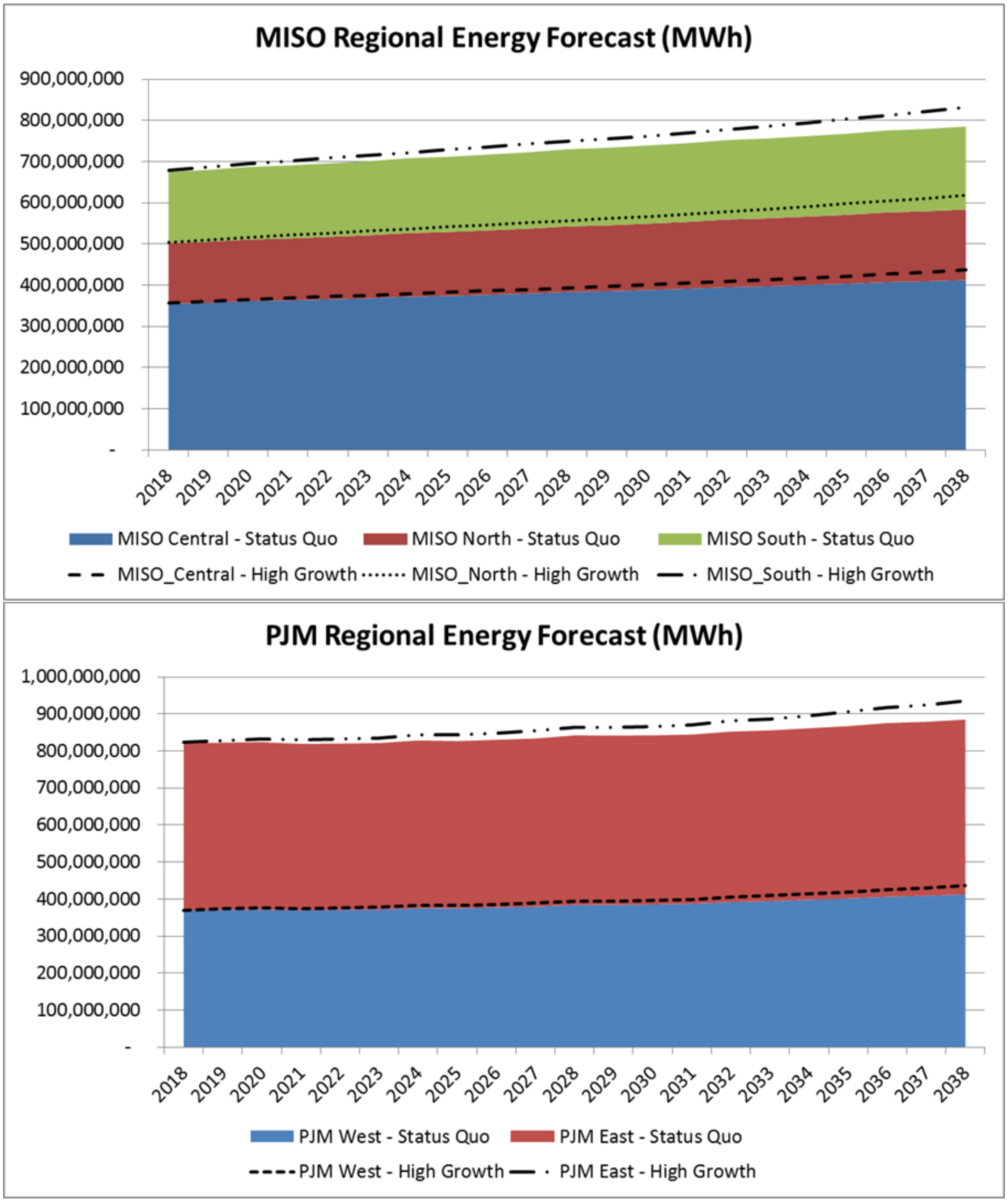
- Natural gas price increases year over year slow versus prior years as supply and demand issues resolve
- Coal prices continue to rise, however at a slower rate than prior years
- In markets where coal has been the traditionally dominant fuel, gas fired assets will be built at a slower rate where existing coal fired generation continues to operate

ISO/RTO Load Growth

For the High Growth Case IMPA has assumed that economic growth exceeds current consensus estimates, growing at a 2.6% real rate for the duration of the study. As noted previously, 2.6% real GDP growth is the assumption used in the EIA's 2017 Annual Energy Outlook for their high growth case. Using the same method that was applied in the Green Case, the new GDP growth rates are applied first to the IMPA load forecast then the resulting growth rate is applied to the ISO/RTO load and peak demand growth rates.

The figures below illustrate the ISO/RTO loads for MISO and PJM under the Base Case with the High Growth Case loads overlaid for comparison.

Figure 38 MISO and PJM High Growth Regional Energy Forecast Comparisons



These figures imply that PJM's load growth is less economically sensitive to changes in economic growth than MISO. However it primarily is reflecting a higher Base Case growth rate for PJM such that additional gains from economic growth are muted.

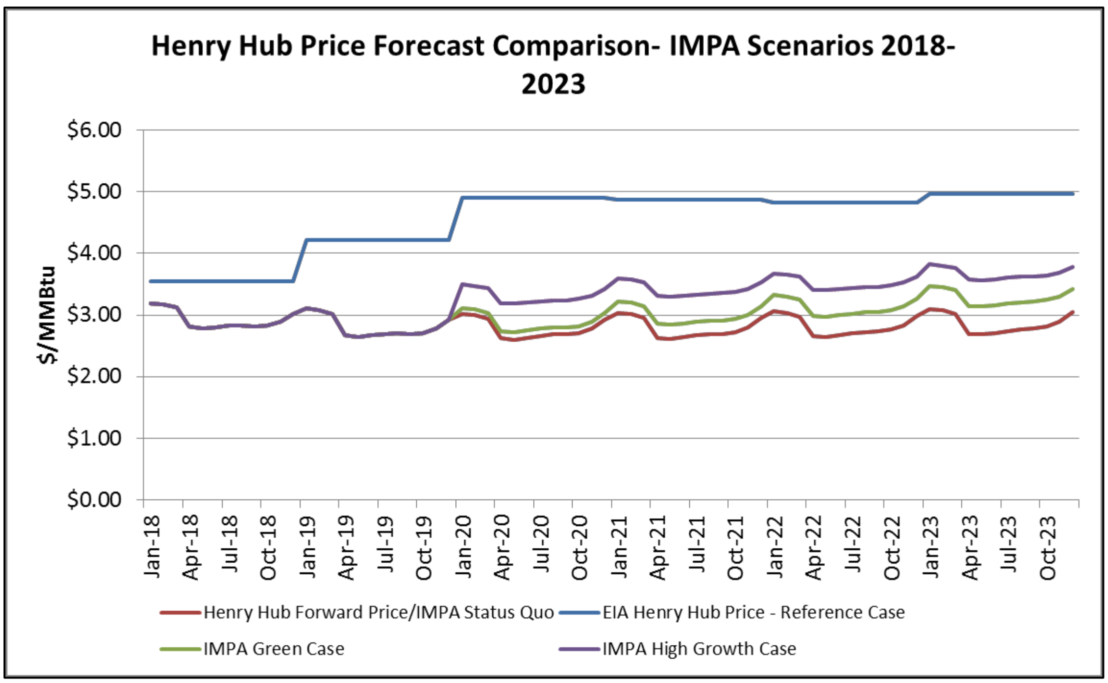
10.5.1 Near Term Characteristics (2018-2023)

Over the near term and lasting the duration of the study's 20 year horizon is the assumption that economic growth persists at a 2.6% real growth rate. This growth rate is consistent with the growth rate used by the EIA in their high economic growth case in their 2017 Annual Energy Outlook and is well above the consensus forecasts for economic growth referenced in the IMPA Base Case. These growth rates are then utilized in IMPA's load forecast models to arrive at new energy and demand forecasts under the new growth rate. This economic expansion is expected to not initially impact natural gas prices significantly until the latter part of the near term window as excess supply is worked through. By 2020 however, natural gas prices are expected to deviate from the Base Case as persistent demand outpaces the growth of new supply. Coal prices are expected to remain relatively muted despite increased demand. As a result, natural gas fired assets are expected to revert back to their more traditional place in the resource stack as intermediate and peaking resources.

Fuel Prices

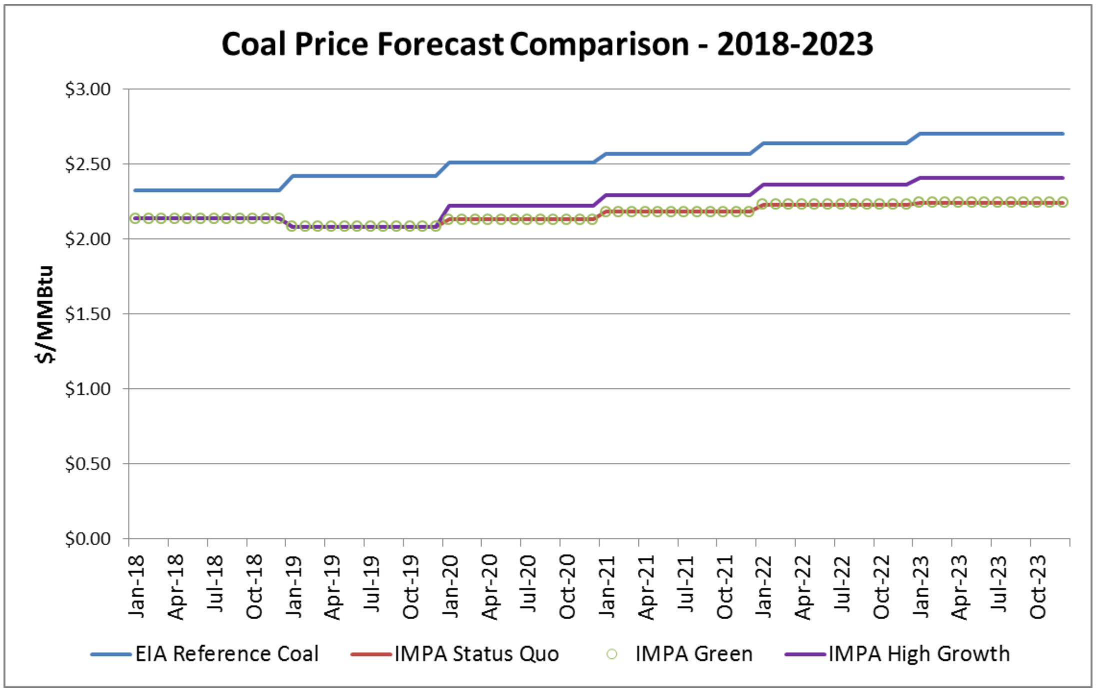
In the immediate near term fuel prices in the High Growth Case are not expected to deviate much from the Base Case despite an immediate assumption of increased economic growth. This view is predicated on current abundance of fuel supplies and the market's ability to absorb some initial demand shocks before materially impacting pricing. The figure below illustrates natural gas prices across all three IMPA scenarios and the EIA Reference Case Henry Hub price for comparison.

Figure 39 Natural Gas Price Forecast Comparison (Near Term)



Coal prices by comparison are more muted than natural gas prices as the High Growth Case assumes fewer regulatory burdens to mining, in addition to a relatively higher level of proven reserves versus natural gas with coal's reserves-to-production (R/P) ratio exceeding natural gas' by nearly 24-1.[20]

Figure 40 Coal Price Forecast Comparisons (Near Term)

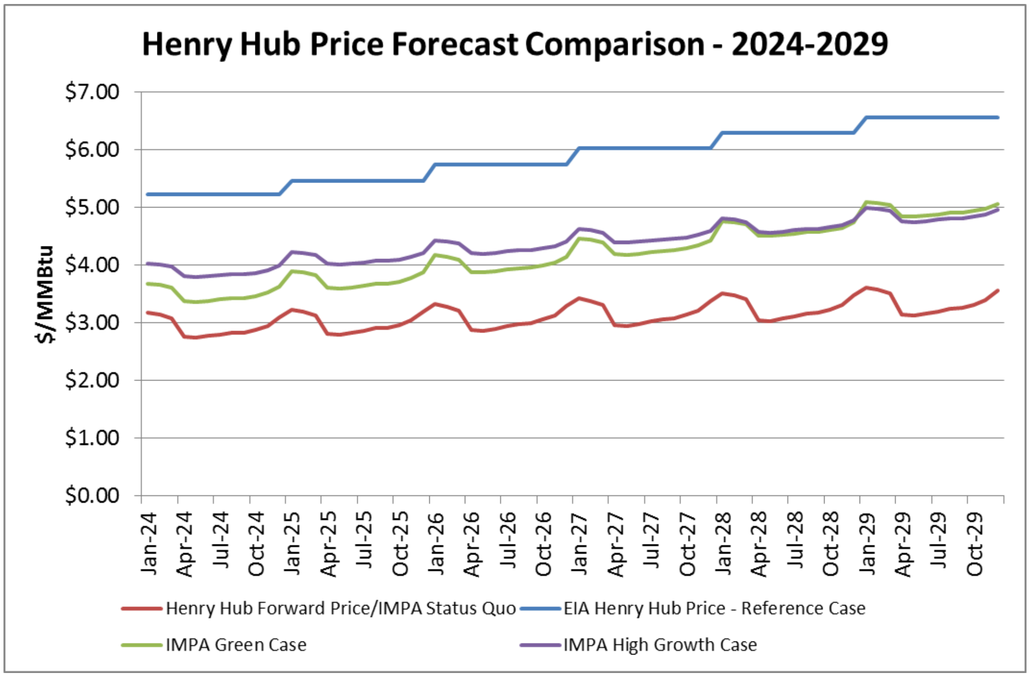


10.5.2 Intermediate Term Characteristics (2024-2029)

In the intermediate term of the High Growth Case, fuel prices are expected to continue their upward trajectory. However, with what is presumed to be a more relaxed regulatory environment, the rate of change in natural gas prices begins to slow, particularly when compared to the Green Case. However, the High Growth Case still sees natural gas prices at levels considerably higher than the Base Case, reaching $5.00/MMBtu by 2029. While this seems high by recent historical standards, it should be noted that this is roughly $1.00/MMBtu below the EIA high growth forecast.

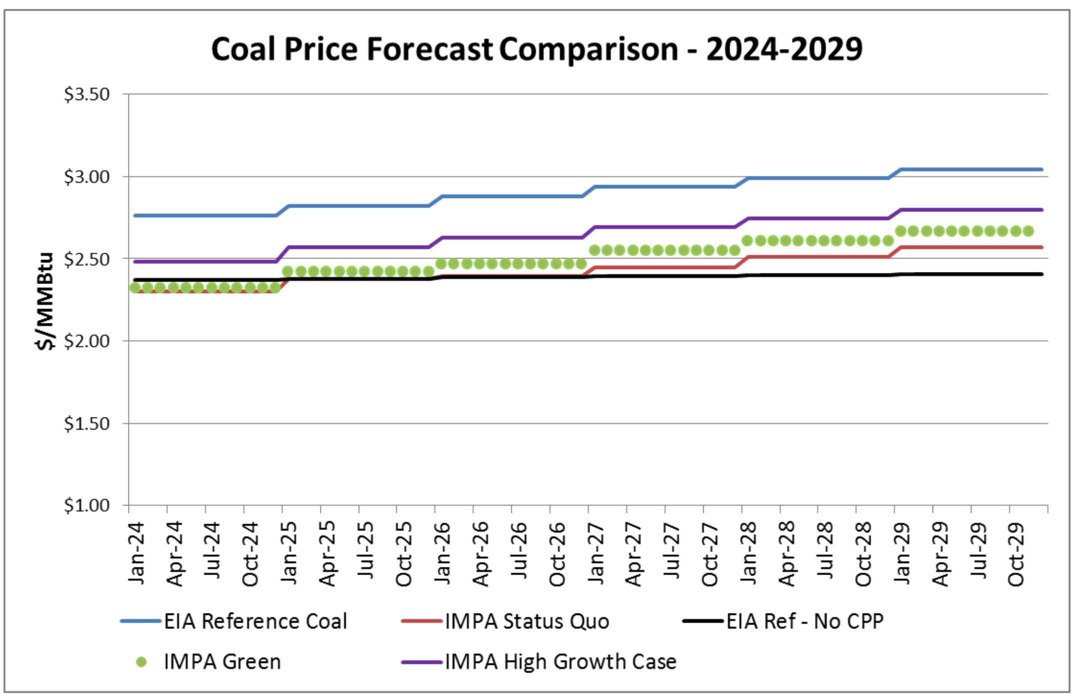
[20] https://www.bp.com/content/dam/bp/en/corporate/pdf/energy-economics/statistical-review-2017/bp-statistical-review-of-world-energy-2017-full-report.pdf

Figure 41 Natural Gas Price Forecast Comparison (Intermediate Term)



Over the intermediate term of the High Growth Case, coal prices are expected to generally trend higher than either the IMPA Green Case or the Base Case as coal is favorably viewed as a source for baseload generation. As mentioned previously, IMPA expects deviations in coal prices to be fairly muted regardless of policy regime due to the ample reserves of coal in the United States.

Figure 42 Coal Price Forecast Comparisons (Intermediate Term)

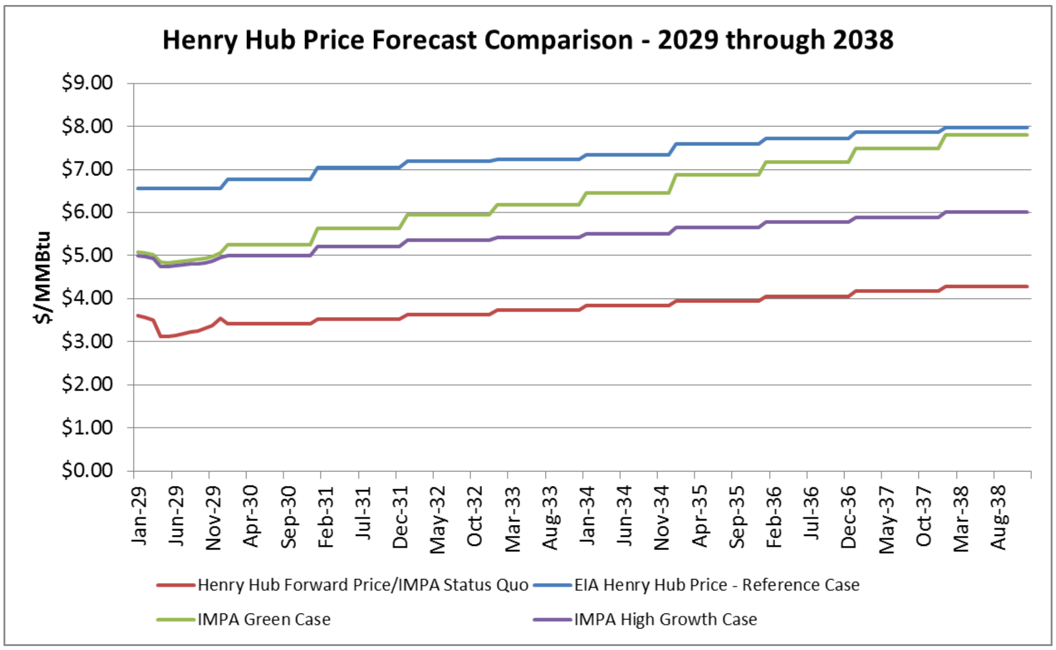


Notably, the IMPA High Growth Case is higher than the EIA Reference Case with no CPP. IMPA's view is that coal suppliers in a high growth/lower regulation regime would enjoy pricing power not seen for some time, hence the higher price versus the EIA Reference Case.

10.5.3 Long Term Characteristics (2029 and beyond)

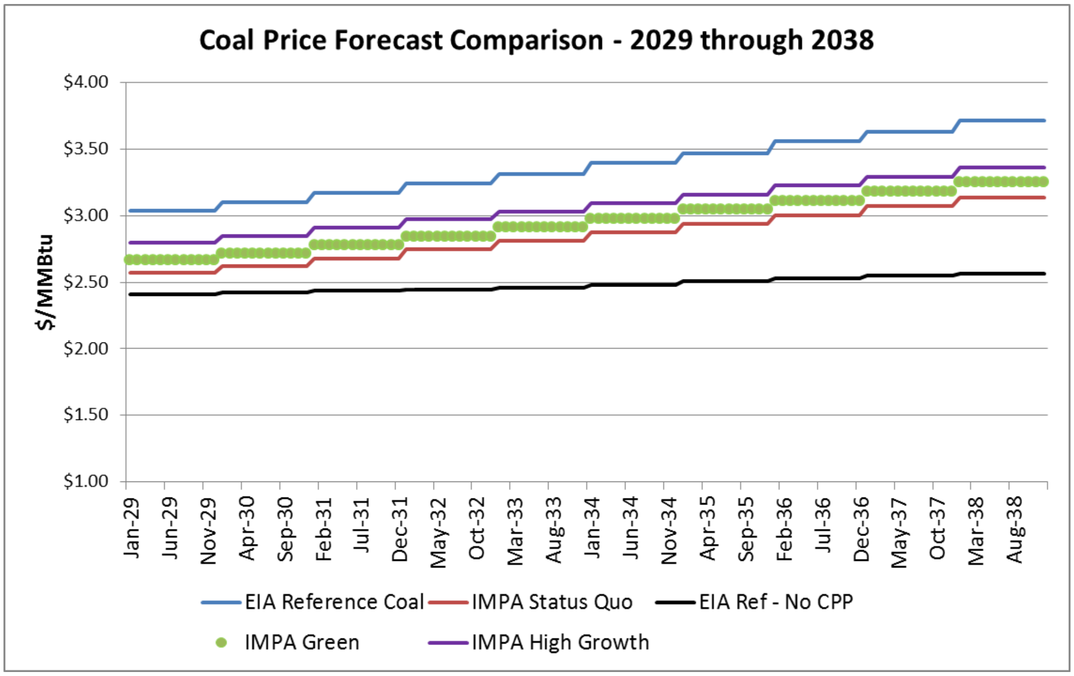
In the out years of the High Growth Case, the landscape is characterized by a spread between coal and gas that is reminiscent of spreads seen prior to the shale gas boom of recent years. For natural gas prices at Henry Hub, the IMPA High Growth Case converges more slowly to the EIA reference case price but faster than the IMPA Base Case.

Figure 43 Natural Gas Price Forecast Comparisons (Long Term)



Nominally the spread between natural gas and coal is expected to widen to around $2.00-$2.50/MMBtu in these out years. This is more consistent with the 10 year average spread. Ultimately this would solidify coal fired generation as a baseload resource in later years while gas fired assets would retain their traditional intermediate and peaking places in the resource stack.

Figure 44 Coal Price Forecast Comparisons (Long Term)



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11 MARKET PRICE FORMATION – AURORAXMP

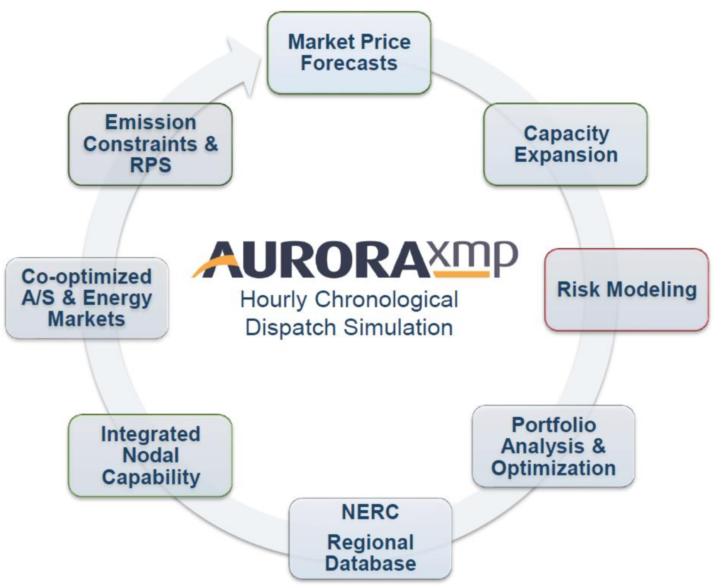
With the implementation of the RTO energy and capacity markets, the future cost of market power and energy is a critical aspect of utility planning. Planning must incorporate a reasonable and realistic forward view of the market. IMPA utilizes market price projections for all planning activities, from short term hedging decisions to long term planning. The AuroraXMP integrated modeling approach creates a fundamental forecast that is internally consistent across supply, demand, fuels, emissions, and transmission. This section of the report discusses IMPA's methodology for creating the market price forecasts used in various aspects of its planning processes.

Once the scenario and drivers have been developed, the next step is to simulate the scenarios by modeling their characteristics into AuroraXMP. For each scenario, the drivers and regulations are simulated to determine a complete regional capacity expansion plan and the corresponding wholesale price for energy and capacity.

AURORAXMP

AuroraXMP performs a chronological market dispatch which considers the market dynamics of power, fuels, transmission, emissions, and renewables.

Figure 45 AuroraXMP



Source: EPIS, Inc.

The model database includes all North American generating assets, hourly loads, transmission interties, fuel supply, etc. The market prices created for capacity and energy are used in the IMPA portfolio portion of the model, which is the same platform.

Market Database

The AuroraXMP database is maintained by EPIS-Aurora and updated at regular intervals.

- Information is provided for over 15,000 generating units
    - Fixed and Variable Operating Costs
    - Heat Rates
    - Emission Rates
    - Forced Outage (FO) and Maintenance Outage (MO) Rates
- Load forecasts by balancing authority
- Zonal transmission capabilities and interchange limits
- Coal price forecast by plant with delivery adders from key basins
- Gas price forecast from Henry Hub with basis and delivery adders
- Other fuel and emissions prices

The Aurora user is able to change any of the inputs desired to reflect updated retirement schedules, new units, unit upgrades, zonal loads, transmission improvements as well as all commodity prices.

When running the simulation in AuroraXMP, the first process of the simulation is to create a long term expansion plan. The model formulates this long term capacity expansion plan at the zonal/regional level. After the long term expansion is optimized, the simulation determines the zonal capacity and market energy prices.

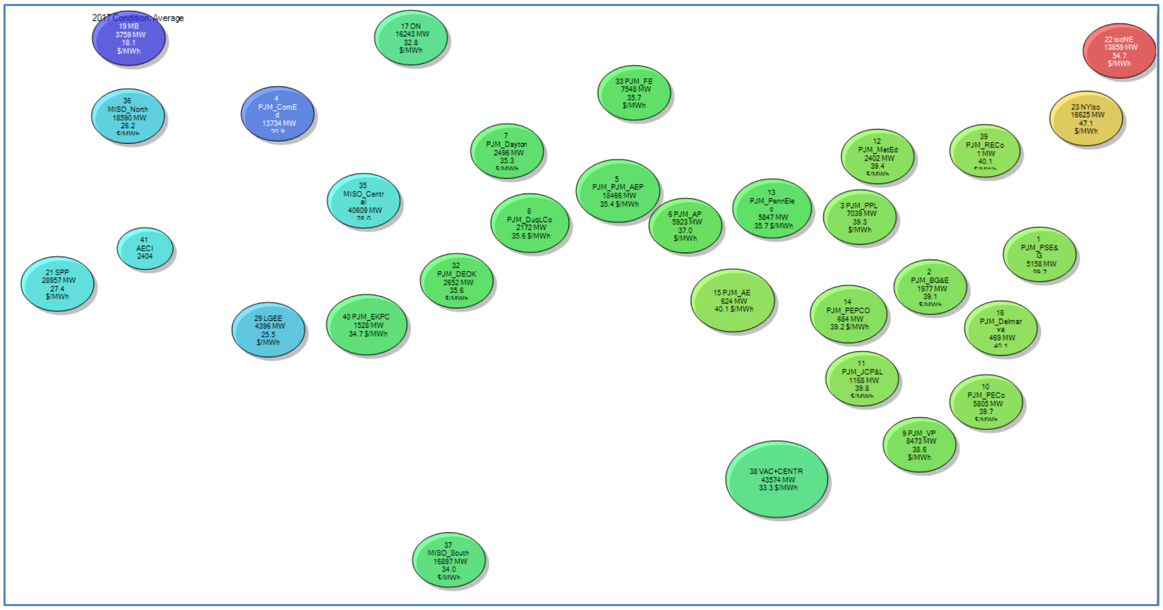
Resource Expansion

The market-based resource expansion algorithm builds resources from a list of candidate resources based on unit profitability and minimum reserve margin requirements as defined by the user. Non-profitable units are retired based on failure to recover fixed operating costs. AuroraXMP utilizes the Cost of New Entry (CONE) method for capacity expansion and price determination. Peak credit of 100% is applied to thermal generation units while wind and solar have peak credit multipliers of 15% and 50%, respectively.

Zonal Simulation

As discussed earlier in this section, IMPA uses AuroraXMP to solve zonal energy prices for large geographic regions. The reason for solving large regions is to capture the full impact of policies (EPA rules, legislation, renewable portfolio standards, etc.) as well as impacts of commodity price swings (natural gas, coal, SO_2, NO_x, CO_2, etc.).

Figure 46 AuroraXMP Zonal Topography



Source: EPIS, Inc.

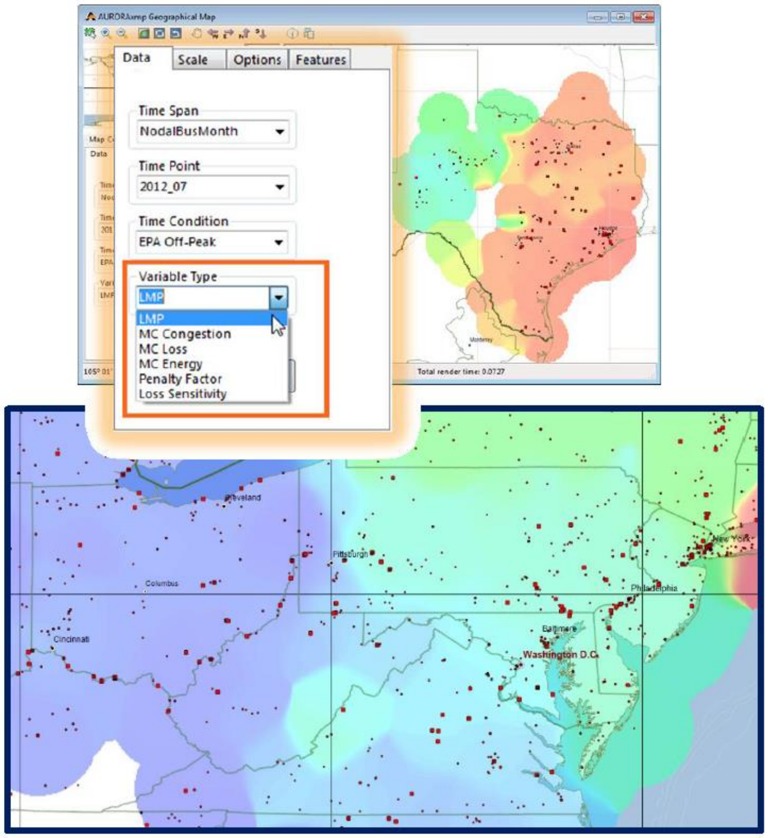
AuroraXMP calculates market prices for dozens of pricing hubs in the eastern interconnect. The model reports a multitude of items such as:

- Capacity and Energy Prices
- Unit Generation
- Fuel Consumption
- Emissions
- Marginal Units
- Zonal Imports/Exports

Nodal Simulation

AuroraXMP also includes a complete nodal security constrained economic dispatch (SCED) module that will calculate LMPs for hundreds of CPNODES.

Figure 47 AuroraXMP Nodal Topography



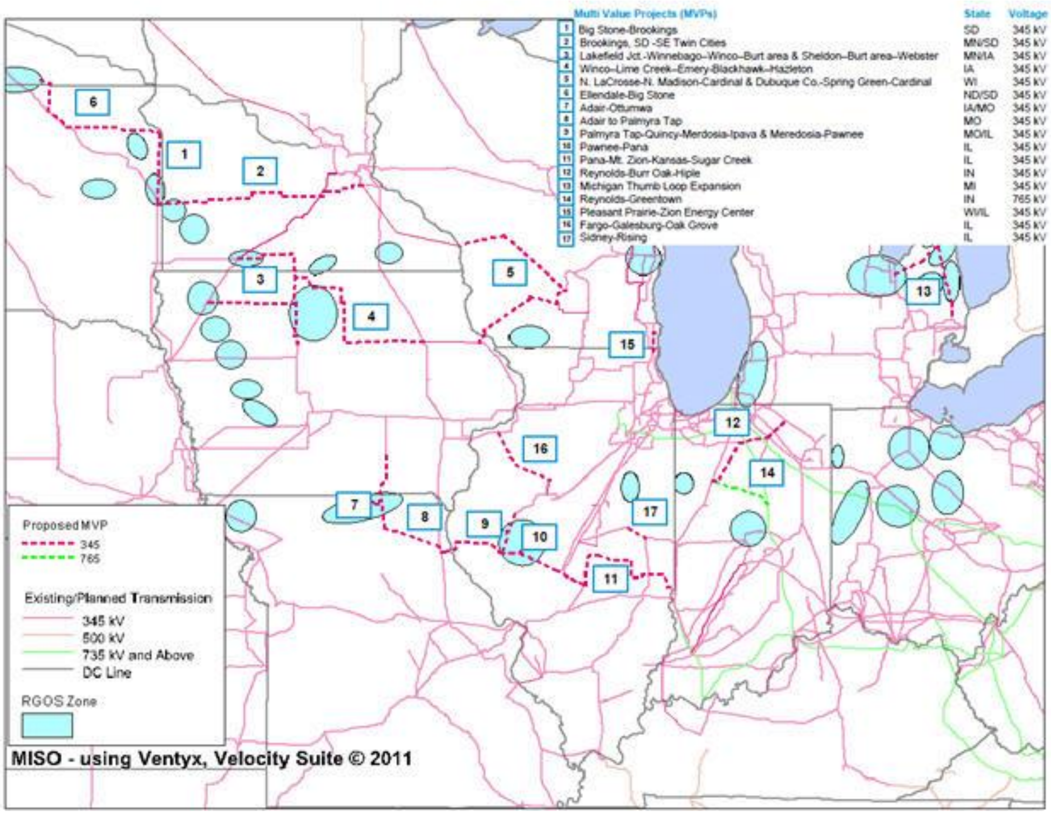
Source: EPIS, Inc.

The nodal module is more useful for running short term analysis where the transmission system buildout in the short term is fairly well known. For long term analysis, the detail required to build out a nodal system as well as the computational capital involved make it unsuitable for long term planning and it is not used in this analysis.

Transmission

The transmission transfer capability between zones is determined from the most recent AC load flow studies. Likely transmission additions such as the MISO MVP are added to the database to incorporate their impact on zonal transmission transfer capability and energy and capacity prices.

Figure 48 MISO MVP Portfolio



Source: MISO

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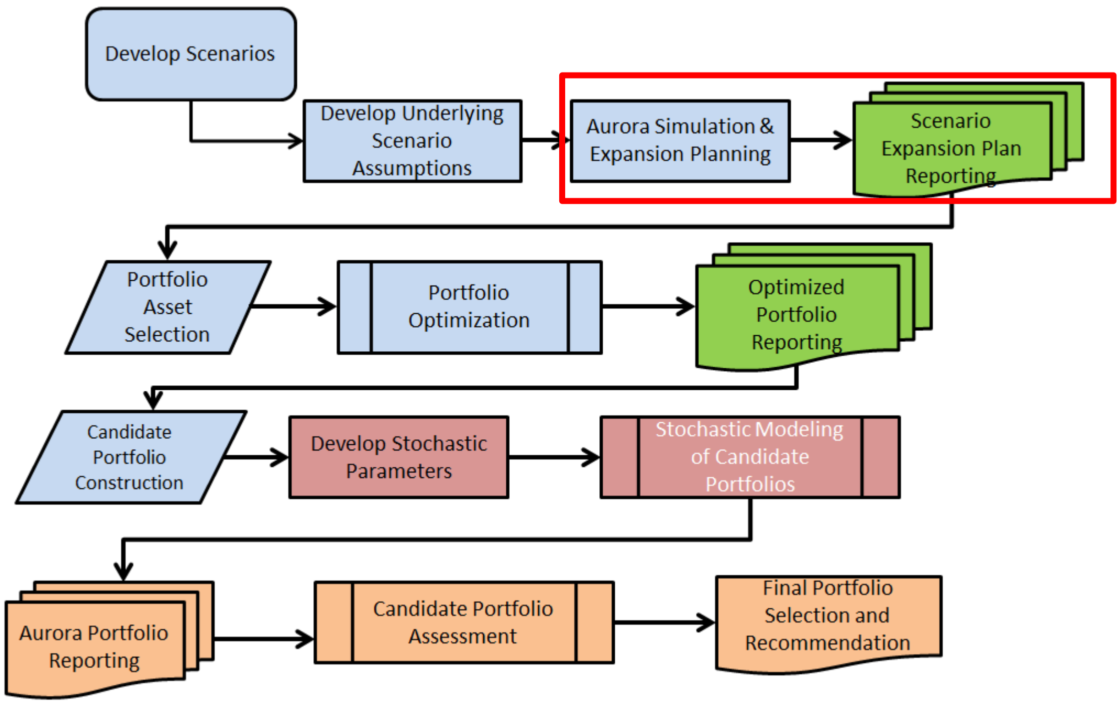
12 SCENARIO OPTIMIZATION AND RESULTS

This section outlines the results from the AuroraXMP expansion plan modeling under each scenario. Scenario development and the underlying assumptions for each scenario are covered in detail in Section 10.

Figure 49 IRP Flowchart – Scenario Optimization

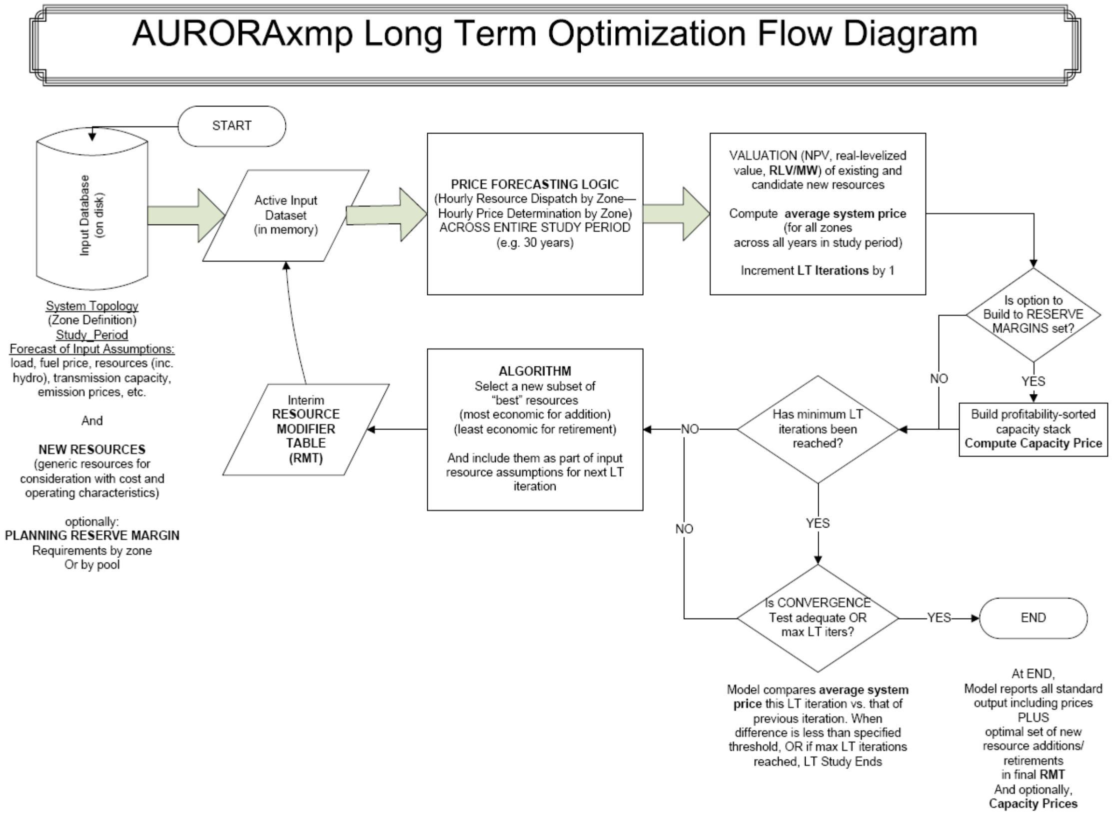


12.1 Zonal Capacity Expansion Module

Utilities create an IRP to provide a framework for prudent future actions required to ensure continued reliable and least cost electric service to their customers. An important part of this exercise is to evaluate the future resource needs to meet growing demand. This needs to be balanced and responsible for the stakeholders and the state regulatory bodies while adhering to IMPA's mission to supply power that is economic, reliable, and environmentally responsible. A primary driver of these decisions is long term market prices.

Within Aurora, the Long Term Optimization module iteratively retires and builds assets such that certain objectives, subject to user selection, are met. The two primary objectives are that the system cost is minimized and that area planning reserve margins are met. Other relevant objectives would be possible emissions constraints and/or renewable portfolio standards.

Figure 50 Zonal Capacity Expansion Module



Source: EPIS

Long Term Optimization Module – Objective Function

The optimal resource expansion strategy is based on an objective function subject to a set of constraints. The goal of the Long Term Optimization is to minimize the cost of meeting the required energy, demand and planning reserve requirements for a given balancing area, subject to any additional constraints to be entered.

The optimization answers the key investment decisions of:

- Technology: What to build/retire
- Timing: When to build/retire
- Location: Where to build/retire
- Quantity: How much to build/retire

The optimization can be run as either a traditional linear program (LP) or as a mix-integer program (MIP). Under the traditional LP the optimization seeks to maximize the value of the system by retiring those assets with negative net present values (NPV) and incrementally adding higher NPV assets such that load and reserve constraints are met. Under the MIP, the system can be optimized around either maximizing the value of the system or minimizing the cost of the system. IMPA utilized the MIP under the constrained by the minimal cost function for all of its expansion studies.

Long Term Optimization Module – Simulation Time

Capacity expansion planning models have very long time horizons (typically 20+ years). Aurora models all hours, but does allow for sampling of hours. While simulating every hour of every day may be useful for portfolio modeling and risk modeling, there is less value in doing so for long term optimizations, particularly when the entire eastern interconnect is being modeled. IMPA's modeling efforts modeled every other hour, four days a week, every other week. In IMPA's experience this balanced the trade-offs between model precision and computational intensity.

IMPA utilizes desktop PC workstations with 32 GB of RAM, 64-bit operating system, and a 3.6 GHz clock speed to run the long term optimizations.

12.2 NEW SUPPLY-SIDE OPTIONS

Existing Supply Resources

All IMPA-owned units were given the opportunity to retire in the capacity expansion runs. This is performed by allowing the expansion model to opt to retire an existing resource and replace it with other alternatives. Allowing IMPA's jointly owned units the opportunity to retire in the zonal runs allows the entire unit to be removed from the supply stack in lieu of IMPA's portion of the unit being unilaterally retired.

New Supply Resources

The purpose of an IRP is to assist the company in determining its future generation requirements at a basic needs level, not to select the specific unit type and model. The selection of the actual manufacturer and model to construct would be determined in the bid and project development process. As IMPA has a strategic preference towards proven technologies, carbon sequestration technologies were not included as resources options in this IRP.

Generating resources considered in this study include:

- Advanced combined cycle (CC) units
- Advanced gas-fired combustion turbines (CT)
- Aero-derivative combustion turbine
- Coal-fired steam generation
- High efficiency internal combustion (IC) units
- Nuclear
- Utility Wind
- Utility PV Solar

Capital costs, operating costs and operating characteristics for the thermal resources were taken from the EIA *Annual Energy Outlook 2016*. These baseline values are shipped with AuroraXMP as a data input. In addition, EPIS makes adjustments to the baseline values that account for items such as tax credit eligibility and local labor cost assumptions for major build areas as defined by the EIA's Market Model Supply Regions. Finally, IMPA then performs due diligence on this data and makes any adjustments deemed necessary. These adjustments are generally done based on IMPA discussions with industry contacts on installed costs for various generation types.

Figure 51 EIA Supply Regions

Source: EIA

IMPA considered asset builds across all supply regions with a MISO or PJM overlap with a preference on geographic proximity to IMPA load zones. In other words, assets that were built in MRO West (MISO North) were considered, but only in the absence of a comparable asset in RFC West (MISO Central).

IMPA ran the zonal optimization studies for the three scenarios. These runs produced three distinct zonal expansion plans optimized for each scenario. As more fully discussed in Section 13, this, in turn, generates a list of eligible assets for selection for IMPA to create an optimized "candidate portfolio." The following sections briefly outline the results of the expansion study on a zonal level.

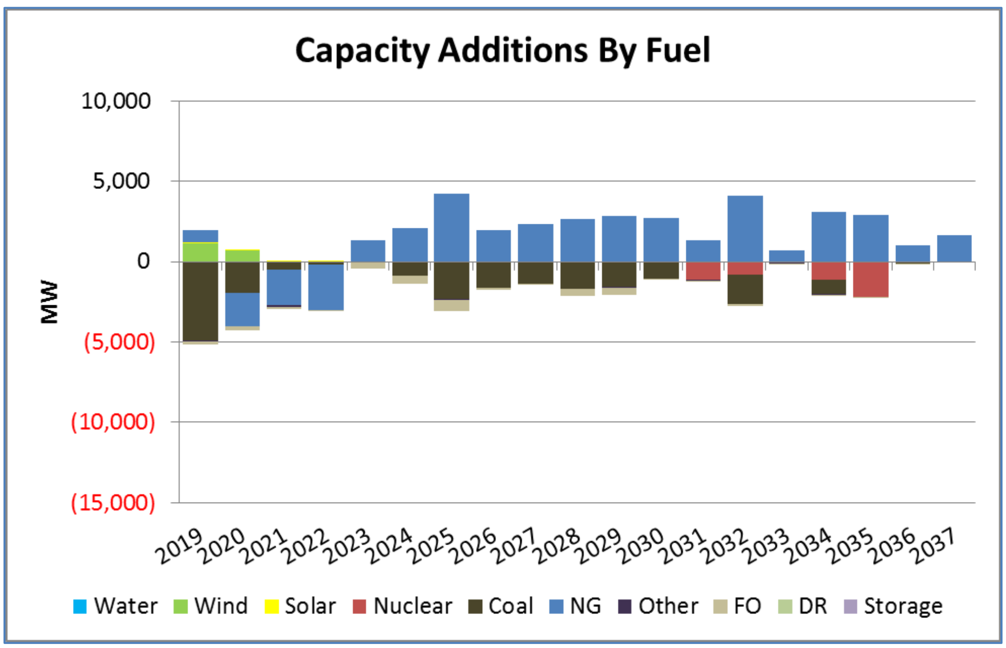
12.3 Base Case Expansion Results

The following outlines the modeling outcomes under the assumptions set forth in section 10.3. In summary, the IMPA Base Case sees little in the way of material asset retirements despite the introduction of a carbon tax regime in 2026. Ultimately, with muted load growth and price support from a combination of energy rents and/or capacity rents, the lowest cost solution is leaving more efficient coal units on-line as capacity resources while newer, more efficient generation is built "underneath" those older units in the generation stack.

12.3.1 MISO Expansion Results

The figure below illustrates the modeled expansion by fuel for MISO over the years studied. In the early years of the study, the MISO market is expected to see net retirements with a bulk of these retirements coming from coal fired assets.

Figure 52 Base Case MISO Capacity Expansion/Retirements by Fuel

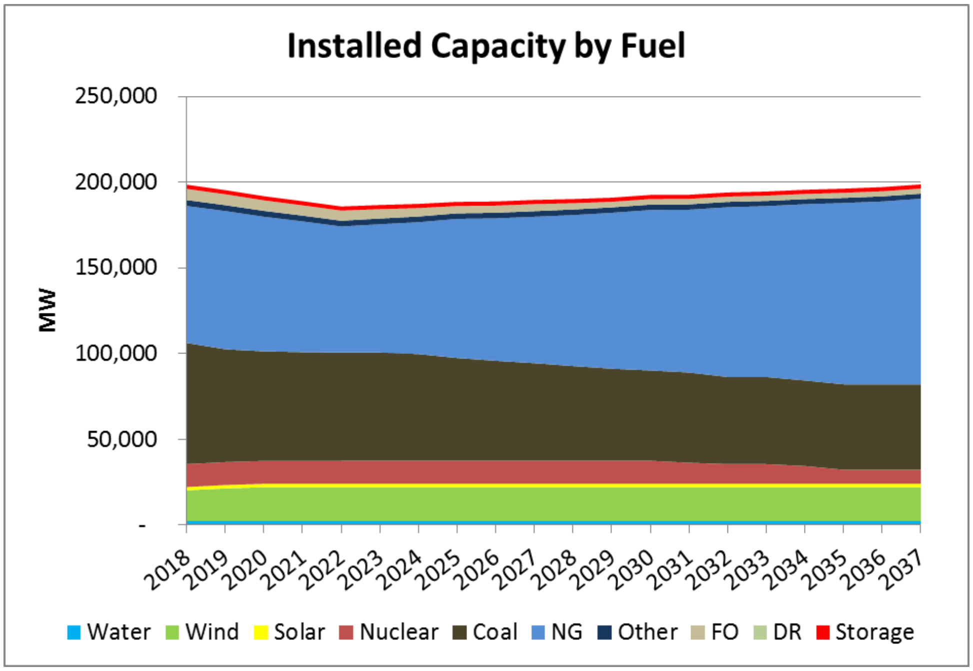


2023 becomes the first year of net capacity expansion with natural gas driving a bulk of the expansion. With tax credits for renewable sources of generation being phased out in the Base Case, natural gas units become the most competitive source of new generation.

When visualized by total installed capacity, the decreasing relevance of coal becomes more apparent, with coal shrinking from about 36% of installed capacity to roughly 25% of installed capacity by the end of the study period.

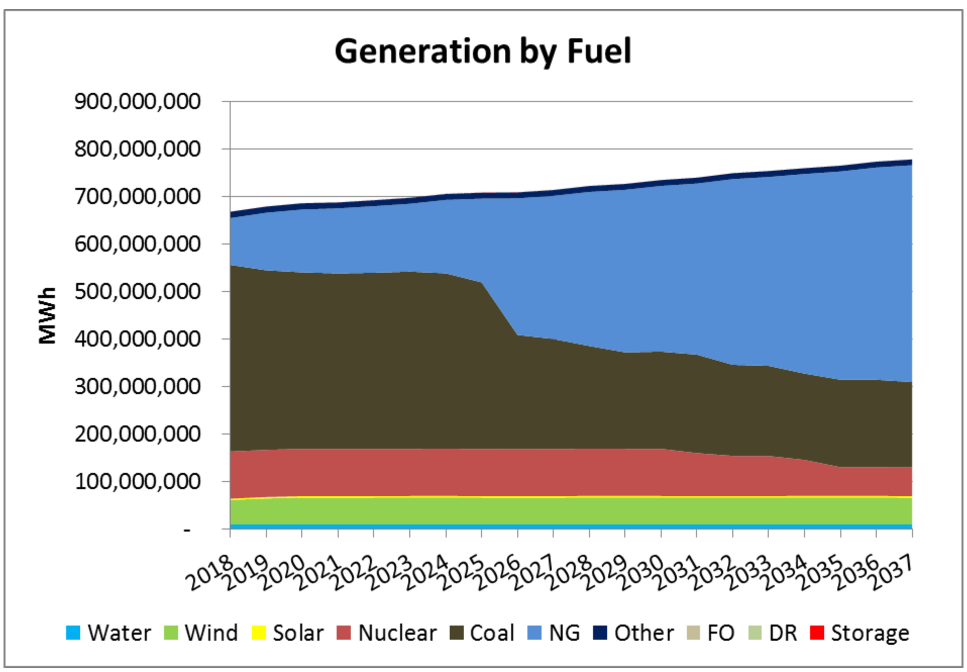
There is a lack of renewable expansion due to a combination of the sun setting of renewable tax credits and high reserve margins seen in the Base Case.

Figure 53 Base Case MISO Installed Capacity by Fuel



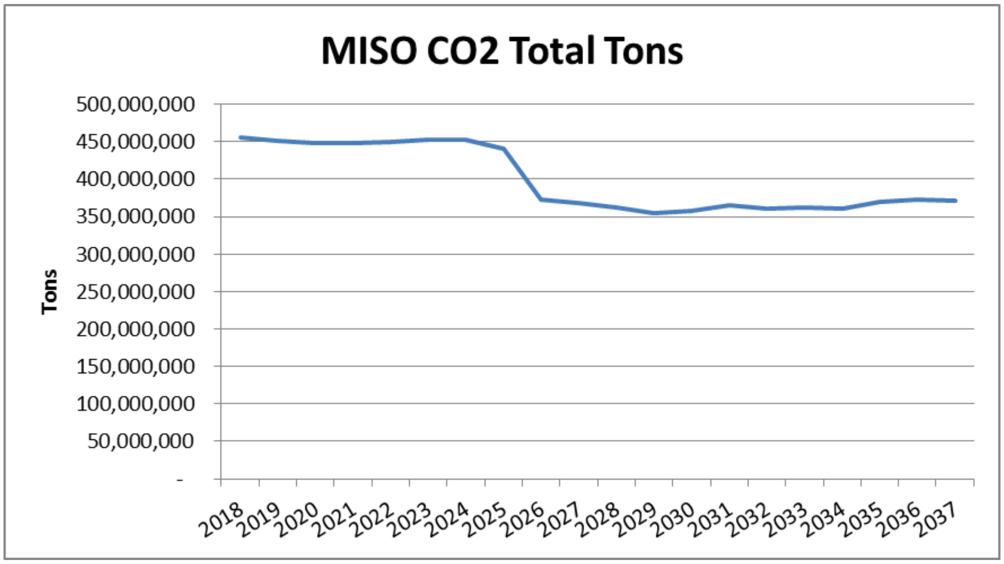
Coal's declines, however, are more dramatic in terms of generation. A large part of this is driven by the assumed carbon tax that materializes in 2026 at $20/ton. As modeled, coal resources are essentially left as capacity resources while new combined cycle generation picks up the base load responsibility.

Figure 54 Base Case MISO Total Generation by Fuel



The impacts of a \$20/ton carbon tax can be seen in the MISO footprint emissions (CO_2, mercury, NO_x and SO_2). Prior to 2026 the Base Case sees roughly 450 million tons of CO_2 emissions in the MISO footprint. By the end of 2026 CO_2 emissions in MISO fall by about 100 million tons per year.

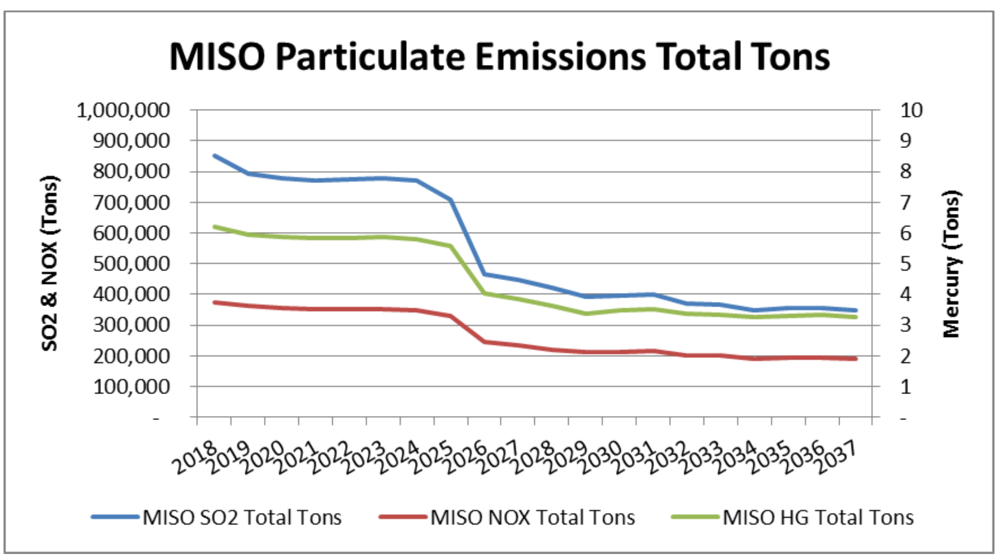
Figure 55 Base Case MISO CO_2 Emissions



There is a gradual increase in later years as natural gas becomes increasingly important as a source of generation however.

Commensurate with declines in CO_2 emissions are declines in mercury, NO_x, and SO_2 but without the corresponding increase in later years due to generally lower emission rates on gas fired generation.

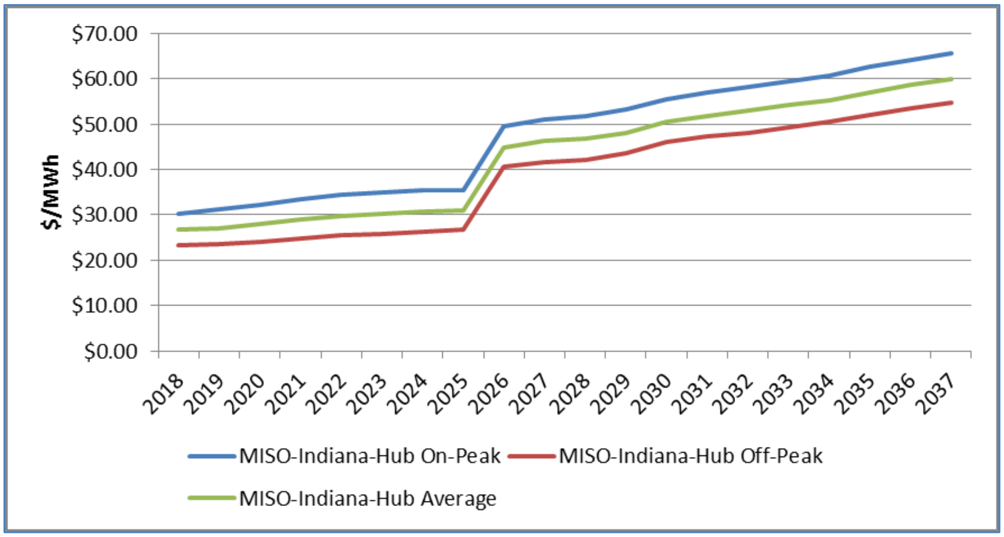
Figure 56 Base Case MISO Total Particulate Emissions



Despite a \$20/ton CO_2 tax and a gradual retirement of smaller, less efficient coal fired generation the resulting impact to wholesale power prices is relatively muted. The following figures illustrate the modeled prices for the major power trading hub of interest within the MISO footprint: Indiana Hub.

A \$20/ton CO_2 tax in 2026 is expected to have a roughly \$14/MWh price impact on wholesale power prices.

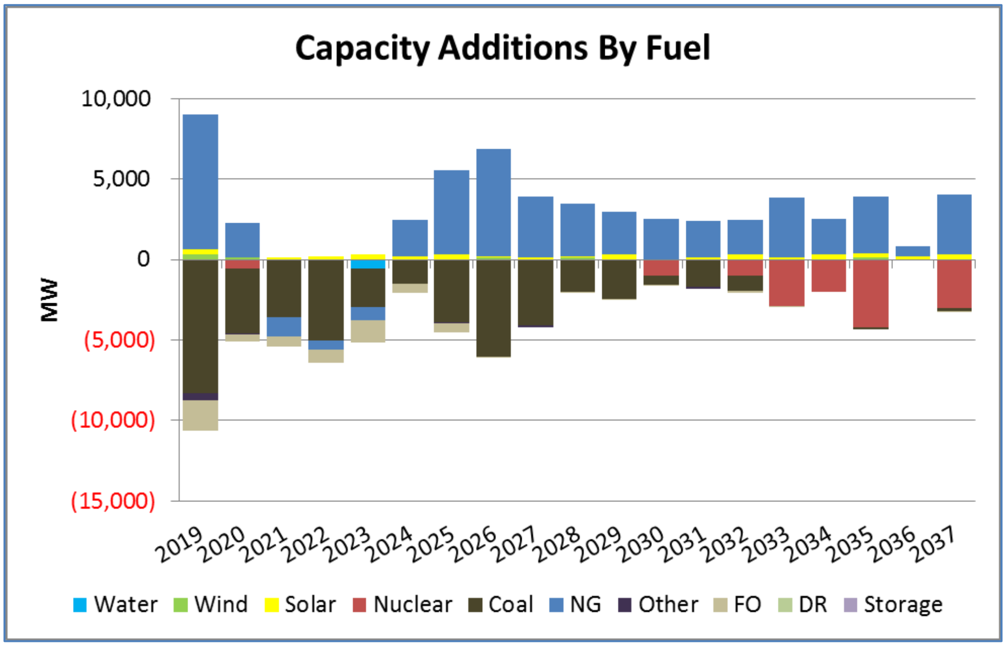
Figure 57 Base Case Indiana Hub Prices



12.3.2 PJM Expansion Results

A similar expansion is expected in PJM under IMPA's Base Case assumptions as the following figure illustrates.

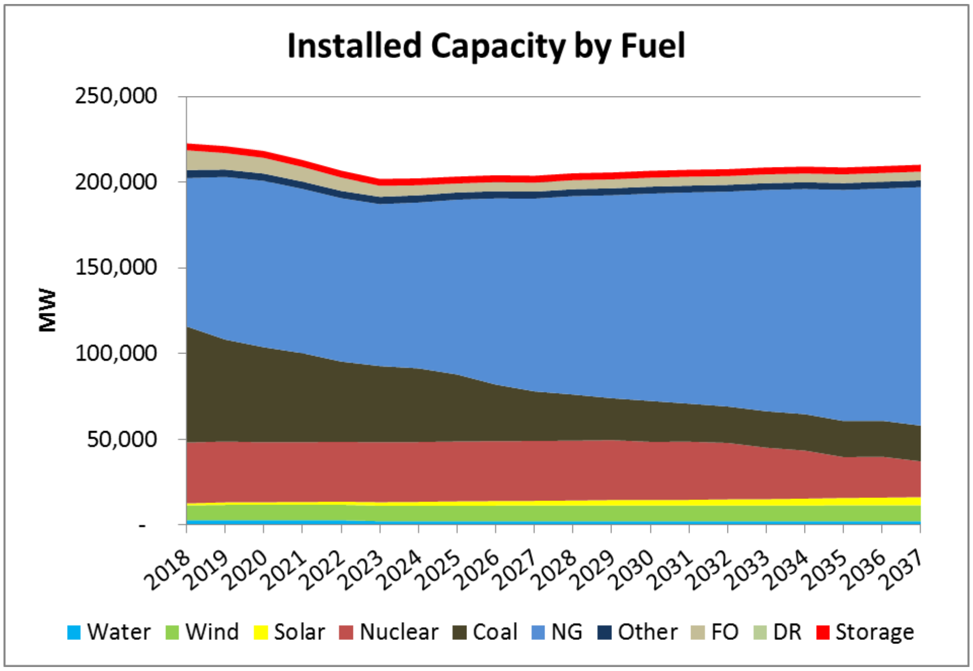
Figure 58 Base Case PJM Capacity Expansion/Retirements by Fuel



In 2019, PJM sees a wave of coal retirements and subsequent CC/CT additions, while the subsequent years are effectively years of net retirements. As carbon pricing comes in the pace of retirements reaccelerates and that capacity is replaced with natural gas fired assets. IMPA assumes that existing nuclear capacity retires at the end of existing license expiration with no additional extensions.

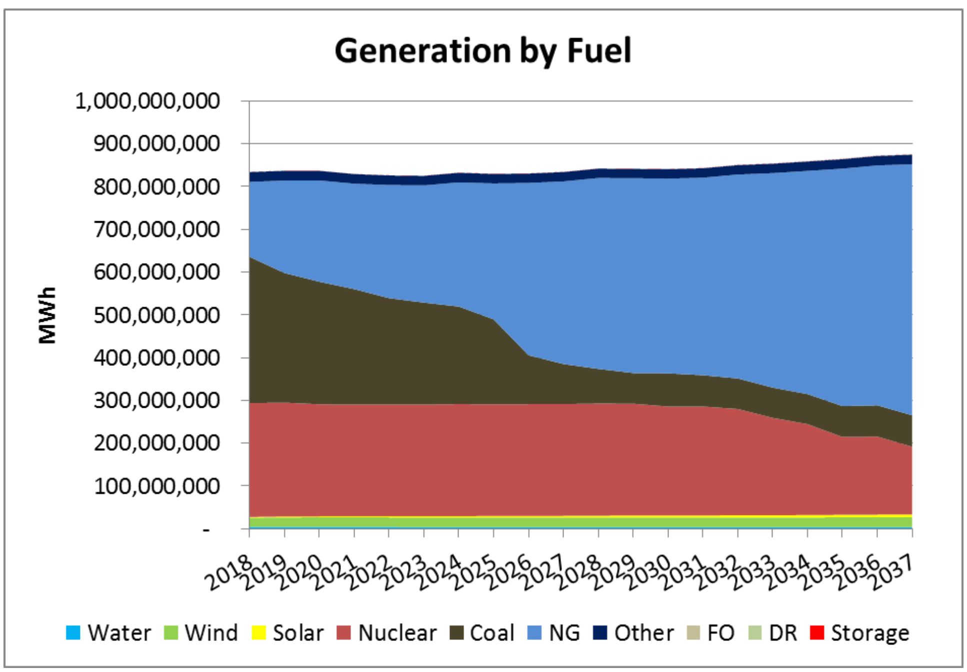
In terms of total installed PJM capacity, the PJM footprint sees a more dramatic reduction in coal fired assets than MISO.

Figure 59 Base Case PJM Installed Capacity by Fuel



On an energy supply basis, coal's decline is also notable as carbon phases in. While coal represents about 30% of installed capacity in PJM in 2018, it is 41% of energy. In a $20/ton carbon environment, these figures drop to 16% of installed capacity and 14% of energy.

Figure 60 Base Case PJM Generation by Fuel



Similarly PJM sees lower emissions produced over the study, with the main catalyst being a shift away from coal fired generation as baseload resources.

Figure 61 Base Case PJM CO_2 Emissions

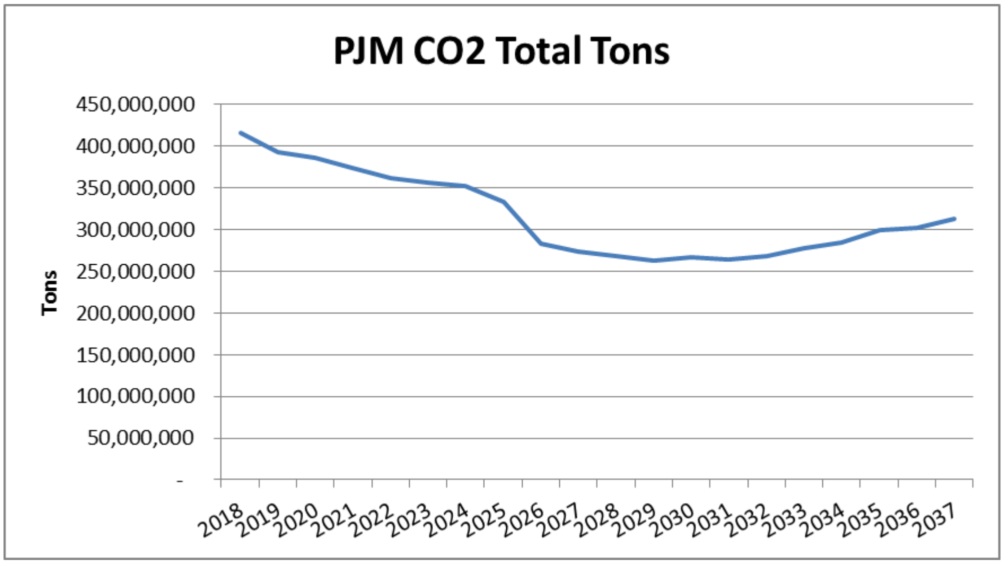
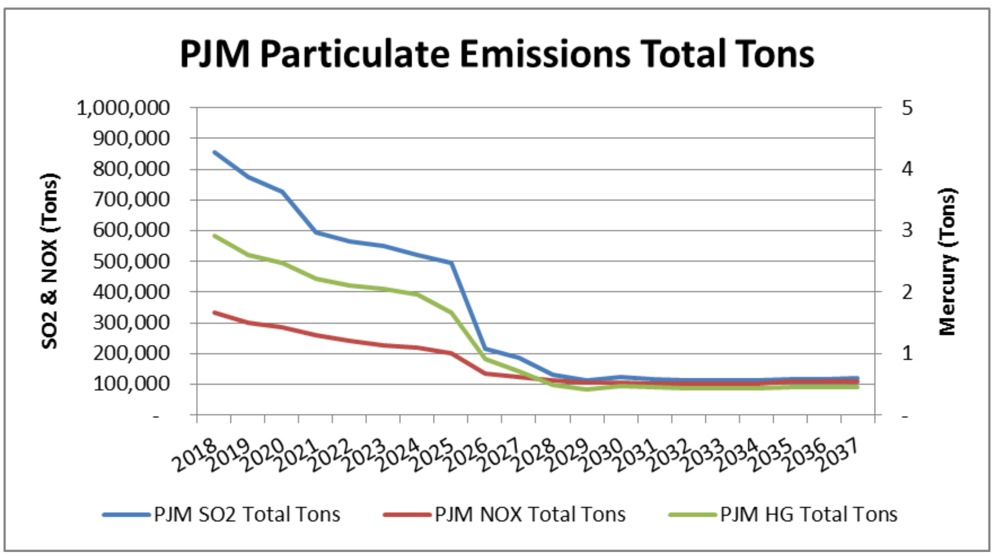
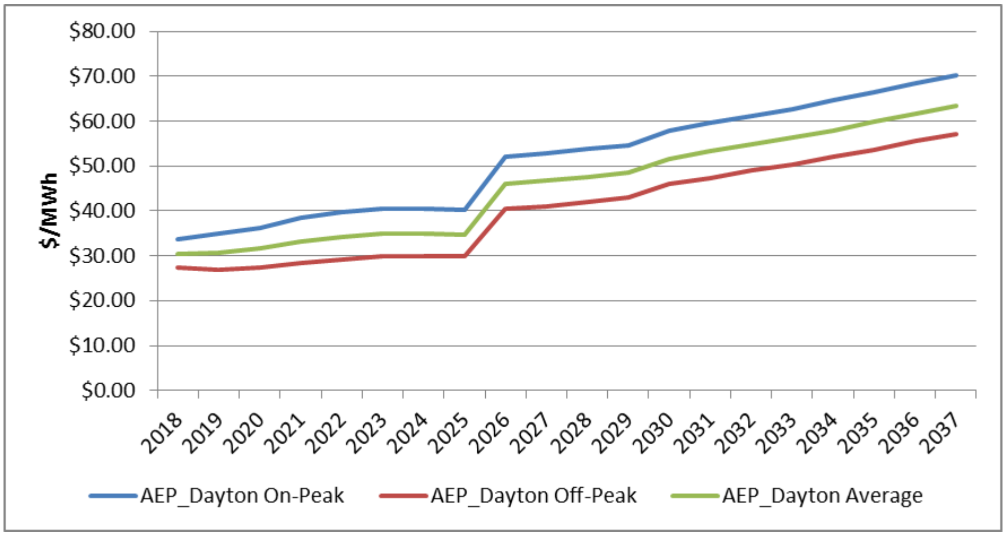


Figure 62 Base Case PJM Total Particulate Emissions



Pricing at AD Hub is slightly less sensitive to carbon taxation and experiences an $11/MWh increase in wholesale power prices as a result of the $20/ton CO_2 tax.

Figure 63 Base Case AD Hub Prices



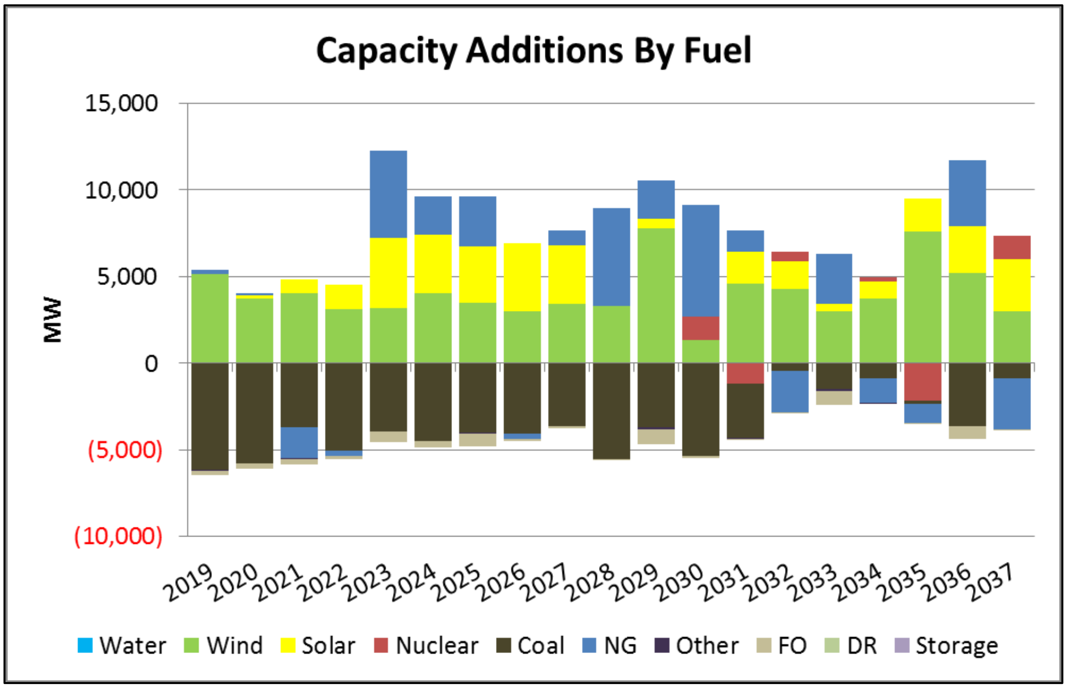
12.4 Green Case Expansion Results

The following outlines the modeling outcomes under the assumptions set forth in section 10.4. In summary, the IMPA Green Case sees a dramatic increase in the number of retirements and pace of new generation construction. The IMPA Green Case assumes a \$40/ton CO_2 tax in 2026 (2x the Base Case assumption), and an RPS of 20% of energy supplied by 2030. As a result, the modeled expansion has to both aggressively de-sensitize the generation stack to carbon taxes, but also comply with an RPS mandate.

12.4.1 MISO Expansion Results

The figure below illustrates the modeled expansion by fuel for MISO over the years studied. In the early years of the study, the MISO market is expected to see net retirements with a bulk of these retirements coming from coal fired assets.

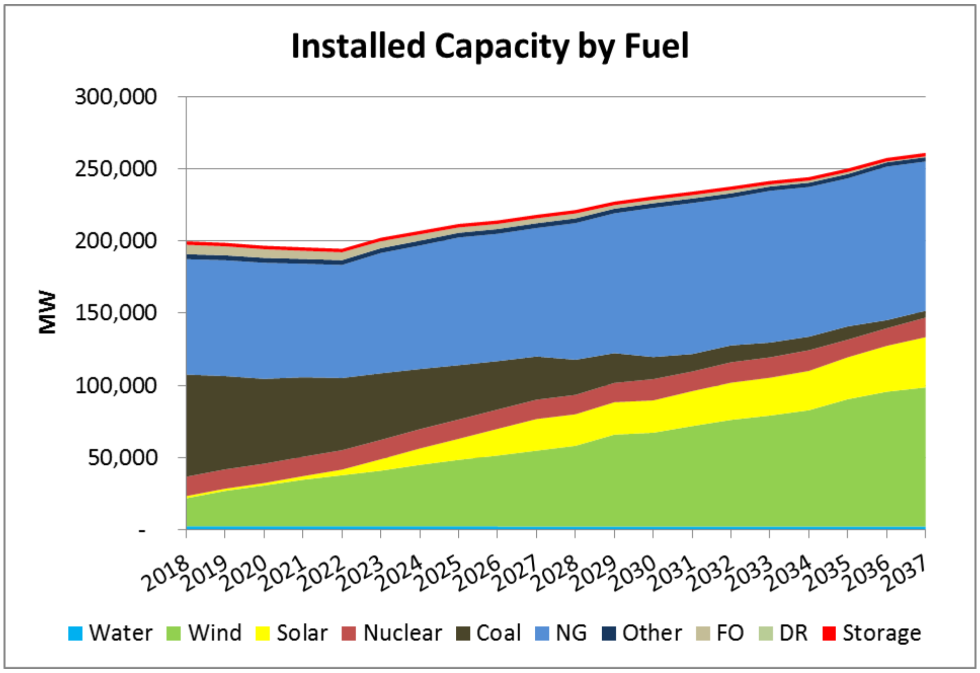
Figure 64 Green Case MISO Capacity Expansion/Retirements by Fuel



Under the Green Case assumptions, coal is quickly relegated in favor of wind, solar, and natural gas generation. Nuclear capacity is built in this scenario, but the high capital costs limit it to replacing previously retired units.

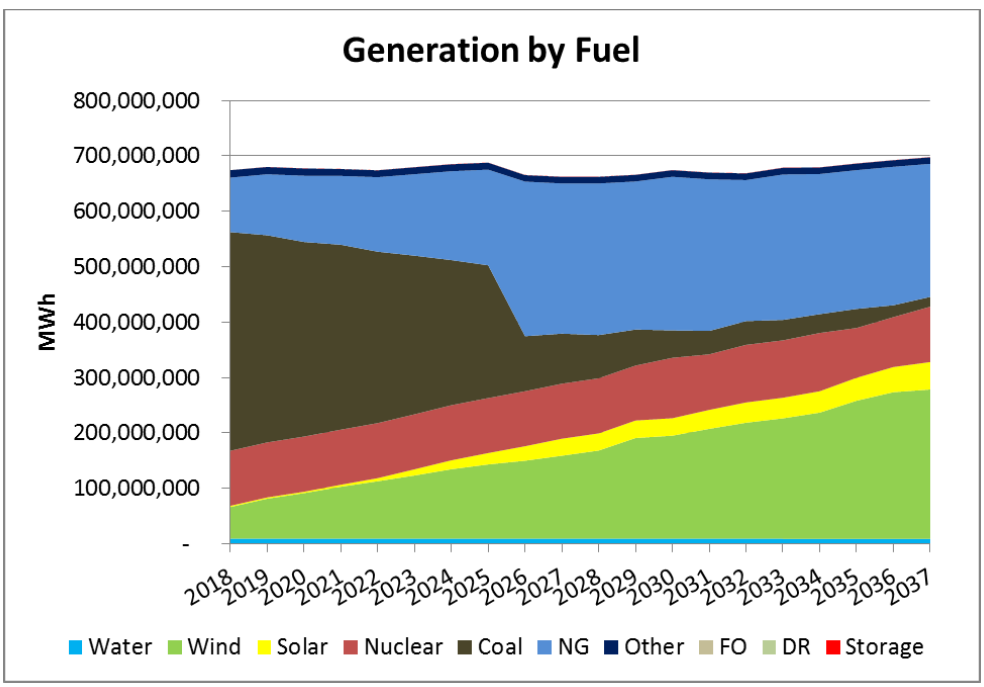
When illustrated over the study period and by installed capacity by fuel, this shift in generation preference is more evident. Natural gas builds (i.e., combined cycles) begin prior to the carbon tax implementation date of 2026 while wind and solar grow progressively over the study in order to meet and maintain the 20% RPS by 2030.

Figure 65 Green Case MISO Installed Capacity by Fuel



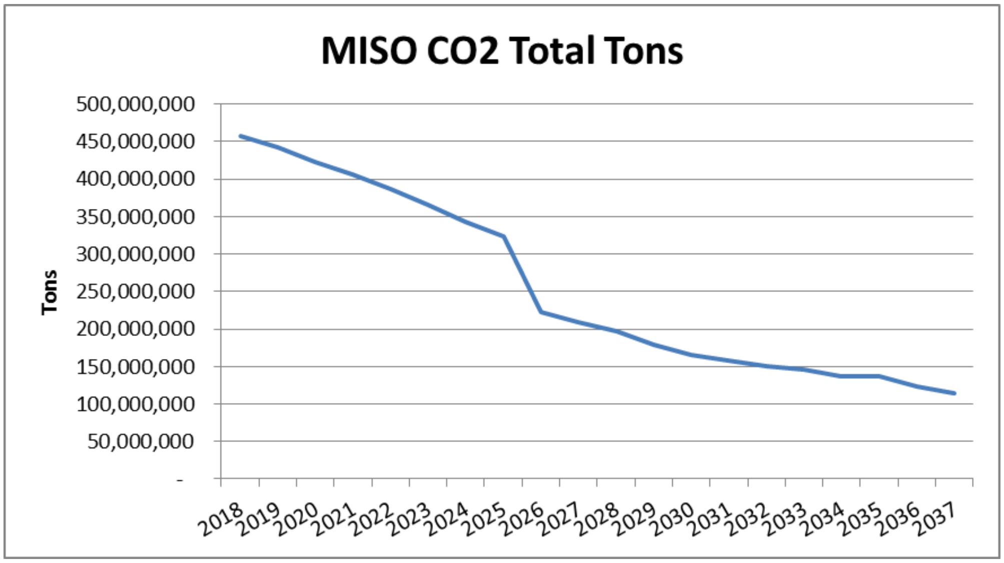
Coal generation steadily declines until 2026 at which point it sharply declines in the MISO footprint, being largely replaced by natural gas combined cycles, wind and solar.

Figure 66 Green Case MISO Generation by Fuel



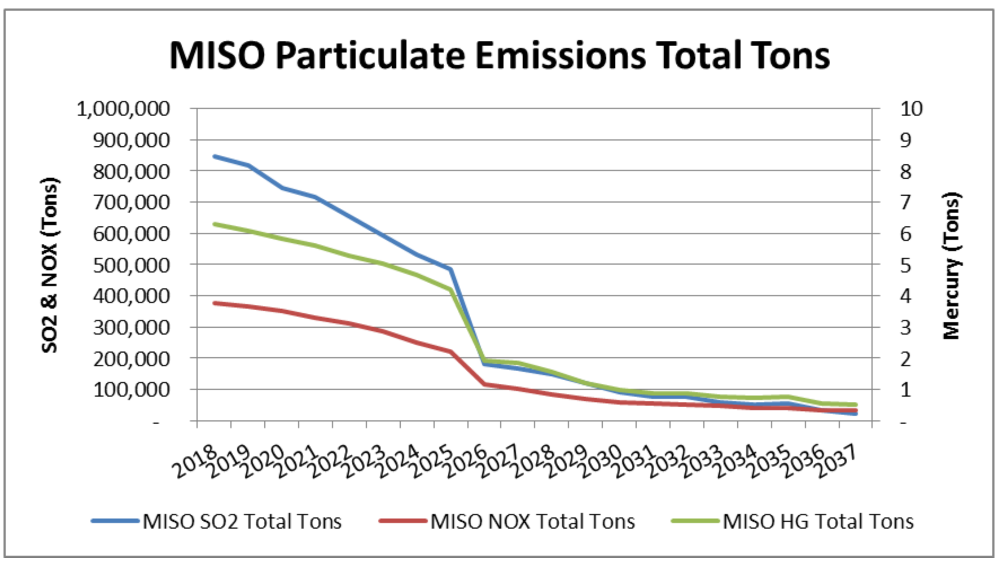
The dual impacts on emissions from a $40/ton CO_2 tax and a 20% RPS are notable. Initial CO_2 emissions are expected to be around 450,000,000 tons in MISO at the start of the study. This number declines, as shown below, to around 100 million tons by the end of the study.

Figure 67 Green Case MISO CO_2 Emissions



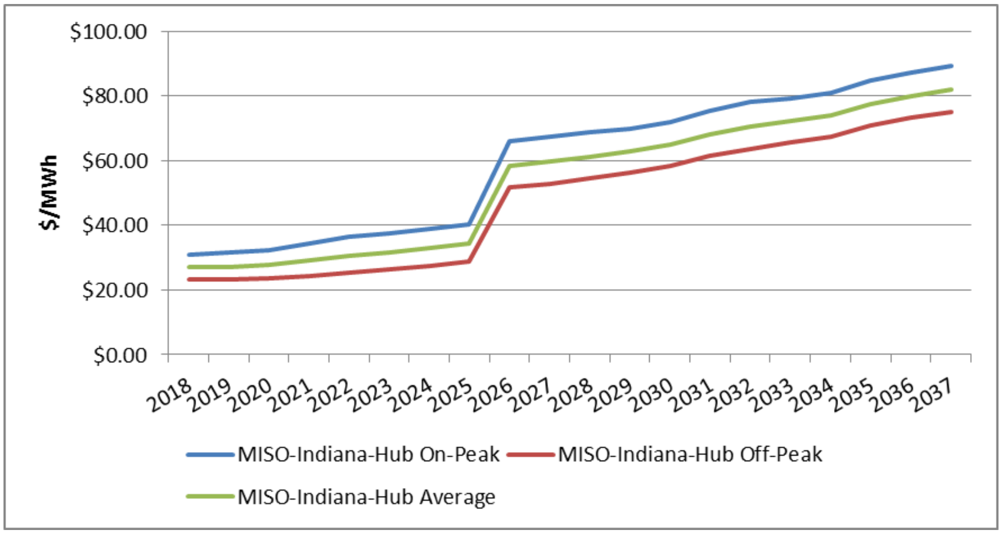
Impacts to particulate emissions are similar with SO_2 and mercury showing the largest declines.

Figure 68 Green Case MISO Particulate Emissions



Impacts on wholesale prices at Indiana Hub in the Green Case are quite notable, with power prices jumping $23/MWh year on year when the $40/ton CO_2 tax is implemented in 2026.

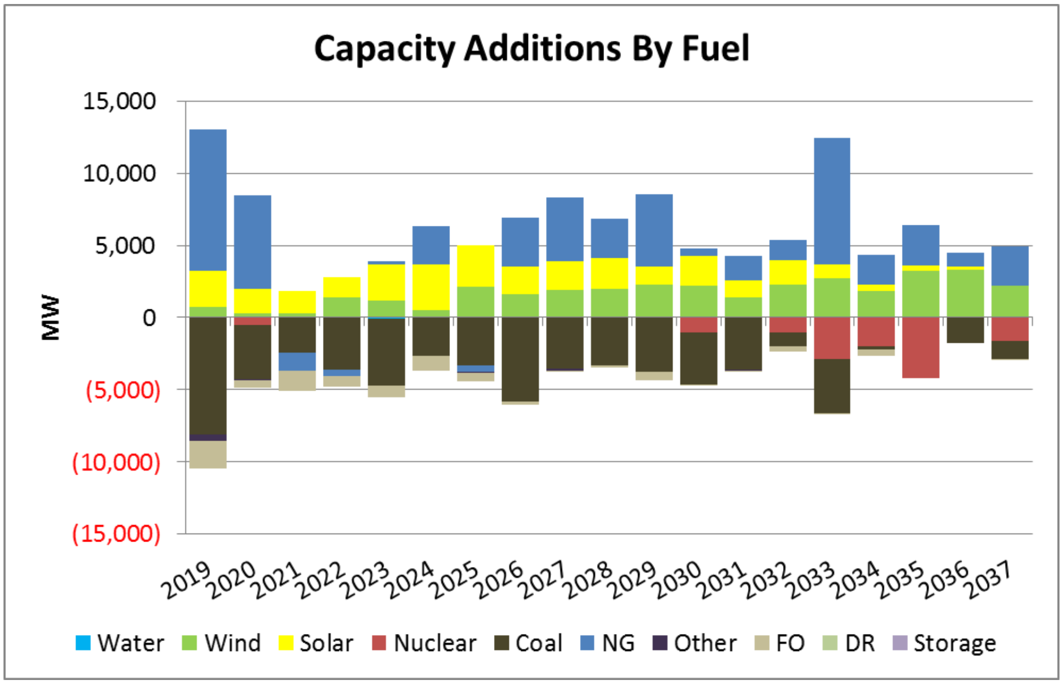
Figure 69 Green Case Indiana Hub Prices



12.4.2 PJM Expansion Results

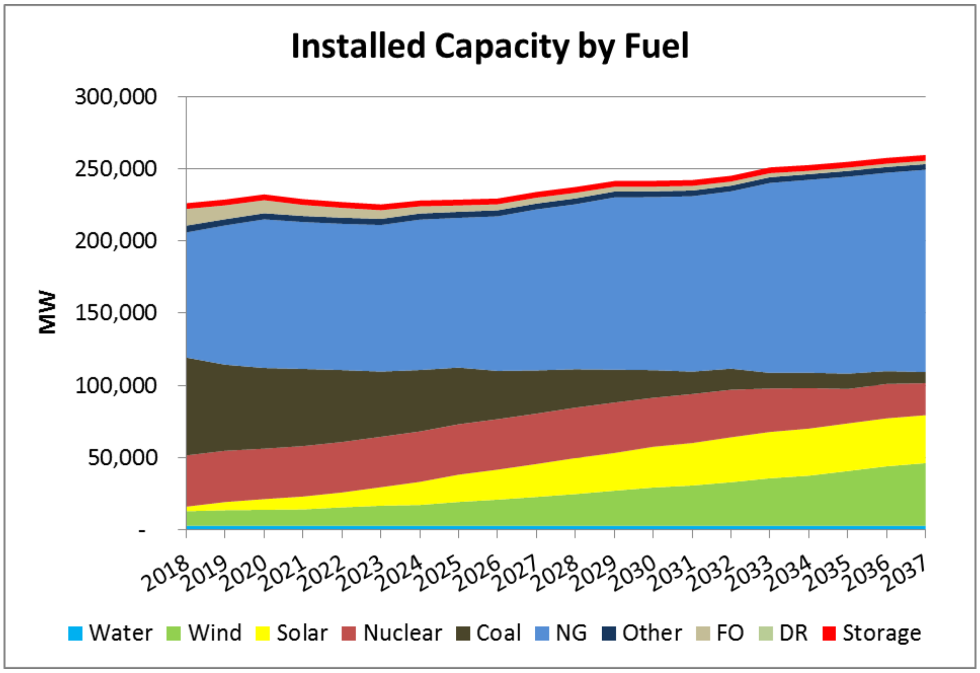
Expansion is similar under the Green Case in PJM, however there is a more aggressive initial retirement of coal fired generation and subsequent replacement with natural gas resources. Solar is the renewable of choice due to the better energy profile and somewhat lower capital costs in the east, whereas wind in the east is generally hampered by higher capital costs and lower capacity factors.

Figure 70 Green Case PJM Capacity Expansion/Retirements by Fuel



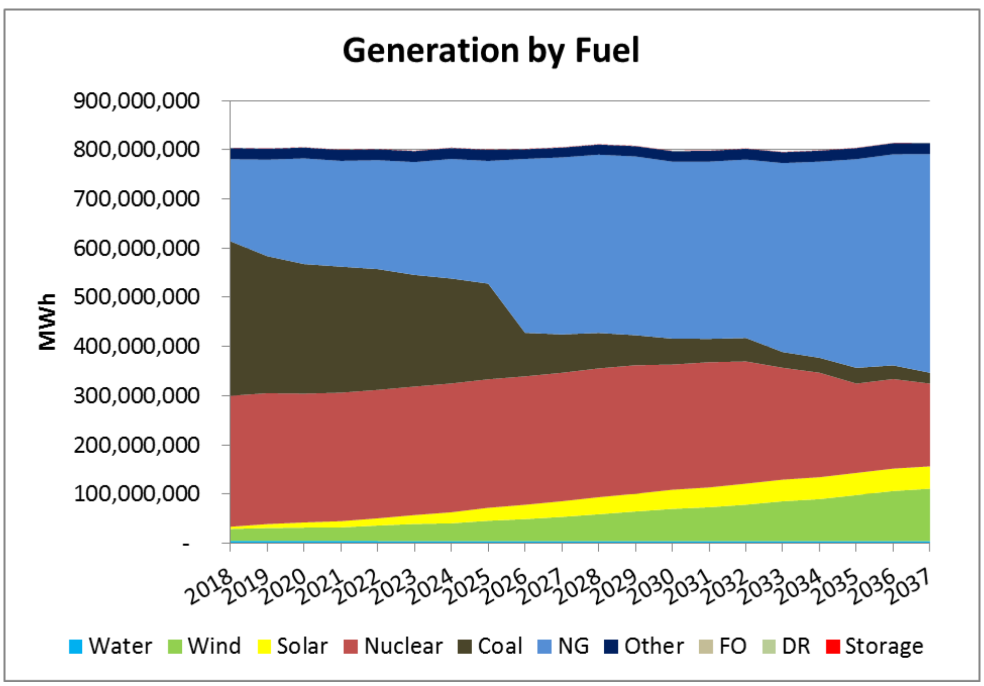
PJM capacity expansion in terms of installed capacity shows a gradual reduction of coal in the supply stack and increases in solar, wind and natural gas fired capacity.

Figure 71 Green Case PJM Installed Capacity by Fuel



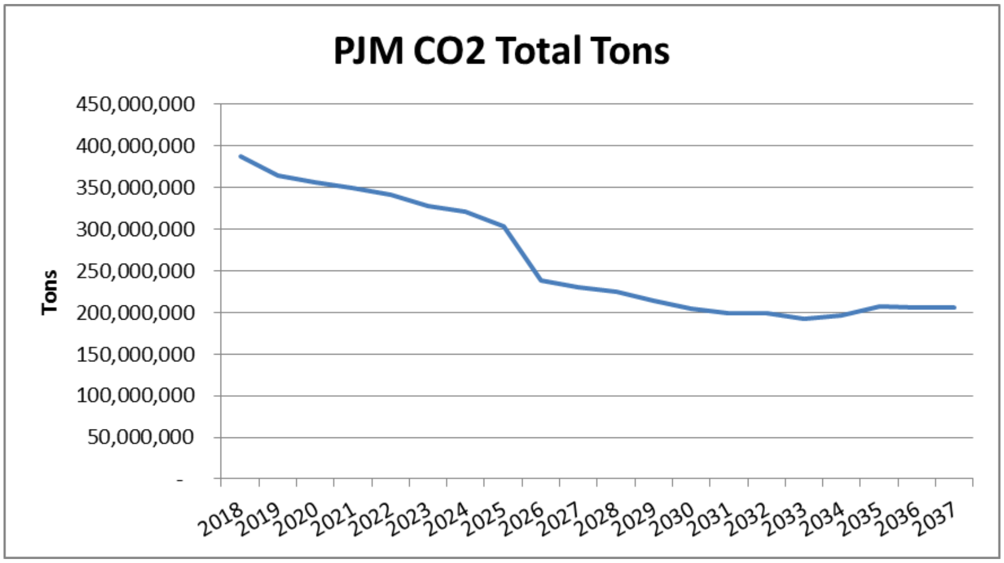
As expected, capacity reductions in coal means generation slack is picked up by alternatives. As was the case with the MISO expansion, natural gas is the primary source of displaced/retired coal generation.

Figure 72 Green Case PJM Generation by Fuel



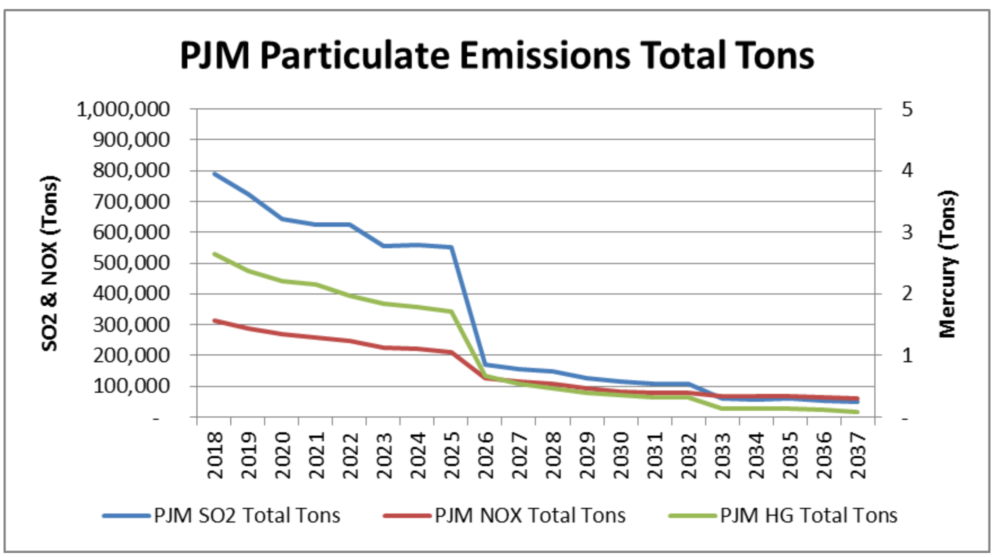
PJM CO_2 emissions under this supply stack are expected to fall from around 400 million tons to around 200 million tons over the course of the study. Unlike MISO however, reductions in CO_2 emissions slow in the outer years due to the need for economic natural gas generation. This is in contrast to MISO, where higher wind capacity factors improve the economics of non-subsidized renewable energy projects, thus allowing for ongoing reductions in CO_2 emissions.

Figure 73 Green Case PJM CO_2 Emissions



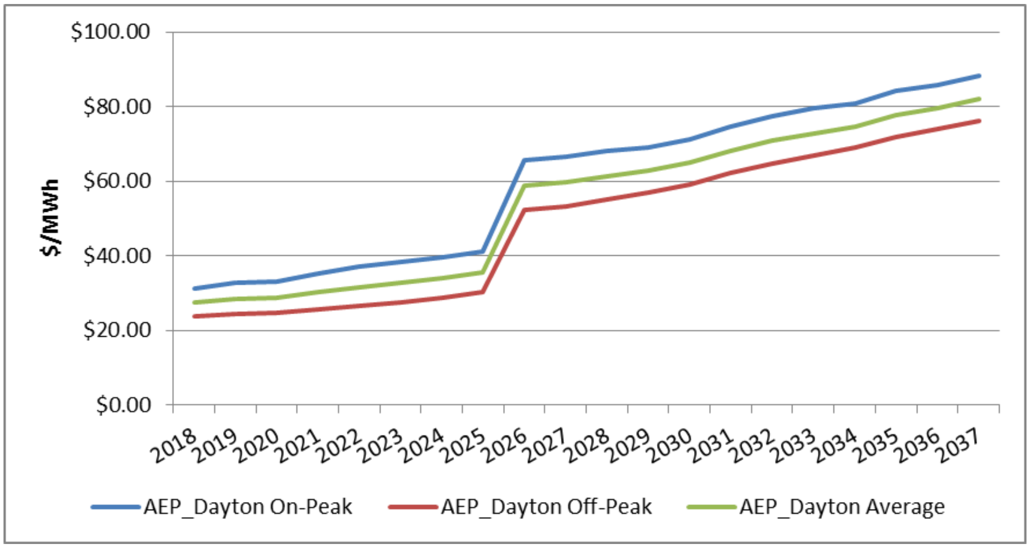
Particulate emissions in PJM follow a similar path as MISO under the IMPA Green Case with dramatic reductions in particulate emissions given the decreased reliance on coal fired generation.

Figure 74 Green Case PJM Particulate Emissions



Similar impacts are felt at other relevant trading hubs with AD Hub experiencing a $22/MWh increase year on year and PJM West Hub experiencing a $19/MWh increase. As was the case with the Base Case, impacts are felt less in PJM due to a larger base of installed nuclear capacity.

Figure 75 Green Case AD Hub Prices



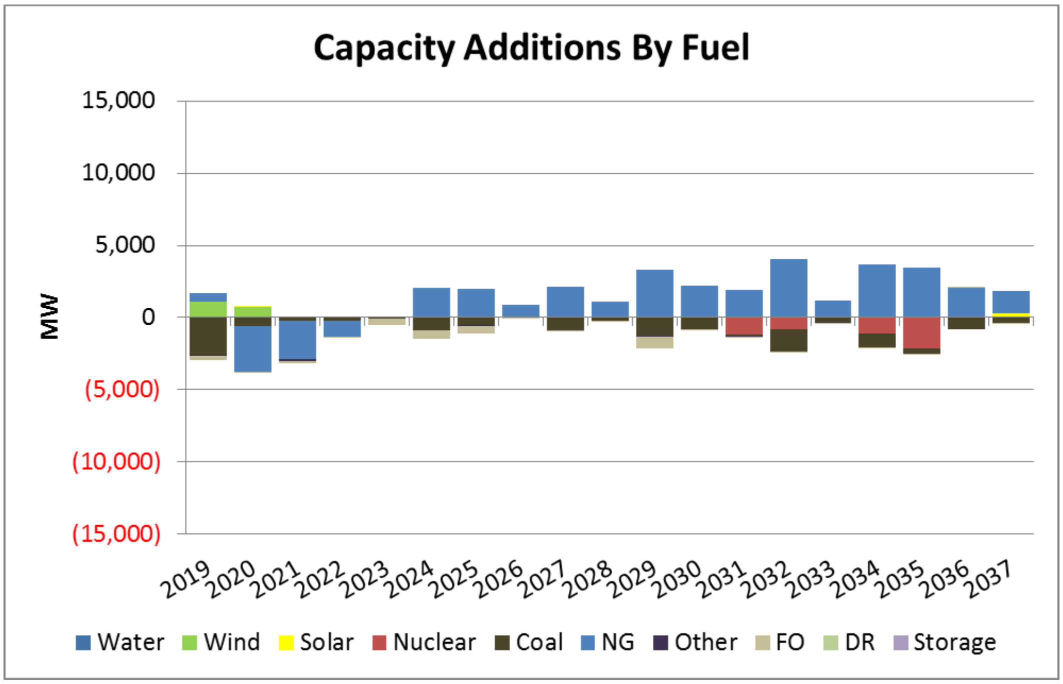
12.5 High Growth Case Expansion Results

The following outlines the results of the expansion study as run under the assumptions set forth in section 10.5. Perhaps the most critical difference in assumptions is the lack of any carbon tax implementation. A secondary assumption is that coal prices remain relatively low while natural gas prices revert to levels consistent with higher economic growth. Ultimately the landscape of the High Growth Case is one where coal maintains its share of the resource stack and new generation selection is not biased by any form of tax or subsidy.

12.5.1 MISO Expansion Results

The resulting MISO Capacity additions are shown in the figure below.

Figure 76 High Growth Case MISO Net Installed Capacity

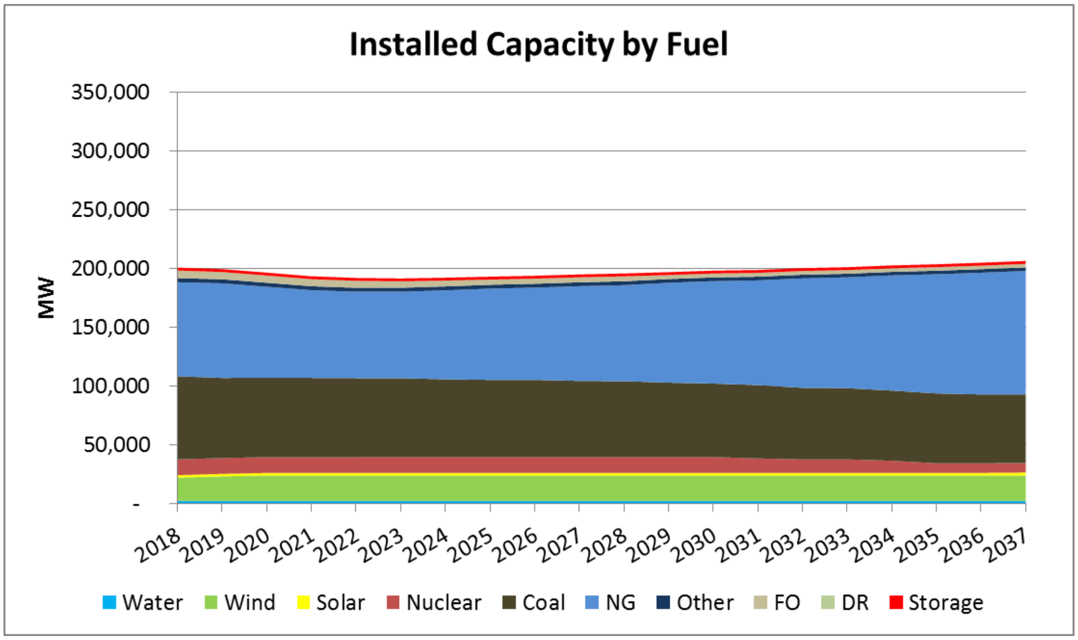


The relatively large number of natural gas retirements stem from older peaking units being retired, mostly originating in the southern region of the footprint. These units are then replaced as soon as permitted to meet the expected increase in load growth. The expansion plan essentially rebalances the MISO portfolio given the existing excess reserve margins. New resources, despite higher assumed load growth, are not needed until 2024. In this first year of MISO seeing net capacity additions, MISO adds roughly 2,000 MW of natural gas fired generation while retiring 900 MW of coal and 500 MW of older fuel oil peaking units.

Over time, the supply stack is expected to very gradually increase its reliance on natural gas generation.

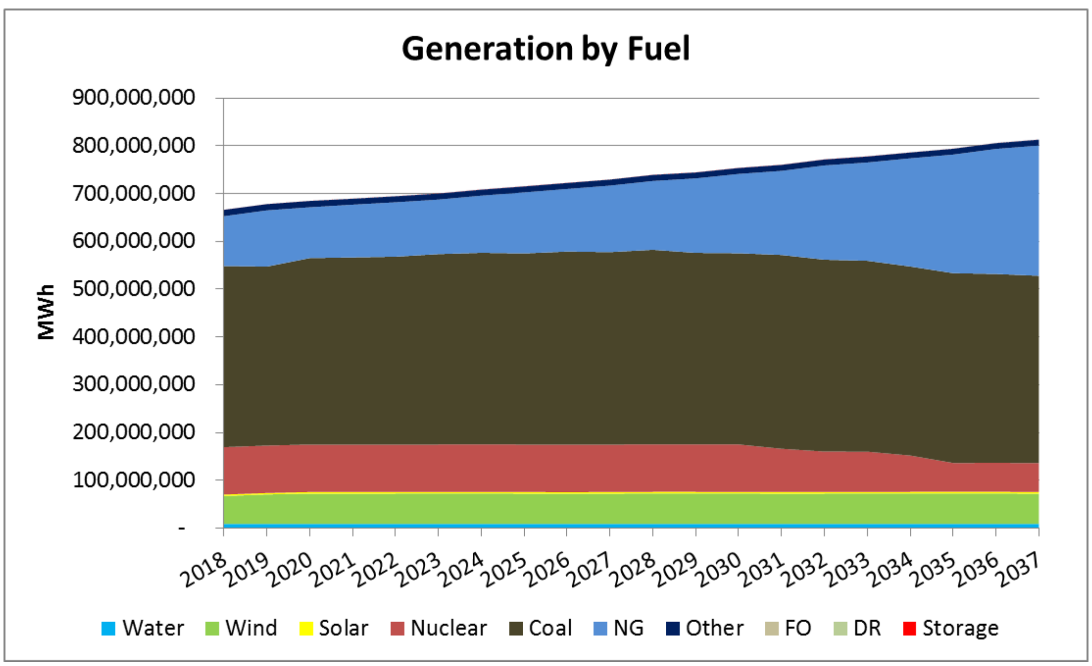
The following figure illustrates the installed MISO capacity under the High Growth Case.

Figure 77 High Growth Case MISO Total Installed Capacity



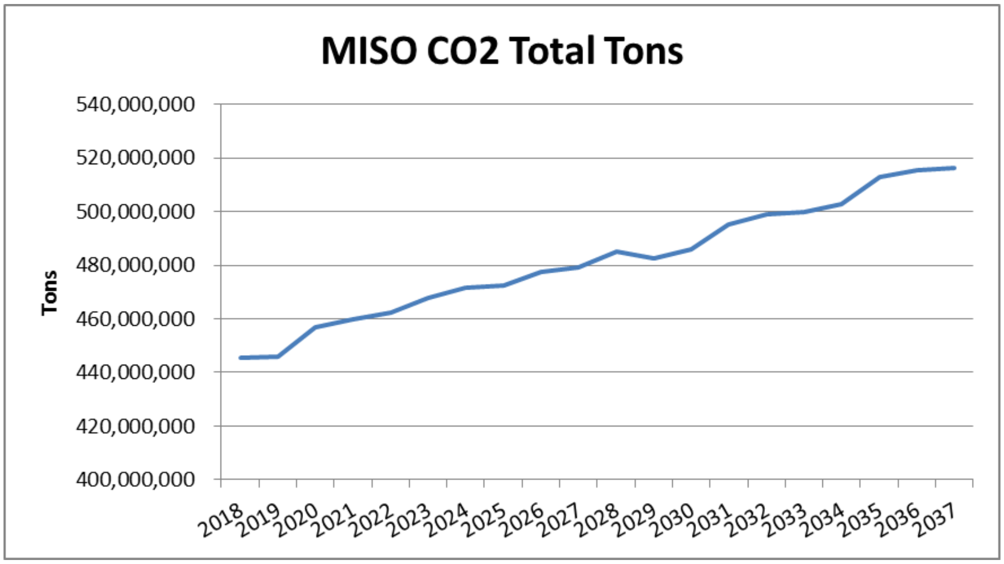
When viewed as total generation by fuel, below, the declines in coal are somewhat more pronounced, however still not as extreme as the Base Case or Green Case.

Figure 78 High Growth Case MISO Generation by Fuel



MISO emissions are generally expected to stay stable until later years when natural gas generation begins to take a more central role. Total CO_2 emissions for the MISO footprint during the study are shown below.

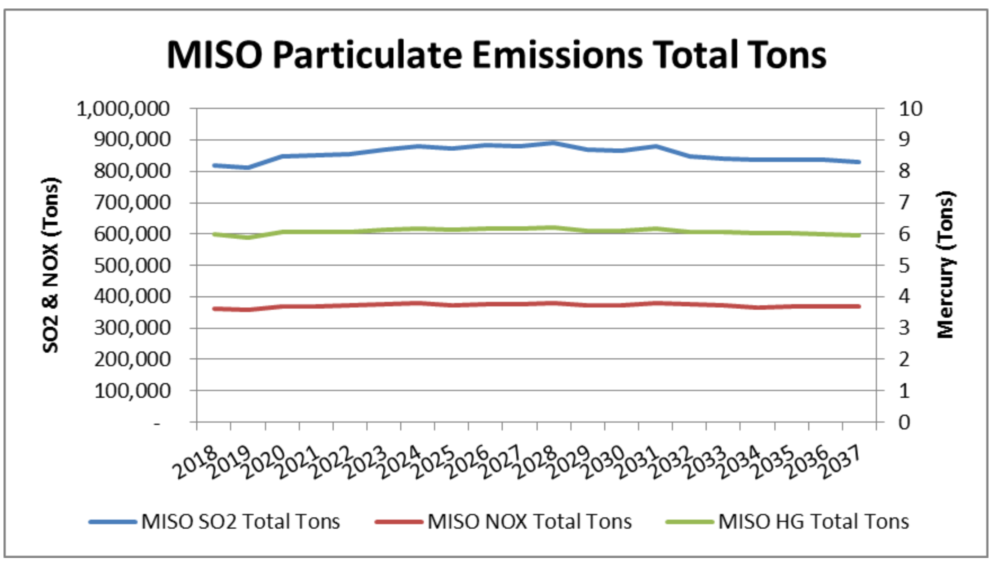
Figure 79 High Growth Case MISO CO_2 Emissions



As the High Growth Case has no CO_2 policy assumption, generation competes purely on economics. As a consequence, CO_2 emissions gradually increase over time.

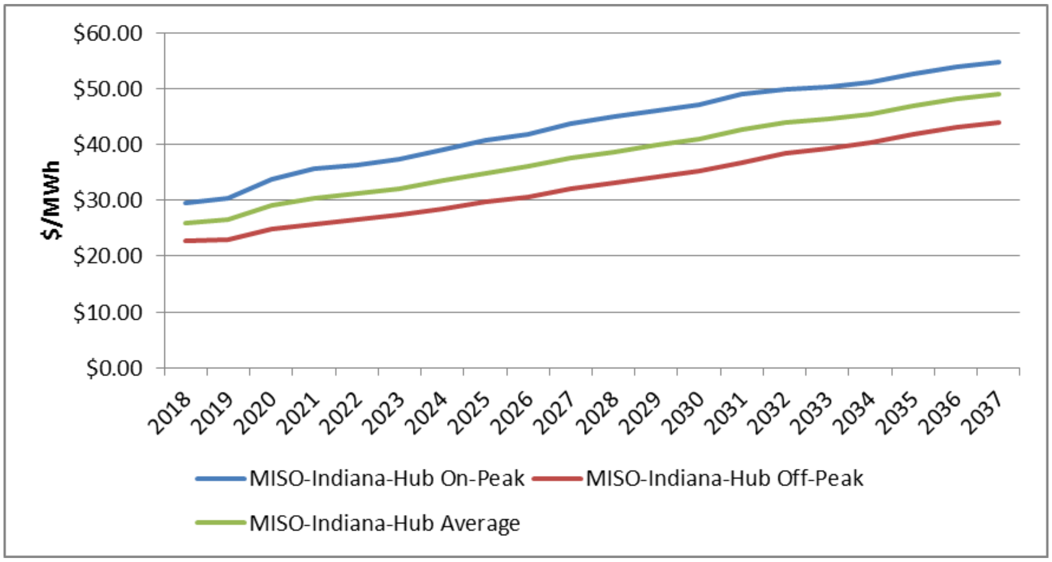
Particulate emissions generally remain stable over the study as well, save mercury emissions which are expected to decline in the later years of the study as older coal units are retired and replaced with natural gas fired generation.

Figure 80 High Growth Case MISO Particulate Emissions



Because the High Growth Case has no carbon tax applied, the main driver for pricing is ultimately load growth, which is assumed to be higher than either the Base or Green Cases. Prices at Indiana Hub are expected to gradually escalate over time but average around $30/MWh over the next 10 years.

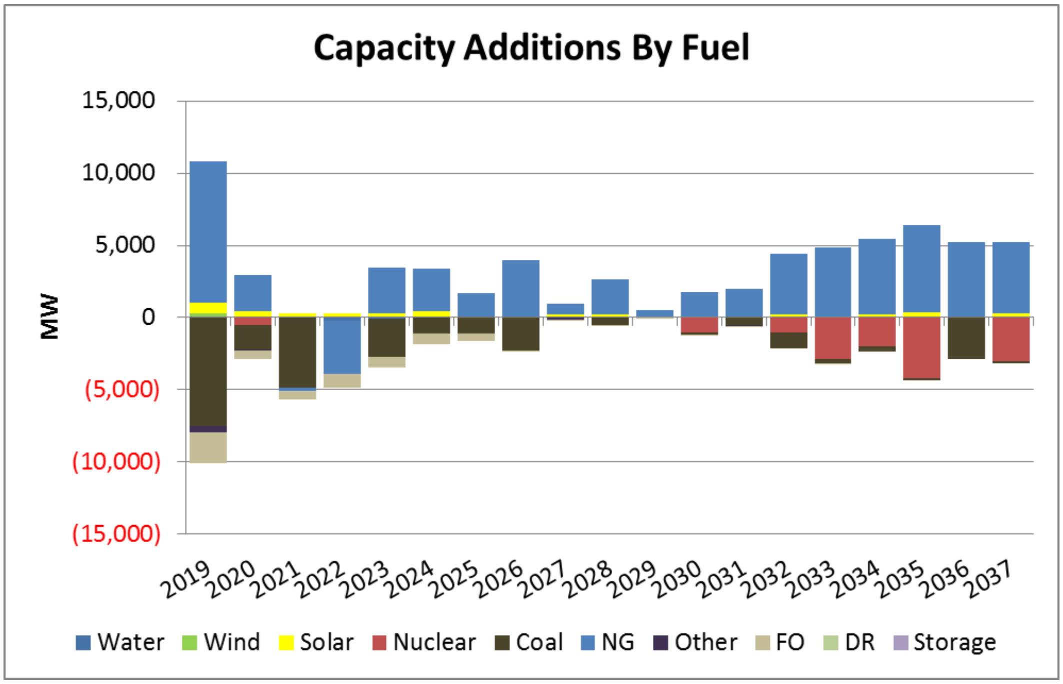
Figure 81 High Growth Case Indiana Hub Prices



12.5.2 PJM Expansion Results

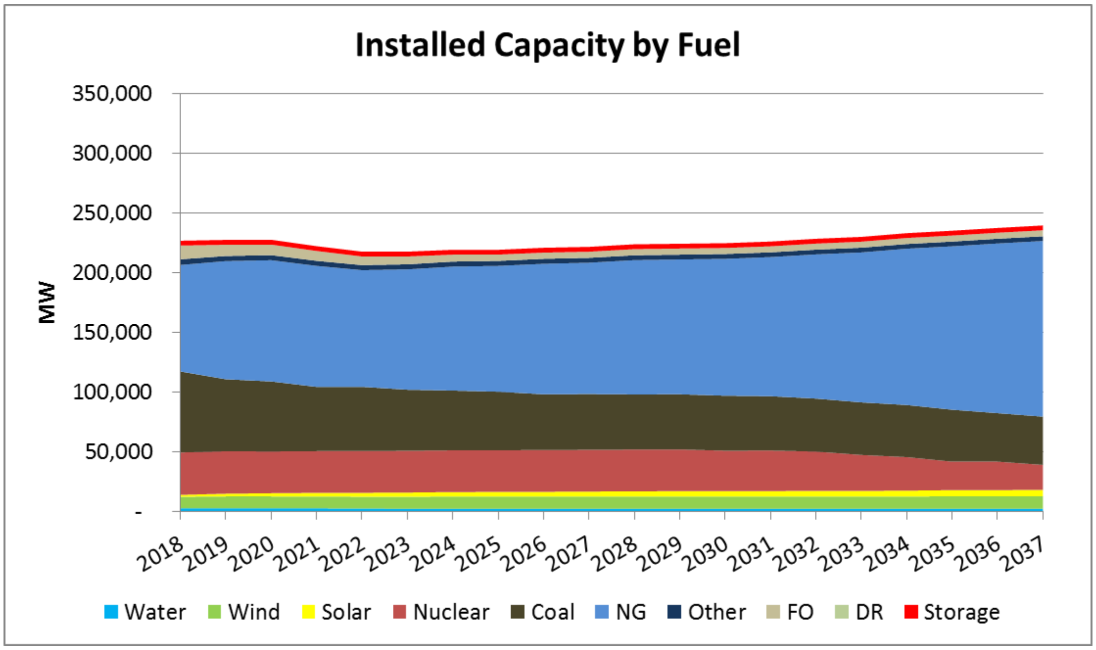
In PJM, capacity additions are expected to be muted for most of the study period. The early years see a reshuffling of the stack, with about 7,500 MW of coal retirements offset by 9,800 MW of natural gas generation.

Figure 82 PJM High Growth Case Net Capacity Additions by Fuel



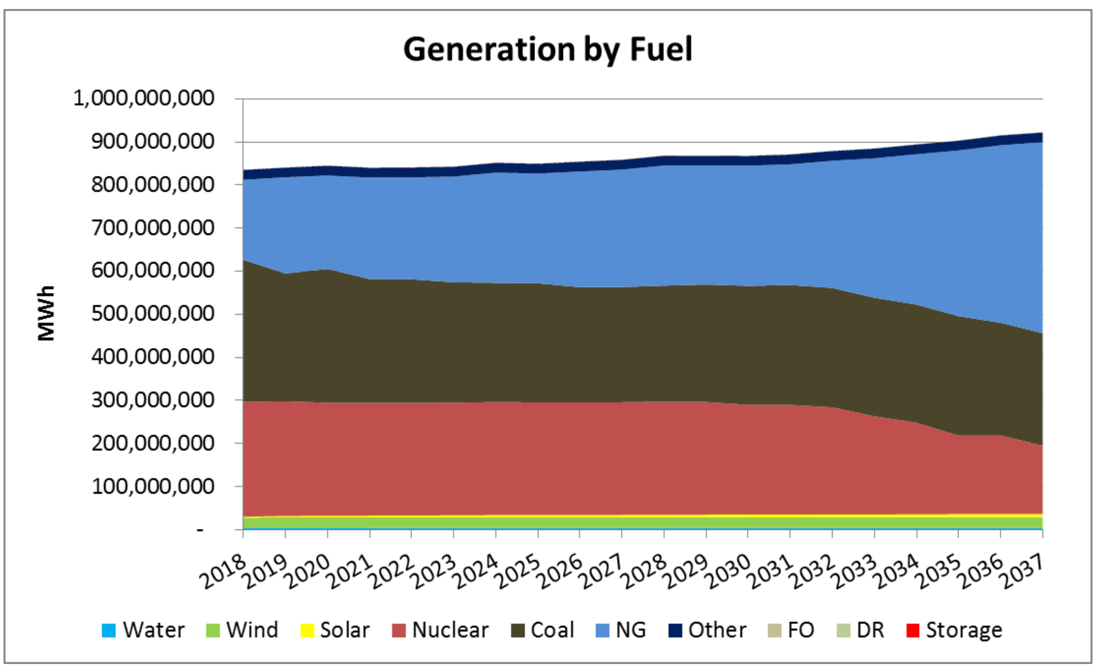
Under the High Growth Case, coal's decline in PJM is much more gradual than either of the two scenarios, but comparable to the declines seen in MISO.

Figure 83 High Growth Case PJM Total Installed Capacity



On a total generation basis, natural gas very gradually supplants coal and nuclear generation over time as older units are retired and replaced with economically more competitive combined cycles and peaking combustion turbines.

Figure 84 High Growth Case PJM Generation by Fuel



Whereas MISO saw no initial reduction in CO_2, the initial retirement of coal in PJM seen above leads to decline in gross CO_2 emissions. CO_2 emissions stabilize over the intermediate time period before climbing again in the late 2020s. This is ultimately being driven by load growth induced generation expansion.

Figure 85 High Growth Case PJM CO_2 Emissions

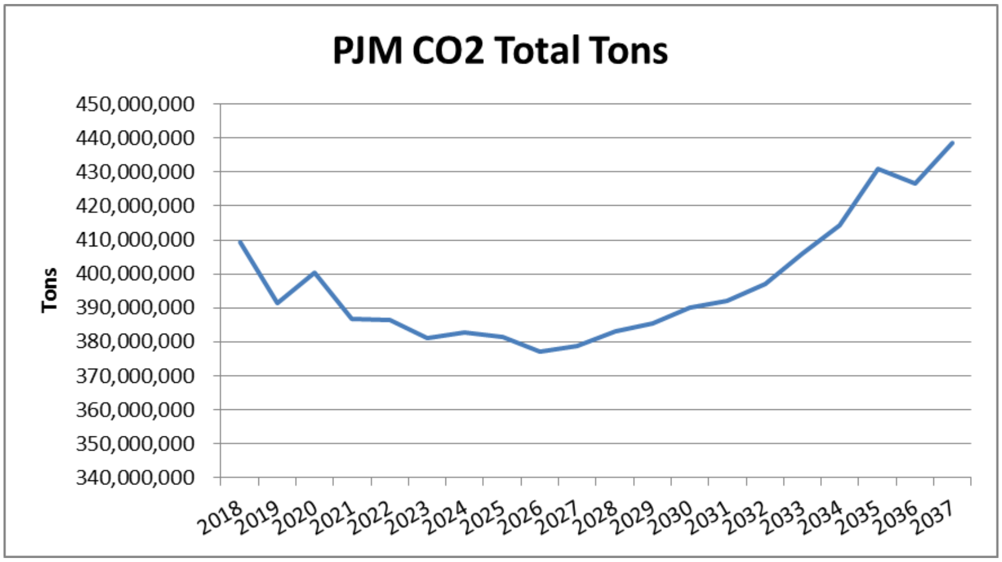
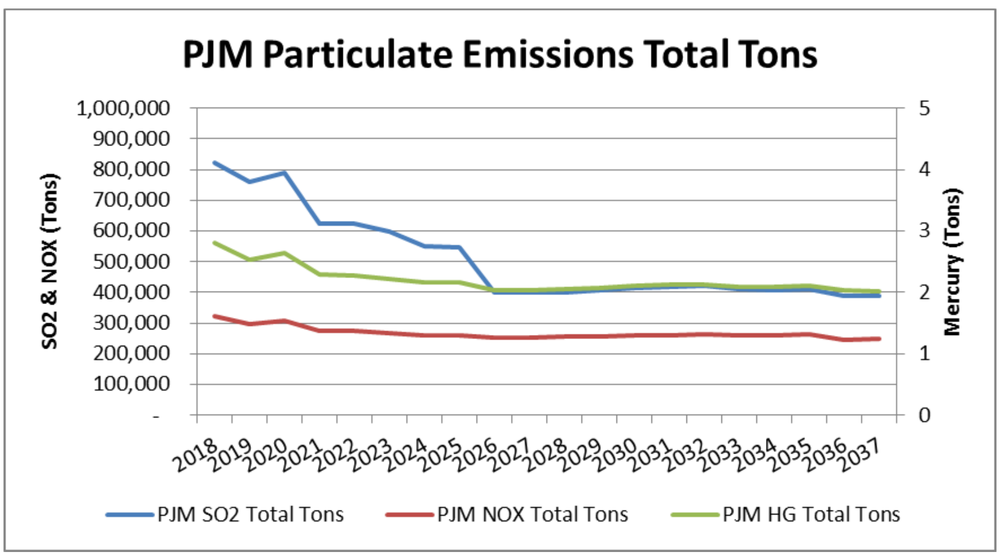


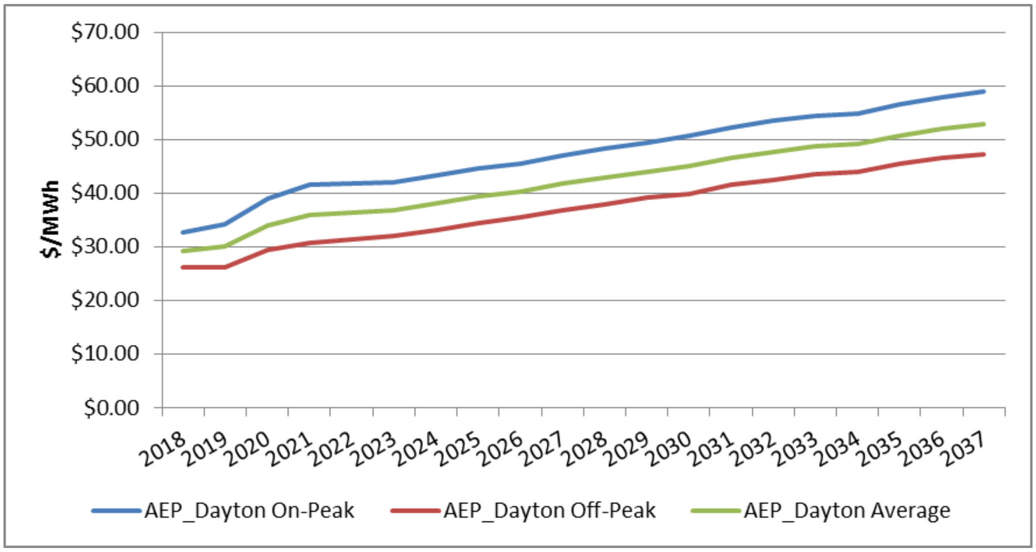
Figure 86 High Growth Case PJM Particulate Emissions



PJM particulate emissions follow a similar trend as MISO under the High Growth Case assumptions with coal centric particulates gradually being reduced over time as coal units are retired, while NO_x stays somewhat stable given the increased reliance on natural gas generation.

Similar price trends are seen in PJM as in MISO, albeit at higher overall levels due to higher expected demand and slightly different resource mix.

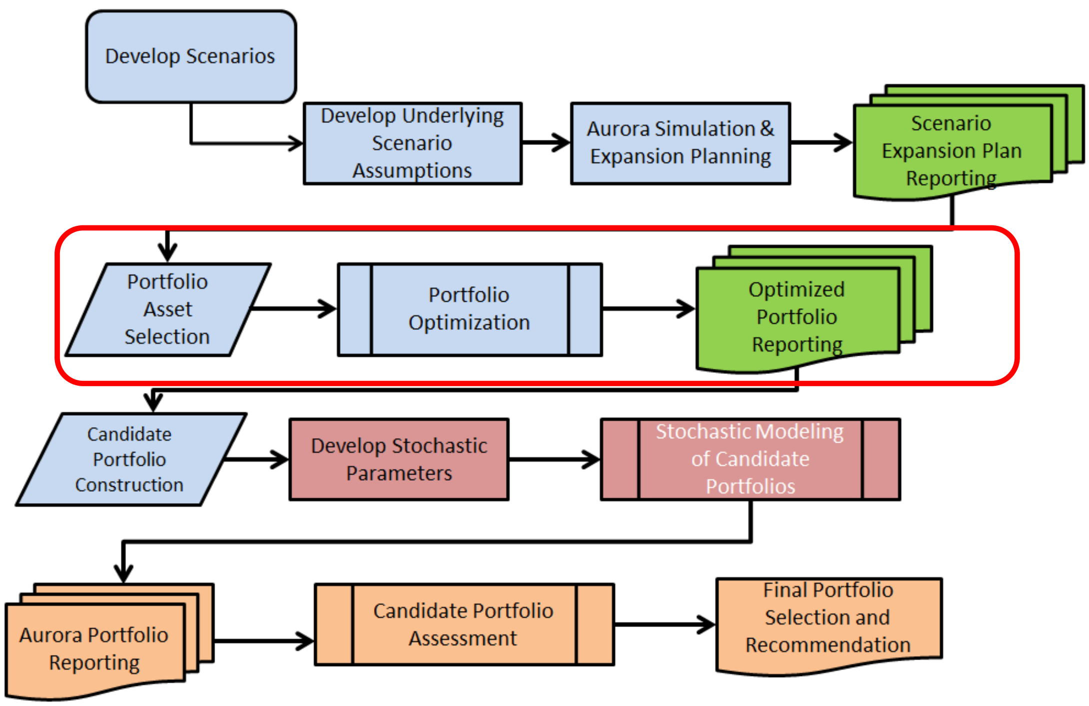
Figure 87 High Growth Case AD Hub Prices



13 PORTFOLIO OPTIMIZATION

Once scenarios have been designed and Aurora has created a zonal expansion plan that is optimal for that set of assumptions, IMPA selects groups of existing and yet-to-be built assets for portfolio consideration. The asset selection for the IMPA portfolio is dependent on the output of the Aurora zonal expansion module under the assumption that whatever is most efficient for the RTO should provide IMPA a set of diverse and rational asset choices for its own portfolio. In other words, if a resource is not built in the RTO expansion study, it cannot be considered for IMPA's portfolio (unless that resource is already an existing resource). Aurora then optimizes the selection of assets such that the portfolio cost is minimized over time while honoring reserve margin and other constraints. Ultimately, each scenario yields an optimal IMPA portfolio for that given scenario.

Figure 88 IRP Flowchart – Portfolio Optimization



Eligible assets for portfolio optimization are ultimately sourced from existing and newly "constructed" assets from the relevant scenario output discussed in the previous section. Therefore, the overall framework is that the most efficient zonal expansion drives asset selection for the most efficient portfolio.

Once the Long Term Optimizations were run under each set of scenario assumptions (as more fully detailed in section 12), IMPA was then free to utilize AuroraXMP's portfolio optimization tool. This tool allows users to assemble a list of candidate assets, either pre-existing or those built by the model in the zonal expansion, for consideration in the portfolio. The optimization selects asset type and quantity subject to minimizing cost while meeting reserve margins and other constraints. These additions reflect utility scale additions to IMPA's portfolio and do not reflect IMPA's ongoing commitment to expanding its solar projects, which is included in all three plans.

Table 15 Expansion Results – 3 Plans

Case Comparison and MW Additions/Subtractions by Year			
Drivers	*Base Case*	*Green Case*	*Robust Growth/De-regulation*
Economic Growth	2.1%	1.5%	2.6%
Capital Costs	Reference	Reference	Reference
Load Forecast	IMPA Base Case	IMPA Reference -3.3%	IMPA Reference +3.2%
Natural Gas Prices	Reference	Base +35% (on average)	Reference +32%
Coal Price	Reference	Reference +2%	Reference +6%
CO2 Policy	$20/Ton in 2026	$40/Ton in 2026	None
RPS	No	20% by 2030 w Phase In	No
Reserve Margin	Reference Area	Reference Area	Reference Area
2018	+100 Bi-Lateral Capacity	+100 Bi-Lateral Capacity	+100 Bi-Lateral Capacity
2019	+50 Wind	+50 Wind	+10 Bi-Lateral Capacity
2020			
2021	+100 Bi-Lateral Capacity	+100 Bi-Lateral Capacity	+100 Bi-Lateral Capacity
2022			
2023			
2024		+60 CC/+50 Wind/TC1 Retires (-66)	
2025		+55Wind	
2026	+200 CC/+50 Wind/WWVS Retires (-100)	WWVS Retires (-100)/+150 CC/+150 Wind/+35 Solar	+200 CT
2027		Gibson 5 Retires (-156)/+100 CC/+100 Solar	
2028			
2029		+40 Wind	
2030		+40 Wind	
2031			
2032		Rensselaer 15 Retires (-8)	
2033			
2034	+264 MW CC/-195 AEP Contract	+120 CC/-195 AEP Contract	+120 CT/-195 AEP Contract
2035		+70 Solar/+100 Wind	+90 CT
2036		TC 2 Retires (-95), +100 CC, +85 Wind	
2037			

In all three plans, it is notable that the first five to seven years, the most optimal solution is to utilize market products for incremental capacity needs as these represent the most economic means to satisfy planning requirements. Within the same time period, only the High Growth Case shows no additional renewable capacity additions (other than IMPA's existing and planned commitment to solar generation for its member communities). With markets for capacity being less visible beyond 2025, all three cases are in agreement that some installed generating capacity is needed by 2026 with quantities varying depending on the retirement picture.

In both the Base Case and the Green Case, carbon taxation and, in the case of the Green Case, a Federal RPS, retirement of some IMPA resources occurs. This capacity is replaced with a combination of combined cycle and renewable generation in both the Green Case and the Base Case, while the High Growth Case merely replaces lost capacity with inexpensive peaking generation. With the Green Case representing a relatively aggressive policy shift, the earliest IMPA would need to begin to pivot its portfolio would be 2024, stemming from the modeled retirement of Trimble County 1. This also reflects a need to rebalance towards the Federal RPS assumed in the Green Case.

Post 2026, the Base Case and the High Growth Case are similar in that there are no retirements or capacity needs until 2034. In contrast, the Green Case sees additional retirements and an increased need to replace lost generation with a combination of natural gas and renewable generation.

In summary, all three cases see IMPA adding approximately 200 MW of market capacity in the next five to seven years while two of the three cases see wind as a prudent short term decision.

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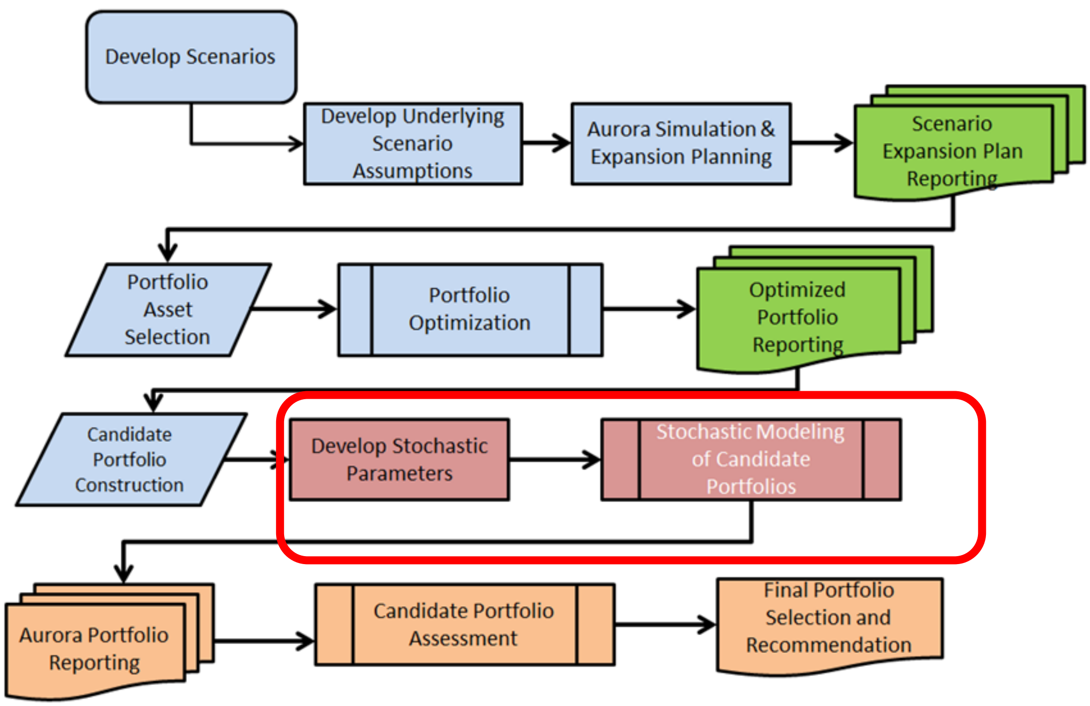
14 STOCHASTIC PROCESS

AuroraXMP contains an integrated risk model as part of its suite of capabilities. Parameters such as volatility and cross commodity correlation are developed and entered into AuroraXMP's risk framework. Using this risk model, each candidate portfolio can be evaluated for robustness given uncertain outcomes. These runs were performed under the same underlying assumptions as the deterministic assumptions set forth in sections 12 and 13. The main difference between the stochastic and deterministic runs, however, is the introduction of uncertainty and risk to the process. While the deterministic and stochastic runs share approximately the same mean, or expected outcome, comparison of results between the deterministic and stochastic cases can be problematic due to stochastic runs capturing extremes across a distribution of outcomes. In other words, the stochastic runs contain probabilistic information not included in the deterministic runs done previously. As such, despite sharing the same expected outcome, the cases are inherently different. That said, the stochastic runs in the following discussion are valuable as a means to assess the risk in each portfolio constructed.

Figure 89 IRP Flowchart – Stochastic Process



14.1 AuroraXMP - Stochastic Inputs

In order for these parameters to be modeled within AuroraXMP, IMPA was tasked with estimating both volatility and correlations across fuels and system demand as AuroraXMP ultimately models the entire Eastern Interconnect under uncertainty with the parameters it is given. As such the main risk variables modeled were:

- Natural Gas (at Henry Hub)
- Coal (at a variety of delivery locations)
- MISO Load
- PJM Load
- Emissions
- Generation Availability

In order to estimate correlation, daily historical data was first gathered for these variables starting in 2006 and ending in mid-2017. Daily correlations throughout the range of obtainable data yielded the following correlations.

Table 16 Historical Daily Correlations

Daily Correlations 2006- June 2017				
	Midcontinent ISO Load	*PJM Load*	*HH Gas*	*Smoothed Coal*
Midcontinent ISO Load	1.00			
PJM Load	0.74	1.00		
HH Gas	-0.04	-0.12	1.00	
Smoothed Coal	-0.20	-0.04	0.35	1.00

Using this data however includes a number of outliers. In addition, while AuroraXMP can handle daily correlations, it significantly increases the computational burden on the software. With the initial period of data including an active Atlantic hurricane season in 2008 in addition to a prolonged economic recession in the following years, IMPA opted to select monthly correlations from 2012 on as the basis for more normalized correlations. These are show in the table below.

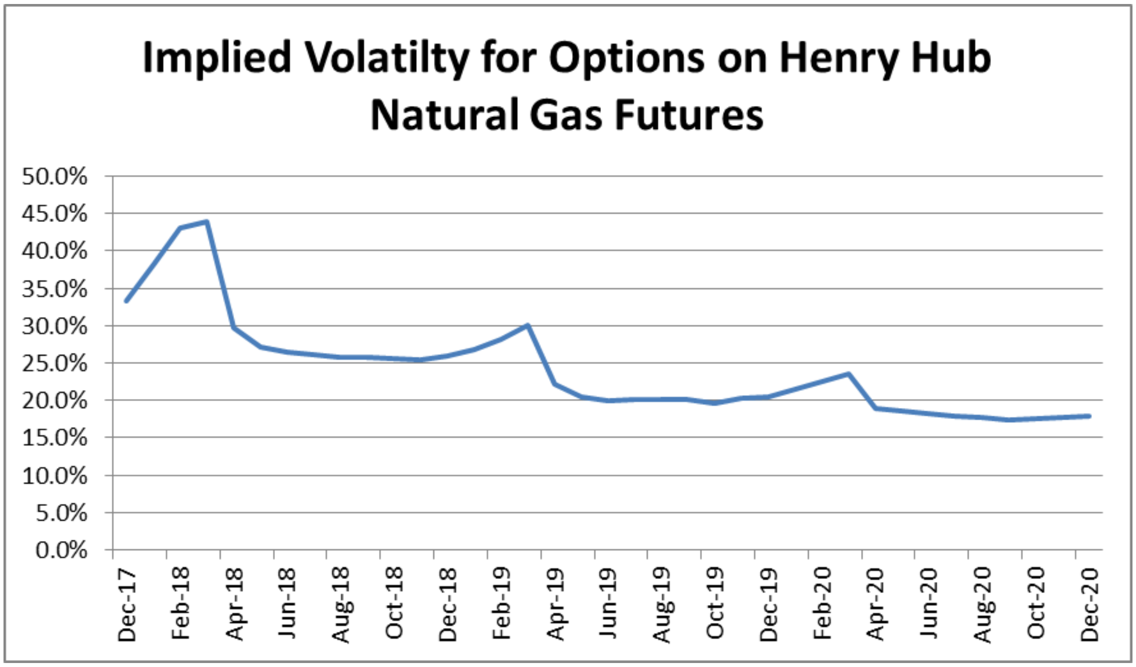
Table 17 Historical Monthly Correlations

Monthly Correlations 2012-Present				
	Midcontinent ISO Load	*PJM Load*	*HH Gas*	*Smoothed Coal*
Midcontinent ISO Load	1.00			
PJM Load	0.61	1.00		
HH Gas	0.07	0.15	1.00	
Smoothed Coal	-0.51	0.05	0.50	1.00

The second parameter to estimate for the stochastic portion was volatility of each risk variable. IMPA prefers using market based indicators as much as possible in order to have some unbiased estimate of market volatility. For Henry Hub natural gas, implied volatility from options on natural gas futures were used for this estimate. Implied volatility was calculated from observed options prices quoted on the CME Group website.[21]

[21] http://www.cmegroup.com/trading/energy/natural-gas/natural-gas.html

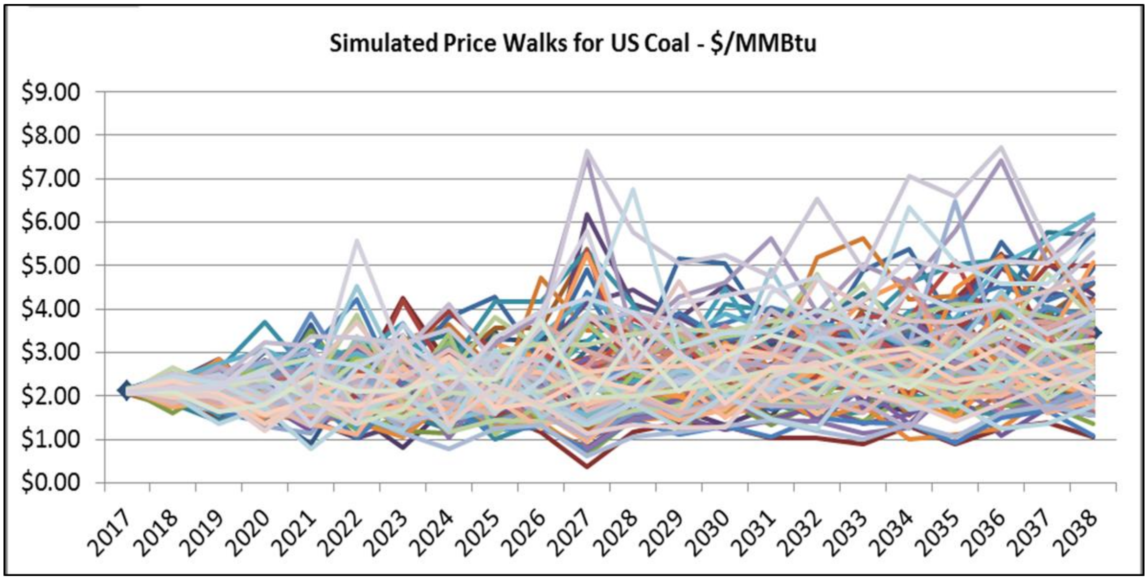
Figure 90 Term Structure for Options on Natural Gas Futures



For volatility parameters on variables with no liquid market (i.e., system loads, coal), historical data was used.

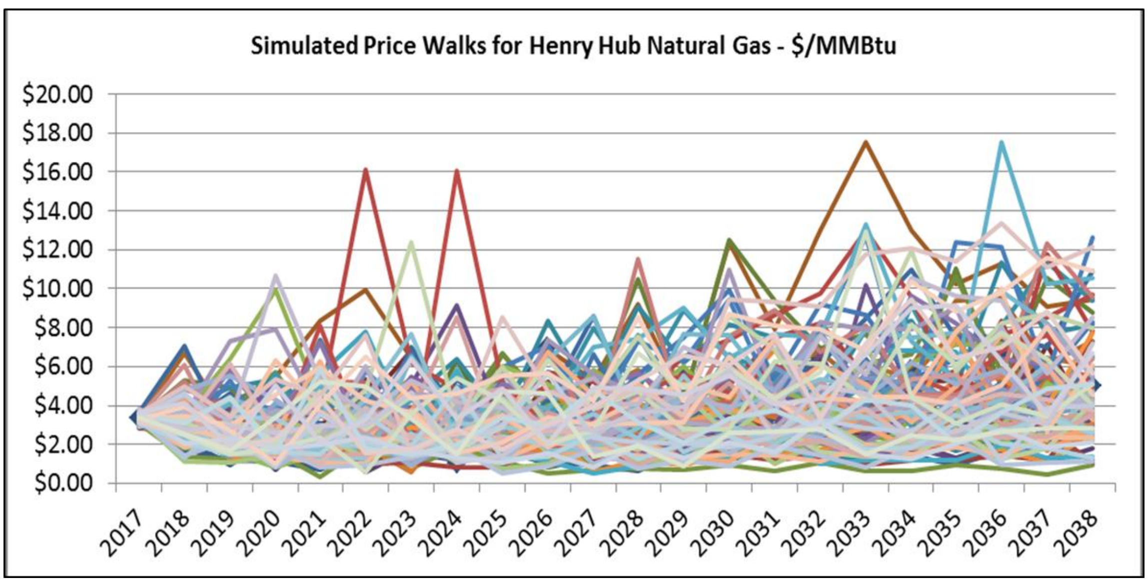
These parameters were entered into the AuroraXMP's risk module and 100 iterations of each variable were simulated. The following figures illustrate the simulated "walks" of the most crucial risk variables under the Base Case. Similar walks were created for the Green and High Growth Cases.

Figure 91 Simulated Price Walks, US Coal, Base Case



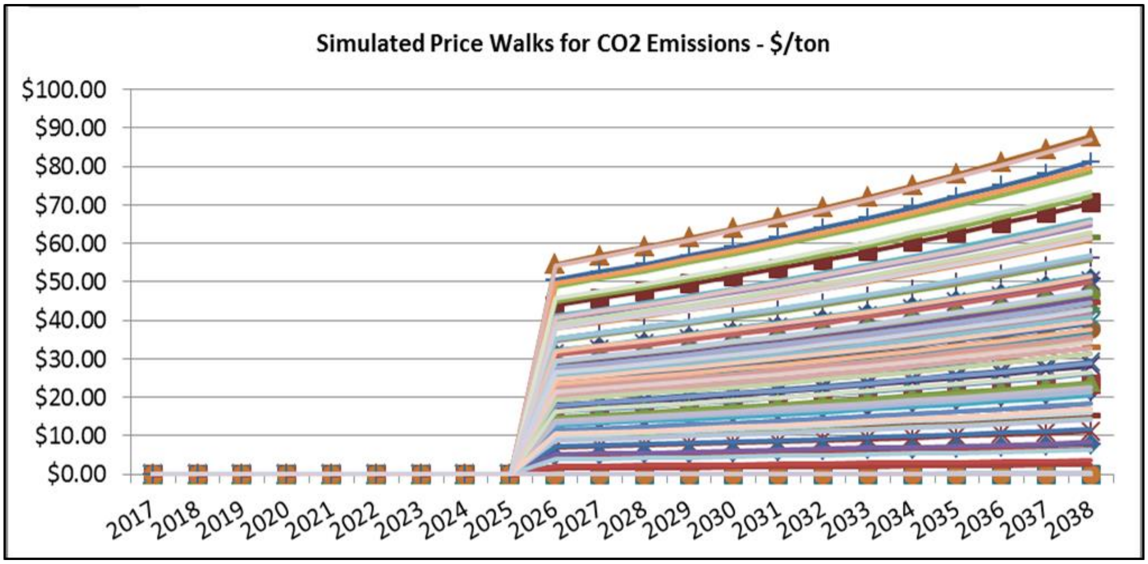
IMPA's use of market implied volatility for natural gas captures the dynamic of increasing uncertainty the further one looks into the future. Once market implied volatility is no longer available, IMPA transitions volatility to a gradually declining term structure.

Figure 92 Simulated Price Walks, Henry Hub Natural Gas, Base Case



For carbon tax uncertainty, IMPA's goal was to capture not only the policy risk of what potential policy decisions would be but also the downside implications of constructing a portfolio of resources around an assumed carbon policy, then having that policy not materializing. As such, the figure below illustrates a handful of zero dollar price walks.

Figure 93 Simulated Price Shifts, CO_2, Base Case



Beyond just uncertainty in fuel prices and emissions prices as risks to generators, IMPA has also modeled uncertainty in load parameters, both at the zonal level and at the IMPA level. The figure below is representative of the uncertainty being captured in potential load deviations.

Figure 94 Simulated Walks, IMPA MISO Load, Base Case

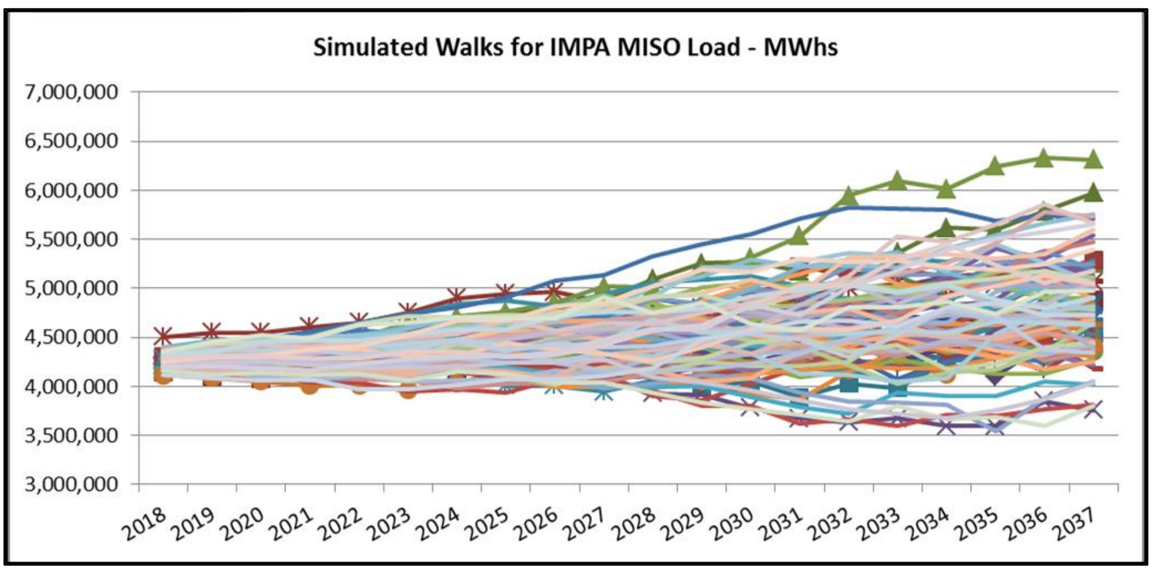
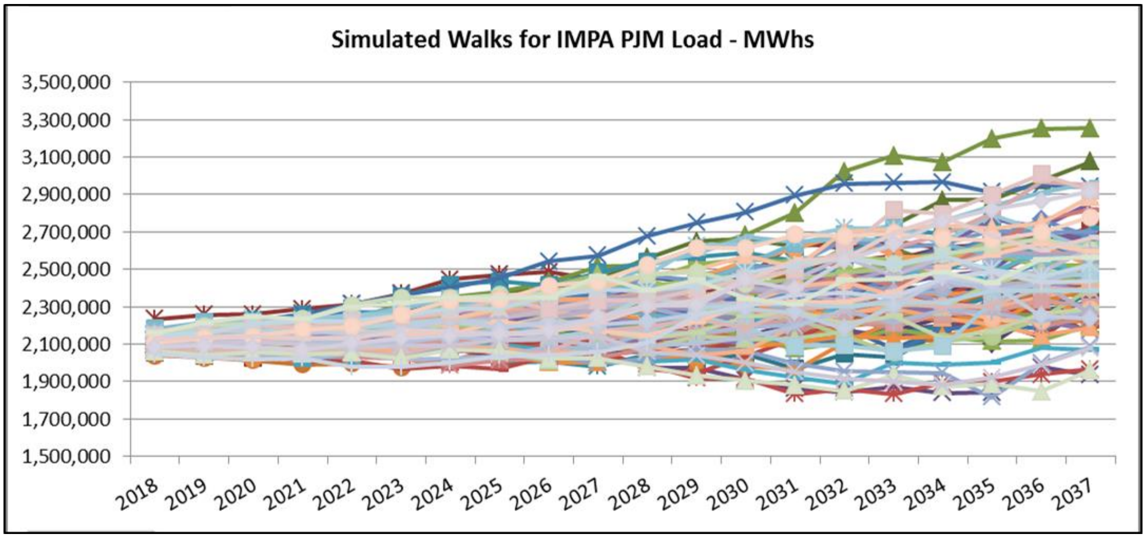


Figure 95 Simulated Walks, IMPA PJM Load, Base Case



14.2 AURORAXMP – STOCHASTIC RESULTS – MARKET PRICES

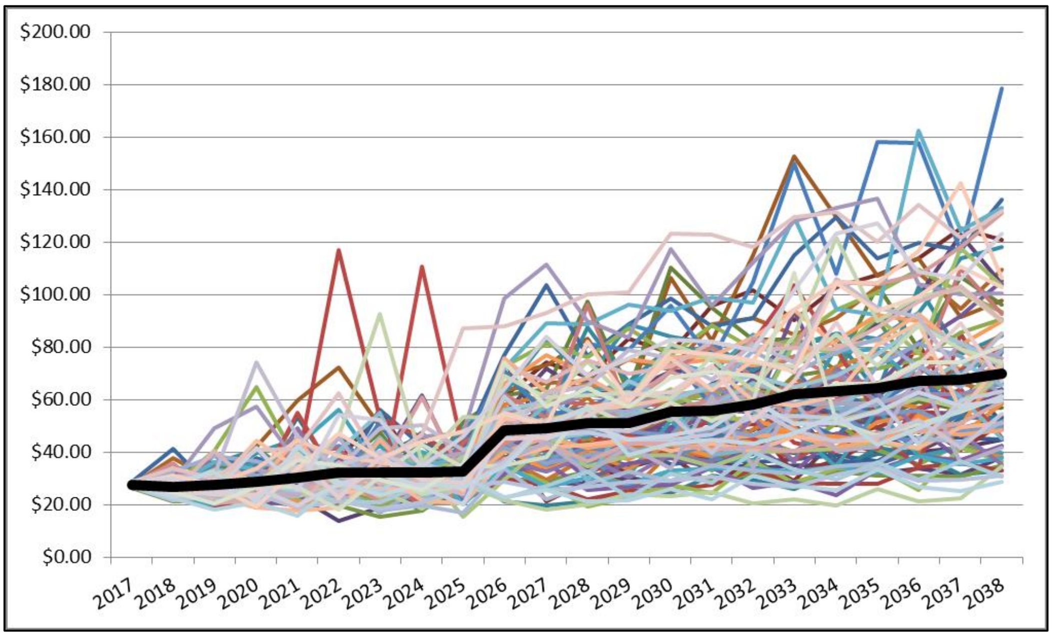
Introduction

The risk parameters discussed in the previous section, among others, are all entered into AuroraXMP's unit commitment and dispatch model, which then dispatches all of the units in the Eastern Interconnect based on the underlying draw for each correlated risk variable. The resulting output is stochastic zonal pricing and portfolio valuation.

14.2.1 Base Case Stochastic Prices

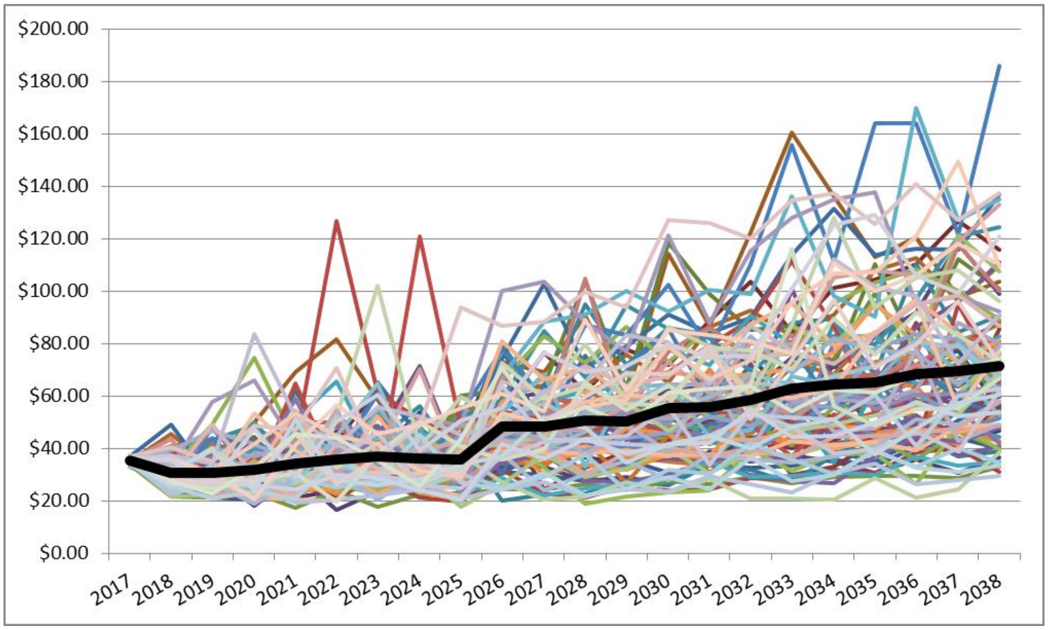
The figure below illustrates the resulting Indiana Hub price under uncertainty with the stochastic mean illustrated with the heavier black line. The step function is a result of the assumed (but not certain) $20/ton CO_2 tax. This volatility, when combined with volatility on loads and fuels, materially impacts the uncertainty on hub pricing beyond 2026.

Figure 96 MISO – Indiana Hub Annual 7x24 Market Prices ($/MWh), Base Case



A similar pattern is seen with PJM AD Hub pricing, albeit at higher overall levels than Indiana Hub due to regional differences in the supply stack and fuel delivery costs.

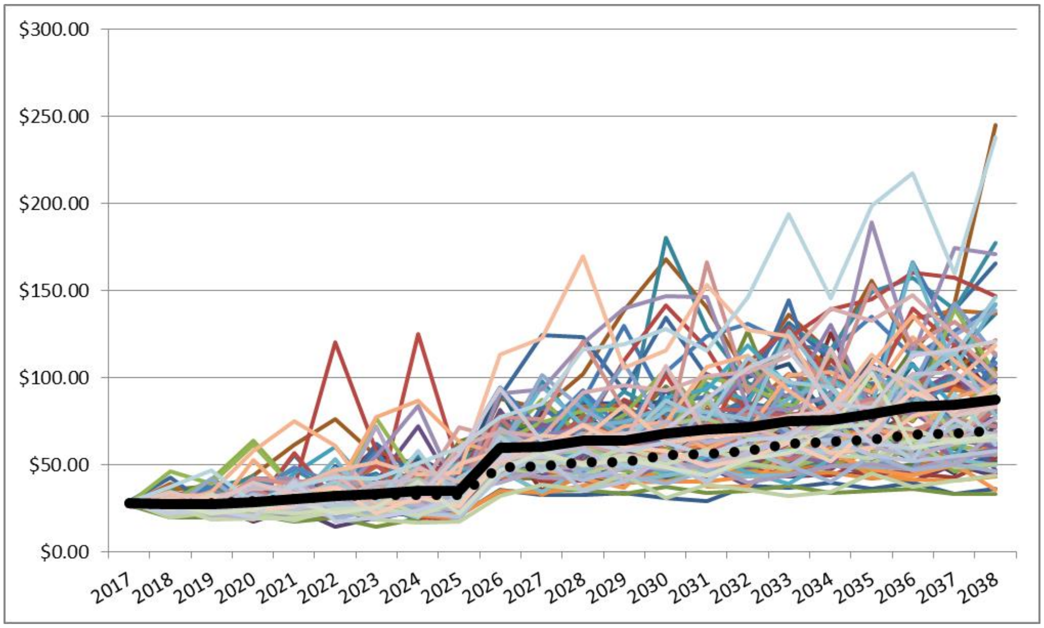
Figure 97 PJM – AD Hub Annual 7x24 Market Prices ($/MWh), Base Case



14.2.2 Green Case Stochastic Prices

The next two figures are of the stochastic hub prices under the assumptions set forth in the Green Case. The dotted black line is the stochastic mean under the Base Case set of assumptions.

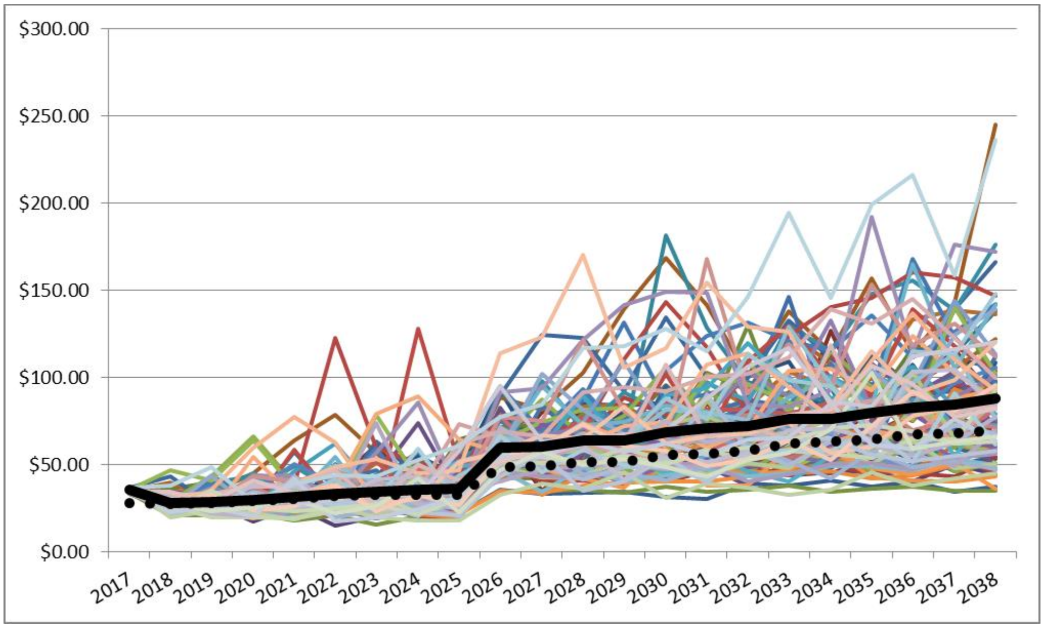
Figure 98 MISO – Indiana Hub Annual 7x24 Market Prices ($/MWh), Green Case



Multiple constraints under the Green Case drive both expectations for future prices higher in addition to exacerbating risk. For example, the ideal build plan is forced to meet a 20% Federal RPS by 2030 in addition to a $40/ton CO_2 tax. Should the stochastic parameters draw a low load iteration and a low carbon iteration, the ideal build plan is now overbuilt/overhedged with respect to environmental risk, driving system cost higher than expected.

Pricing for the AD Hub is shown below, with similar impacts seen in the Base Case.

Figure 99 PJM – AD Hub Annual 7x24 Market Prices ($/MWh), Green Case



As was shown in the Base Case, price differences between AD Hub and Indiana Hub are not terribly dissimilar due to small differences in regional fuel adders and supply stack.

14.2.3 High Growth Case Stochastic Prices

The following figures showing the High Growth Case illustrate lower overall expected market prices and lower expected risk over the study period than either the Base Case or Green Case. This stems largely from the assumption of carbon tax. The black line is the stochastic mean for all iterations for a given year while the dotted line represents the Base Case stochastic mean.

Figure 100 MISO – Indiana Hub Annual 7x24 Market Prices ($/MWh), High Growth

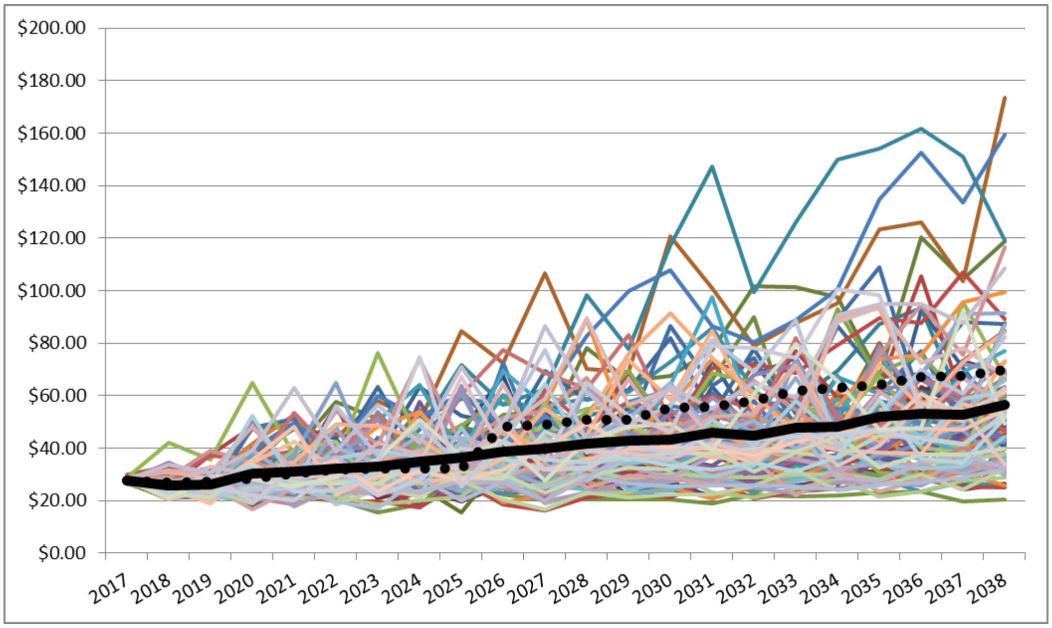
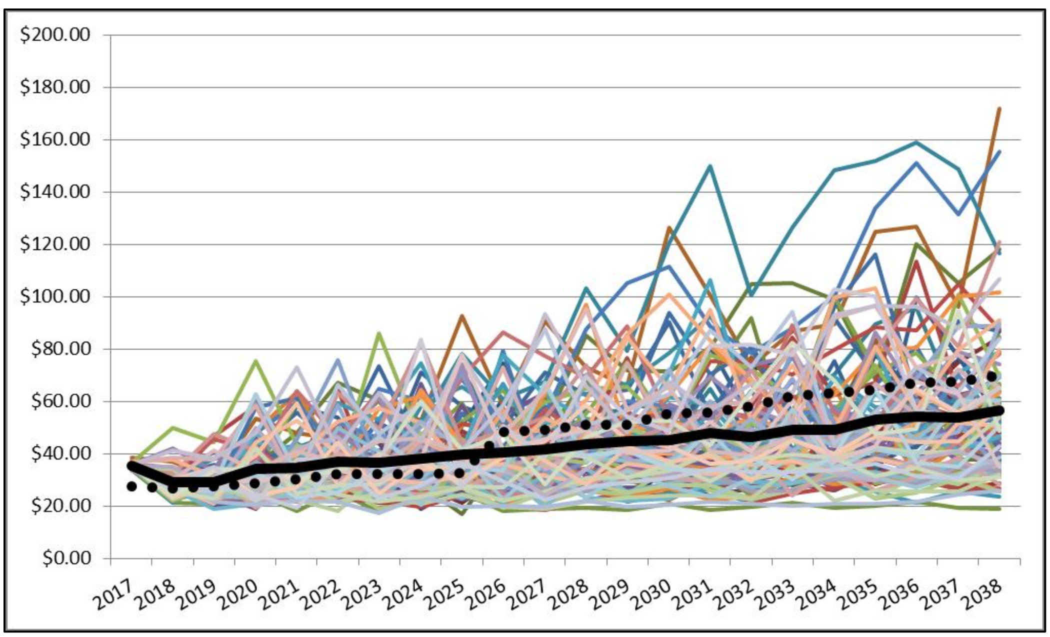


Figure 101 PJM – AD Hub Annual 7x24 Market Prices ($/MWh), High Growth



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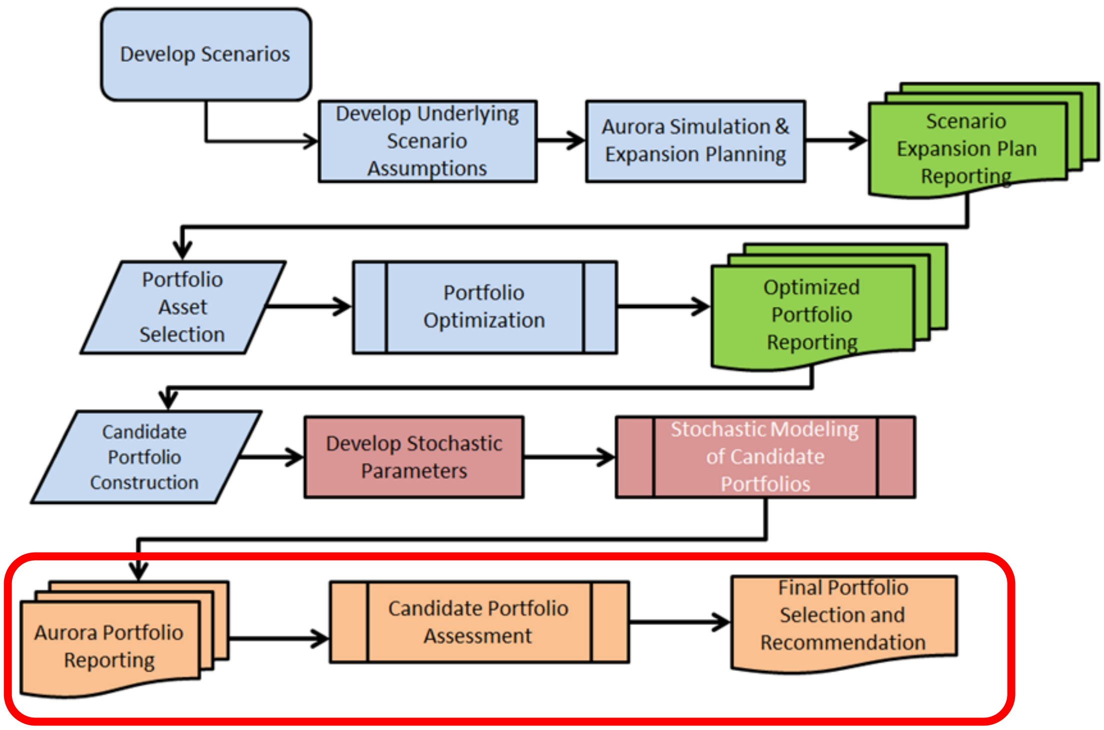
15 PLAN EVALUATION

The final step of the IRP flowchart is detailed analysis of the plans (portfolios) to assess the average system rates, revenue requirements, environmental impacts, and risks associated with each plan. The results and their risk metrics provide IMPA with valuable information regarding the cost and robustness of each plan.

Figure 102 IRP Flowchart – Plan Evaluation



15.1 PLAN EVALUATION METHODOLOGY

As a brief recap, the process to this point has been:

- Develop Scenarios (Base Case, Green Case, High Growth Case)
- Utilize AuroraXMP software to develop 20 year generation expansion plan for Eastern Interconnect
- Utilize AuroraXMP to optimize the IMPA portfolio using available market products and assets developed under the expansion plans
- Once the optimal portfolio is established, model both the Eastern Interconnect and IMPA portfolios under uncertainty using the stochastic module of AuroraXMP.

Risk Profiles Explained

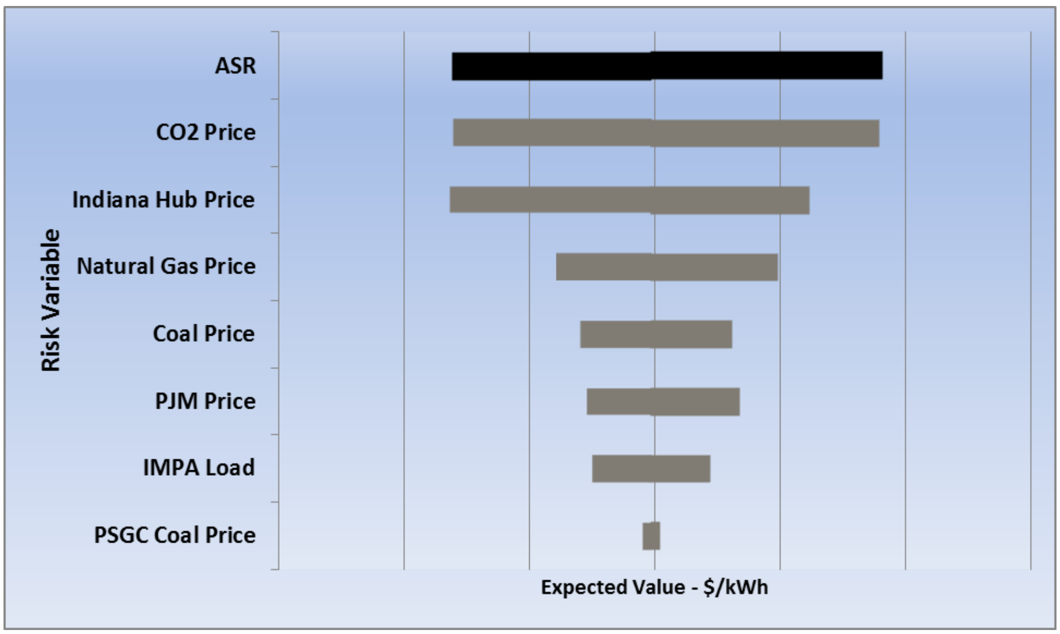
Risk can be shown a variety of ways, with graphs illustrating cumulative probabilities (S curves) common. However, risk is time variant. That is, the longer the event horizon, the greater the uncertainty (and resulting economic risk). The use of cumulative probability to illustrate risk gives equal weight to these more distant and frequently hard to hedge risks. IMPA favors mapping iterative outcomes in average system cost across time and layering risk thresholds over these iterations. IMPA then examines risk at a 90% confidence interval, charting the 5^{th} and 95^{th} percentile outcomes and comparing them across cases. Illustrating risks in this manner allows the viewer to immediately discount more distant risks (e.g., carbon), and compare to a benchmark portfolio (e.g., market prices).

Tornado Charts

To understand the risk of the drivers, IMPA creates tornado charts to determine the sensitivity of the various fundamental drivers on average system rates (ASR). As shown in the figure below, ASR (black bar) is the dependent variable and the remaining drivers are independent variables (gray bars).

The length of the black bar is the uncertainty range of ASR for a selected time frame. The lengths of the gray bars illustrate each independent variable's impact on ASR; the longer the bar, the greater the impact. The expected value is signified by the vertical line. When a gray bar is off-set to the left that means that independent variable puts downward pressure on ASR (good outcome). Conversely, if the gray bar is off-set to the right, then the independent variable puts upward pressure on ASR (bad outcome).

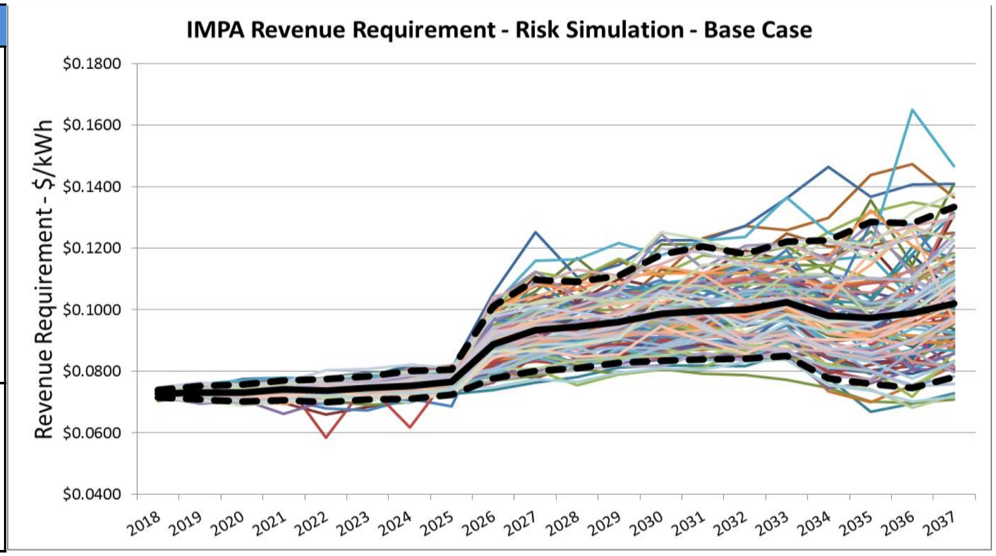
Figure 103 Tornado Chart Example



15.2 BASE CASE RESULTS

Plan Summary: In this optimization, Whitewater Valley Station (WWVS) is retired in 2026 (100 MW) and new combined cycle units are added in 2026 (200 MW) and 2034 (264 MW). In addition to IMPA's current solar expansion plans, the Base Case sees roughly 100MW of utility scale wind being added over two installments in 2019 and 2026. In the near term, IMPA is able to fulfill its capacity obligations via bi-lateral, market based transactions for cheaper than the cost of new generation due to ample reserve margins in MISO.

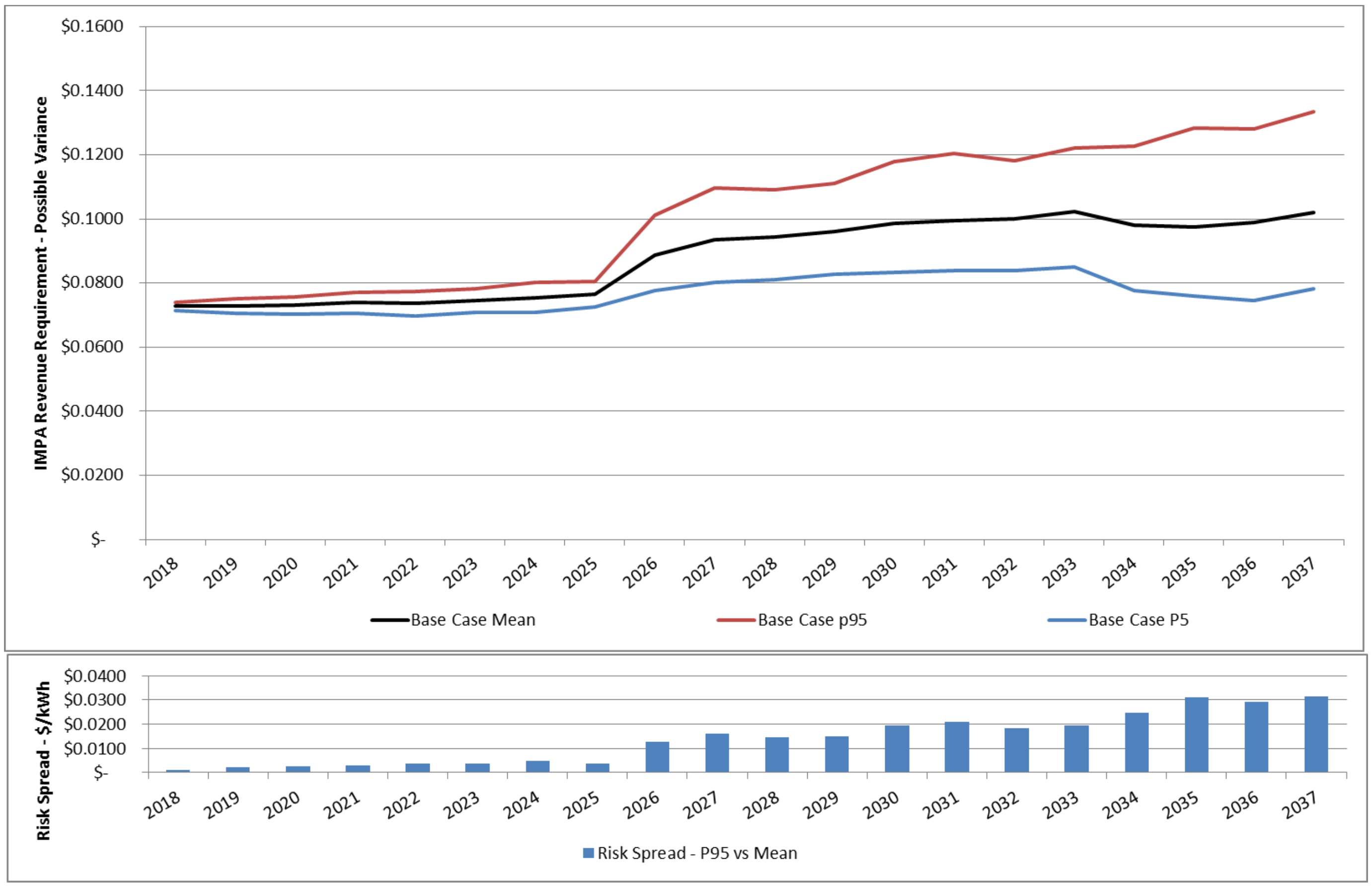
Drivers	Base Case
Economic Growth	2.1%
Capital Costs	Reference
Load Forecast	IMPA Base Case
Natural Gas Prices	Reference
Coal Price	Reference
CO2 Policy	$20/Ton in 2026
RPS	No
Reserve Margin	Reference Area
Retirement MW	-100
Mkt Capacity Transaction MW	200
Natural Gas Additions MW	464
Renewable Additions MW	90



Plan Observations: The least cost solution prior to the 2026 CO_2 tax regime is to continue a low price environment by filling capacity needs with bi-lateral capacity transactions. After 2026, incremental capacity needs are met with less carbon intensive sources of generation such as combined cycle units and wind. In addition, the advent of a carbon tax forces WWVS to retire in 2026.

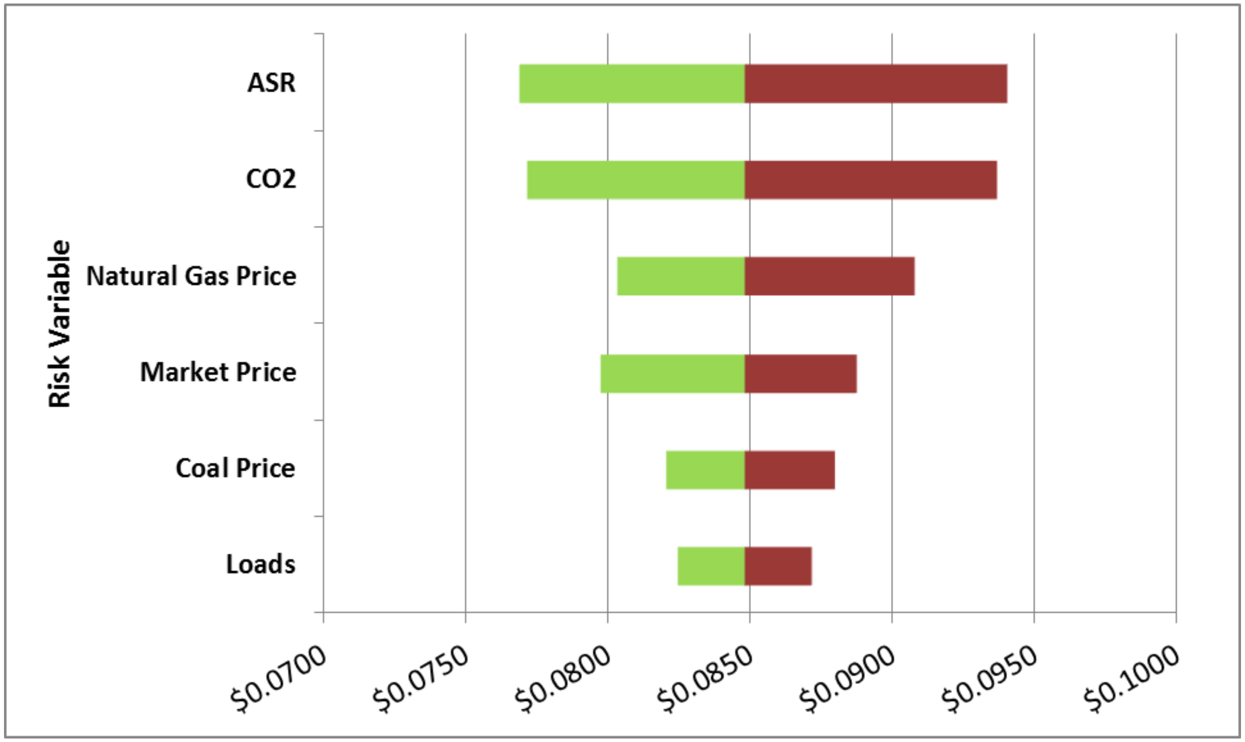
Risk Profile Observations: IMPA's optimal portfolio has a very small risk profile in the early years of the Base Cast study, with a 90% probability that the revenue requirement will be +/- $.003/kWh on an expected revenue requirement of $.074/kWh.

Figure 104 Base Case Risk Profile



Tornado Chart Observations: The following tornado charts summarize the risk over the 20 year study period. Clearly, CO_2 prices represent a considerable portfolio risk to IMPA in this scenario. Apart from CO_2 impacts to risk, fluctuations in natural gas price is a large risk driver in the Base Case as IMPA's portfolio begins to add combined cycle generation. It should be noted that much of this risk stems from the time period beyond 2026 as IMPA is well hedged over the near term (see Figure 15 above).

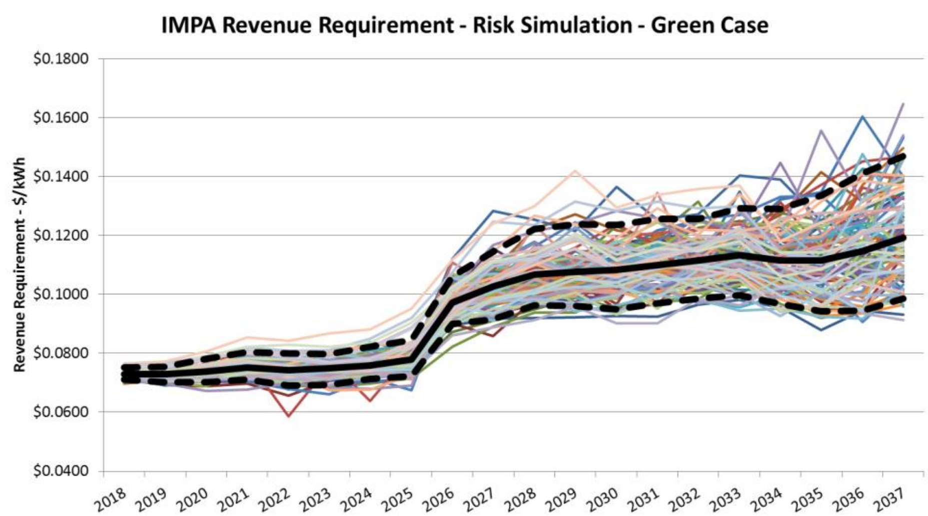
Figure 105 Base Case Tornado Charts



15.3 Green Case Results

Plan Summary: In the Green Case, a $40/ton CO_2 tax materializes in 2026 and a federal RPS standard of 20% of energy sales by 2030 is enforced. Unsurprisingly, this case sees significant coal retirements and aggressive additions of renewables in order to meet and maintain the RPS mandate. Coal capacity is largely replaced with natural gas combined cycles. Note that capacity shown is approximately nameplate ratings. Renewables, for capacity planning purposes, would see a 50% reduction for solar and an 85% reduction for wind from the nameplate number shown here.

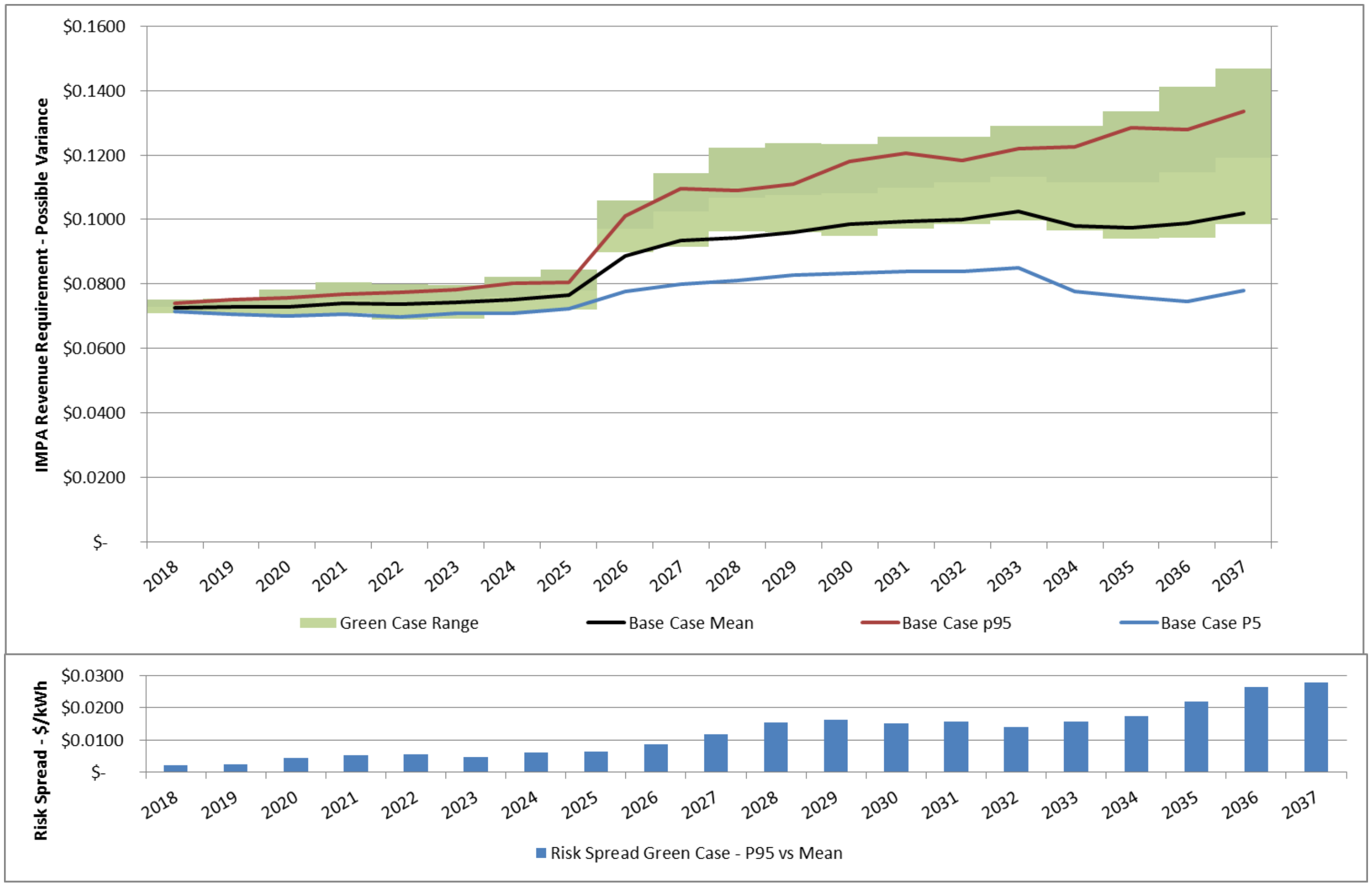
Drivers	Green Case
Economic Growth	1.5%
Capital Costs	Reference
Load Forecast	IMPA Reference -3.3%
Natural Gas Prices	Base +35% (on average)
Coal Price	Reference +2%
CO2 Policy	$40/Ton in 2026
RPS	20% by 2030 w Phase In
Reserve Margin	Reference Area
Retirement MW	-425
Mkt Capacity Transaction MW	200
Natural Gas Additions MW	470
Renewable Additions MW	775



Plan Observations: Despite lower load forecasts, this scenario requires not only the replacement of retired coal generation, but also large renewable capacity additions in order to meet the 20% RPS, over and above IMPAs existing plans for continued development of solar parks.

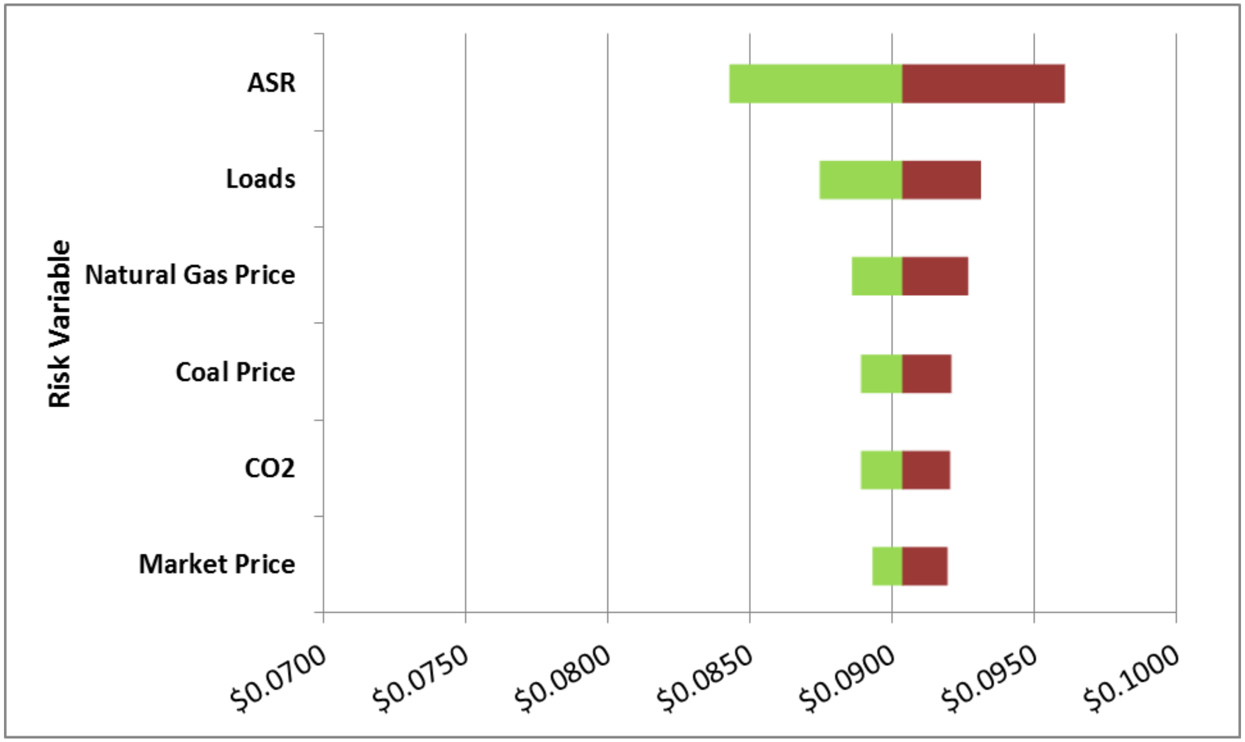
Risk Profile Observations: The Green Case risk profile here is shown overlaid as a green range against the risk profile lines of the Base Case. There is very little deviation between the Green Case portfolio and the Base Case portfolio prior to 2026. However, despite being positioned for a "green world" the portfolio exhibits higher cost while carrying slightly lower risk due to having hedged much of the uncertainty in the portfolio via renewable resources.

Figure 106 Green Case Risk Profile



Tornado Chart Observations: The following tornado chart illustrates selected risk drivers for IMPA's average system rate as modeled in the Green Case. As illustrated, a large risk driver for IMPA in a carbon sensitive regime is the fluctuation in natural gas prices. As reliance on natural gas increases, markets are more sensitive in the delta in cost between the marginal renewable resource and the marginal natural gas resource. As coal is moved further up the resource stack it acts more like an intermediate or peaking resource and its impacts on the risk profile are lower than in the Base Case. Interestingly, as the Green portfolio is optimized for a carbon limited world, impacts from uncertainty in CO_2 price are less impactful than in the Base Case.

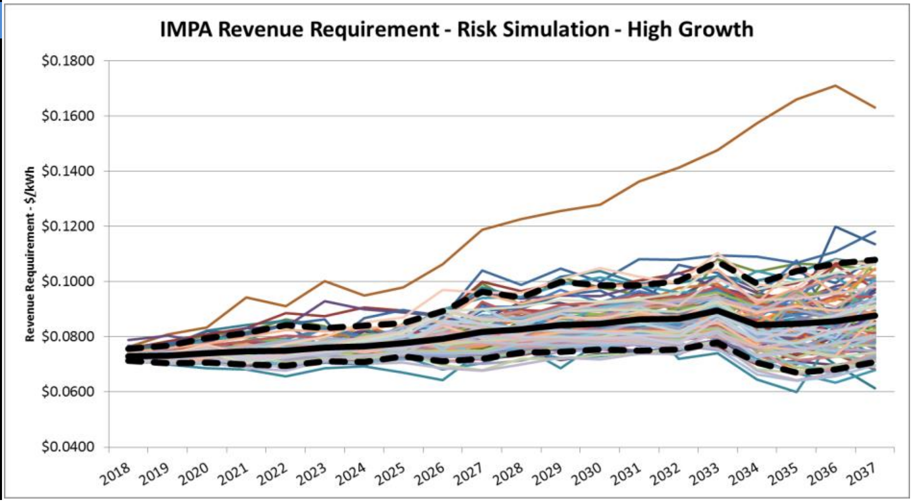
Figure 107 Green Case Tornado Charts



15.4 HIGH GROWTH CASE RESULTS

Plan Summary: The High Growth Case assumes robust economic growth throughout the study timeframe, with growth spurring demand for most commodities across the board, including electricity consumption. In this case, there are no assumptions made regarding CO_2 policy, however the stochastic modeling of CO_2 allowed for a handful of iterations to illustrate a modest carbon tax. Unsurprisingly, there were no IMPA retirements and the only capacity additions were natural gas CTs to meet higher expected peak demand.

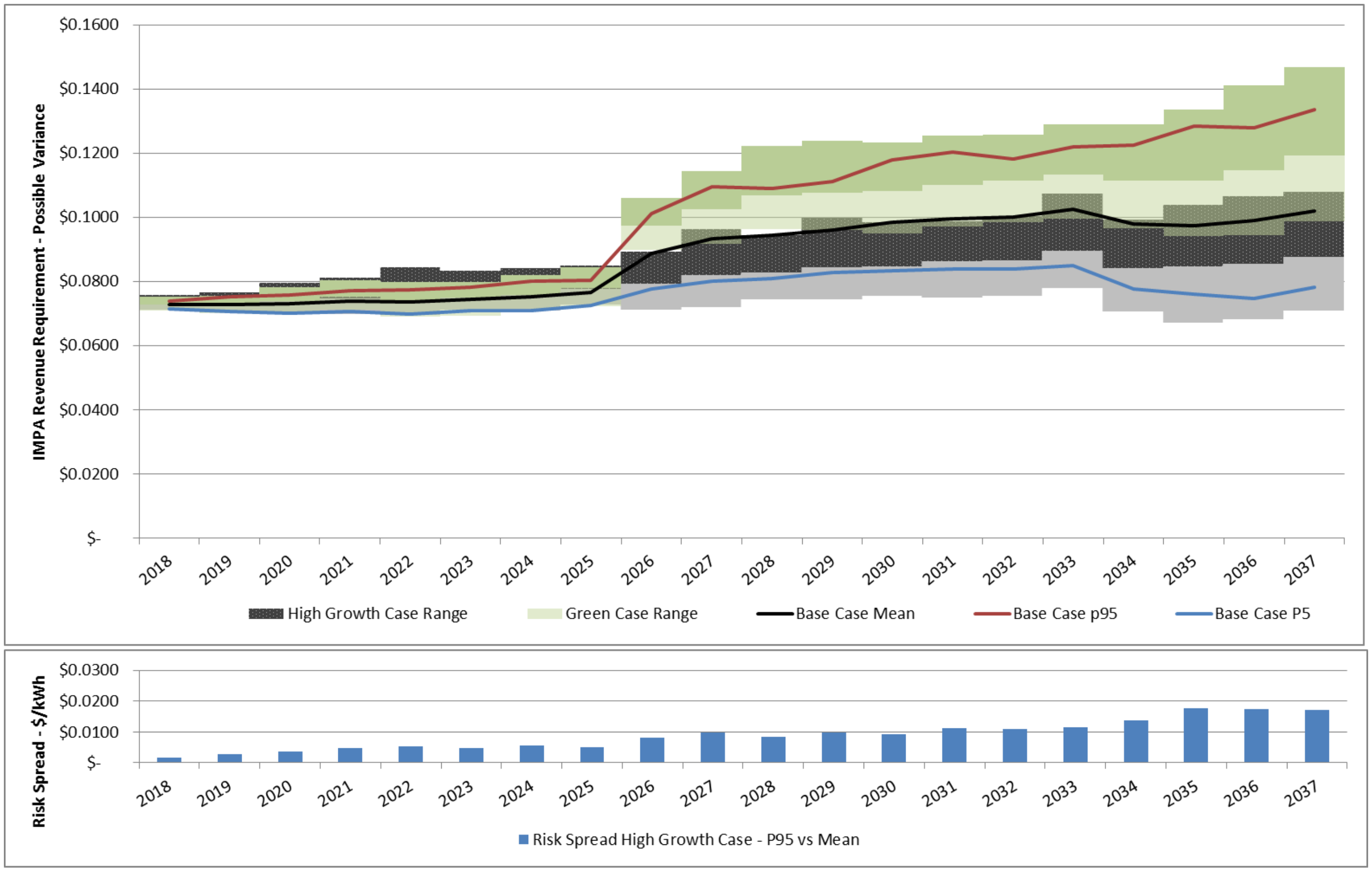
Drivers	*Robust Growth/De-regulation*
Economic Growth	2.6%
Capital Costs	Reference
Load Forecast	IMPA Reference +3.2%
Natural Gas Prices	Reference +32%
Coal Price	Reference +6%
CO2 Policy	None
RPS	No
Reserve Margin	Reference Area
Retirement MW	0
Mkt Capacity Transaction MW	210
Natural Gas Additions MW	410
Renewable Additions MW	0



Plan Observations: This plan and resulting portfolio has the lowest average revenue requirement of all the scenarios with correspondingly higher risk. Absent any sort of environmental regulation or renewable energy incentive, IMPA sees no retirements and capacity needs are met through peaking capacity additions to load growth in 2026, 2034, and 2035.

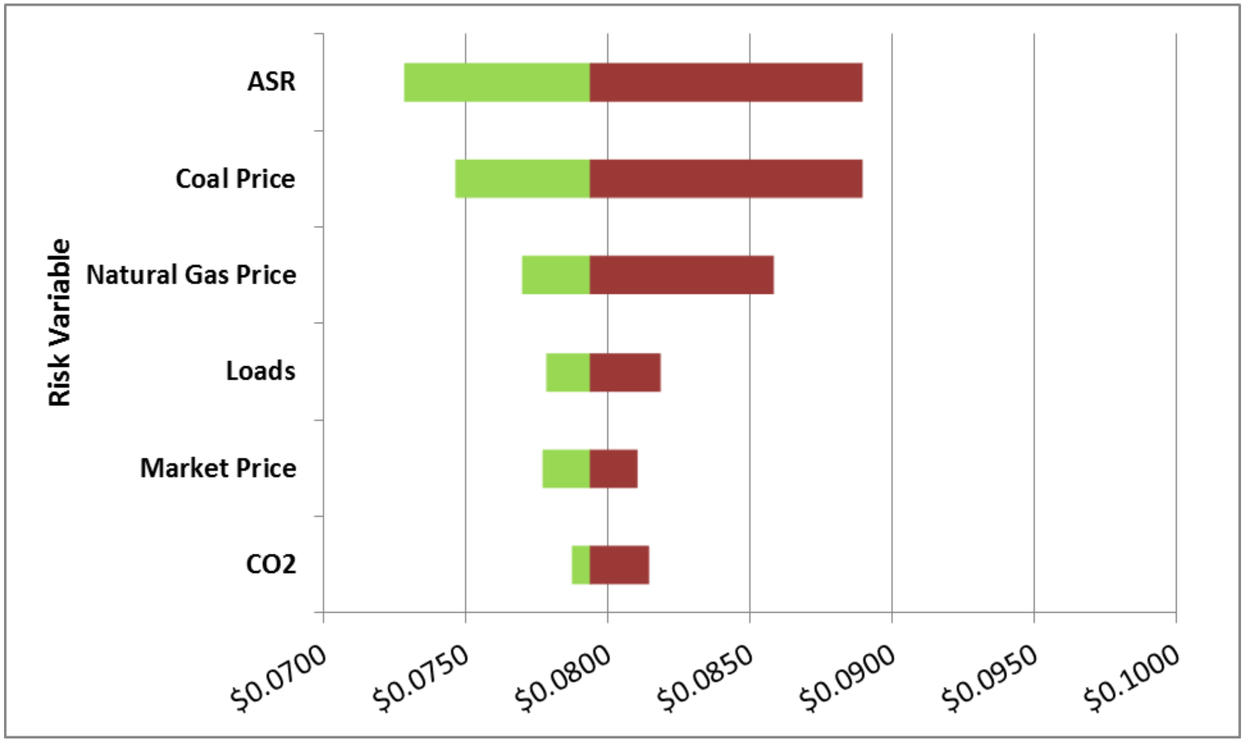
Risk Profile Observations: The figure below illustrates all three cases with the gray range illustrating the range of outcomes for the High Growth Case. In contrast to the Green Case, the p95 event in the High Growth Case is roughly the mean for the Base Case. Similar to the Base and Green Cases, however, the High Growth Case shows little difference prior to 2026 when compared to the other cases. The gray/green shaded area represents overlap between the higher High Growth Case outcomes and the lower Green Case outcomes.

Figure 108 Plan03 Risk Profile



Tornado Chart Observations: The following tornado charts illustrate the risk associated with selected risk variables in the High Growth Case. Absent any environmental policy, risk in the High Growth Case reflects traditional drivers of energy supply risk with fuel and load uncertainty being the top drivers of risk. While IMPA modeled CO_2 as a potential occurrence, the risk to the ASR was negligible.

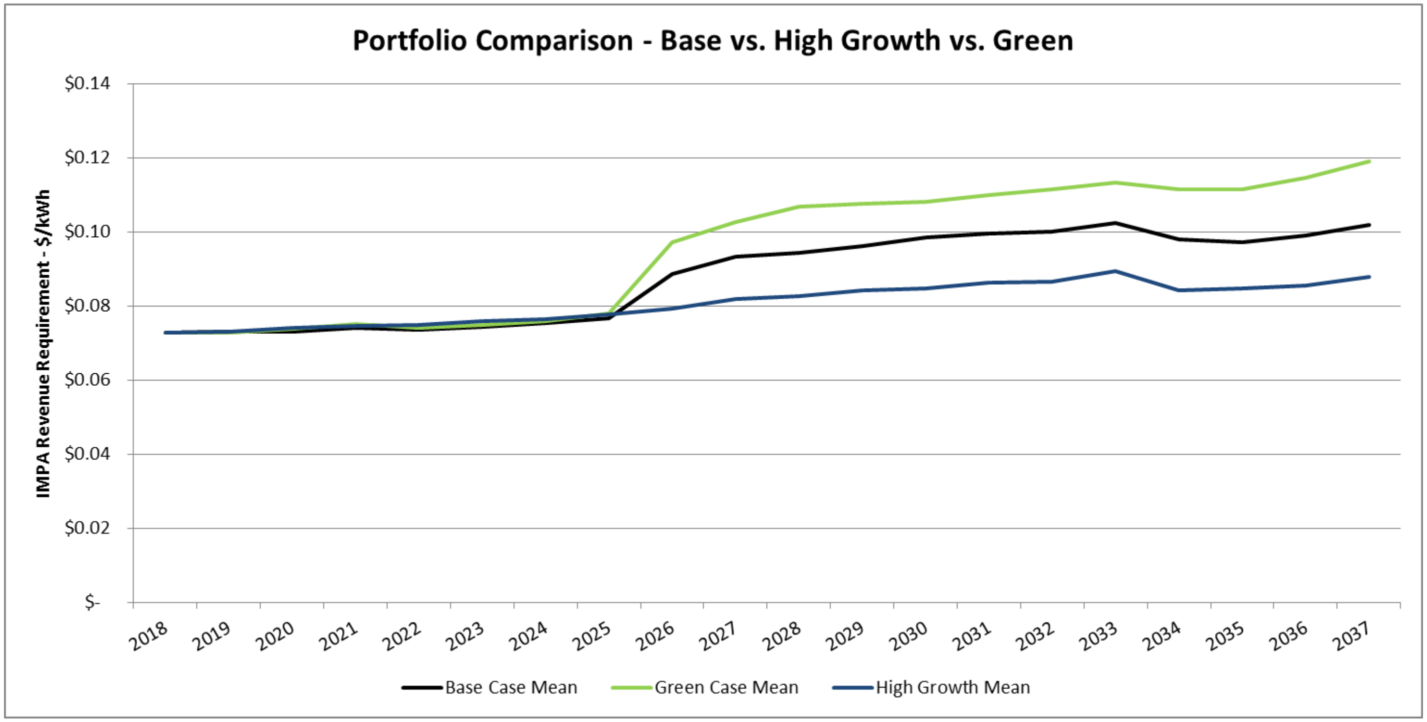
Figure 109 High Growth Case Tornado Charts



15.5 Plan Summary Results

Stochastic Mean Comparison: With a liquid purchased power market to use as a hedge, IMPA can take advantage of the low price market for at least the next five to seven years. As such, all three cases share a similar cost profile until 2026, with the Green Case having a slightly higher revenue requirement due to the higher carbon prices and the requirement to meet the assumed Federal RPS. Drivers of divergence in 2026 and beyond are a function of policy matters (e.g., carbon pricing) and as such, will have to be monitored on an ongoing basis with respect to potential impacts to the portfolio.

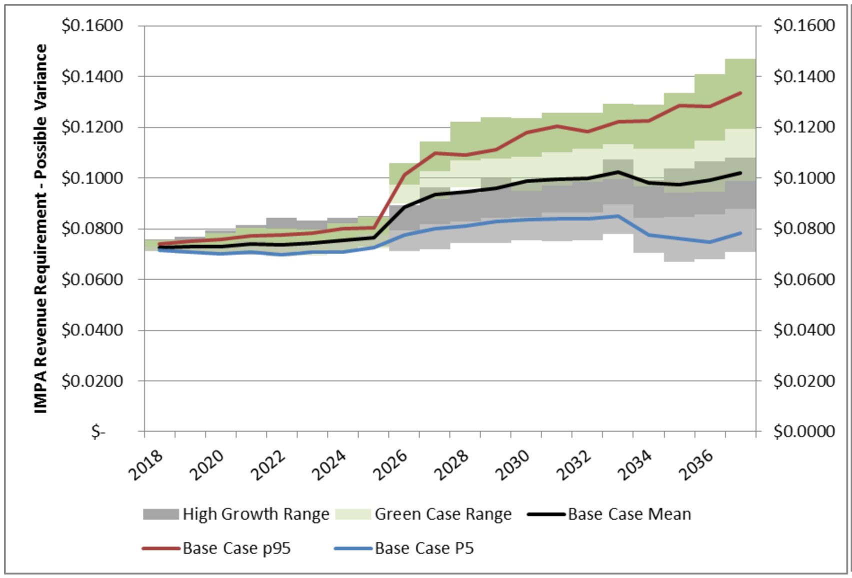
Figure 110 All Plans - Stochastic Mean Comparison

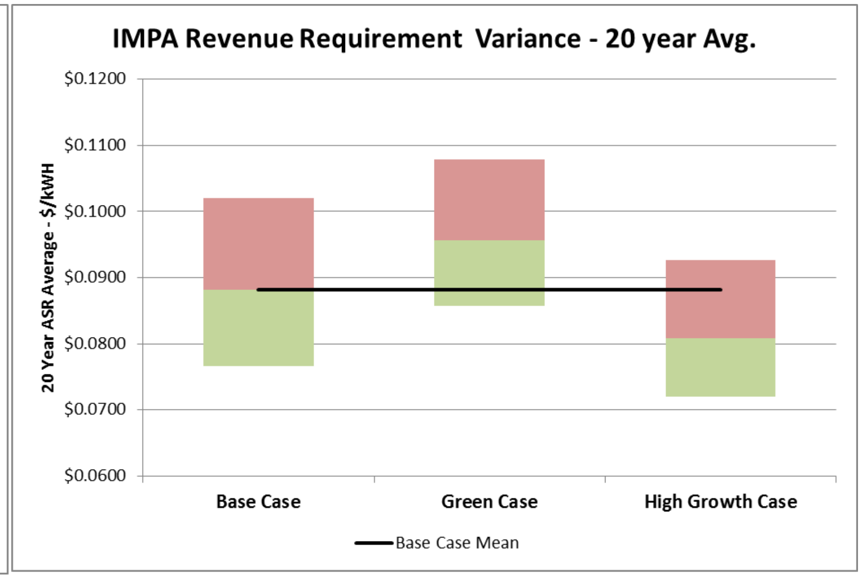


Risk Profile Comparison: The figures below compare risk across all three cases over time. The figure on the left illustrates the mean and P5/P95 for the Base Case, in addition to the range of outcomes between the P5/P95 for the Green and High Growth Cases. The grey/green shaded area represents areas where there is risk outcome overlap between the High Growth and Green Cases.

The figure on the right illustrates levelized 20 year variance from the Base Case mean. As illustrated, the Green Case is expected to lead to a system cost that is roughly 9% higher while the High Growth Case has a system cost that is expected to be 8% lower than the Base Case.

Figure 111 All Plans - Risk Profile Comparison





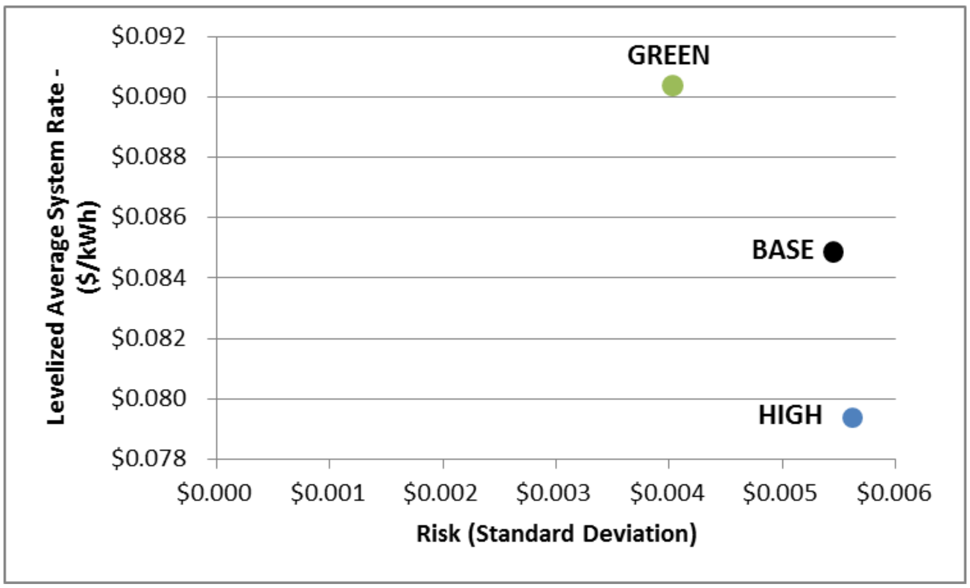
15.6 OTHER EVALUATION TECHNIQUES

IMPA utilizes other techniques to compare the results of the three plans. These techniques are highlighted in the following sections.

15.6.1 ASR Efficient Frontier

An efficient frontier diagram plots the standard deviation on the x-axis and the levelized ASR on the y-axis for each plan. As illustrated, the Green Case has the highest average system rate with the lowest risk. Given that the Base Case is optimized around a different policy regime that the Green Case, it does suggest that IMPA is being rewarded for taking some risk with respect to policy in the form of a lower ASR. The High Growth portfolio is the lowest cost and but highest risk portfolio as it hedges very little policy risk.

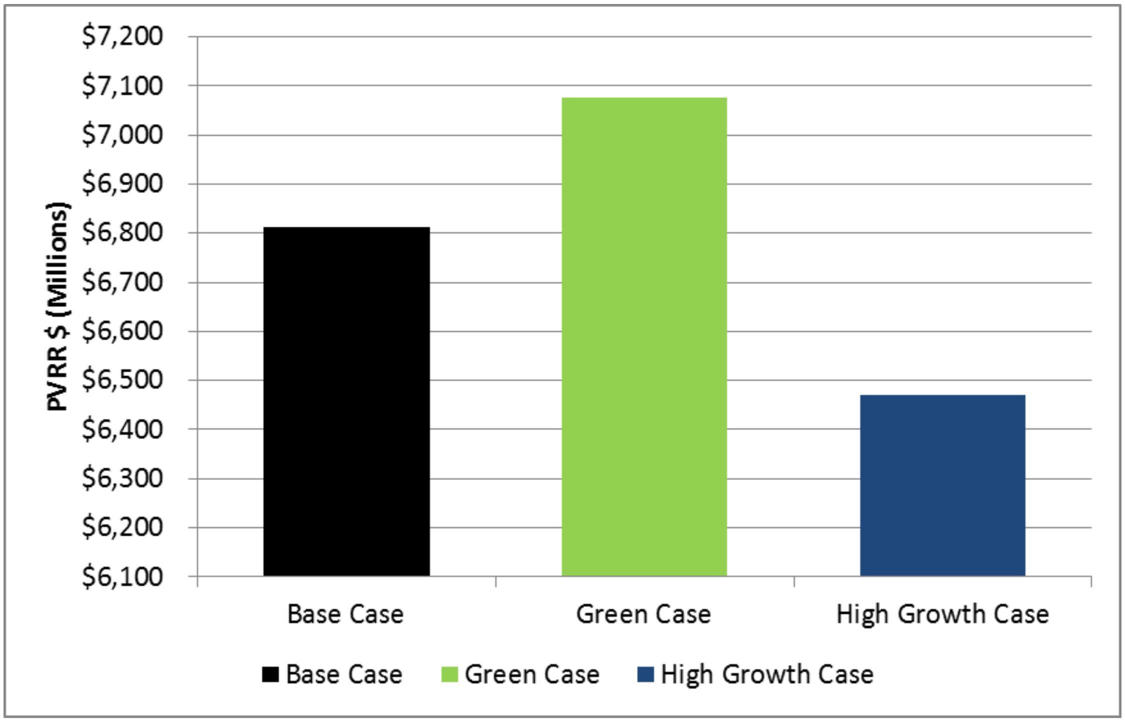
Figure 112 ASR Efficient Frontier



15.6.2 Present Value Revenue Requirements

The following figure shows IMPA's levelized present value revenue requirements (PVRR) for the three plans, with the Green Case showing the highest PVRR of the three cases. The additional cost associated with the Green Case can be thought of as the incremental cost of higher carbon taxation and the Federal RPS requirement.

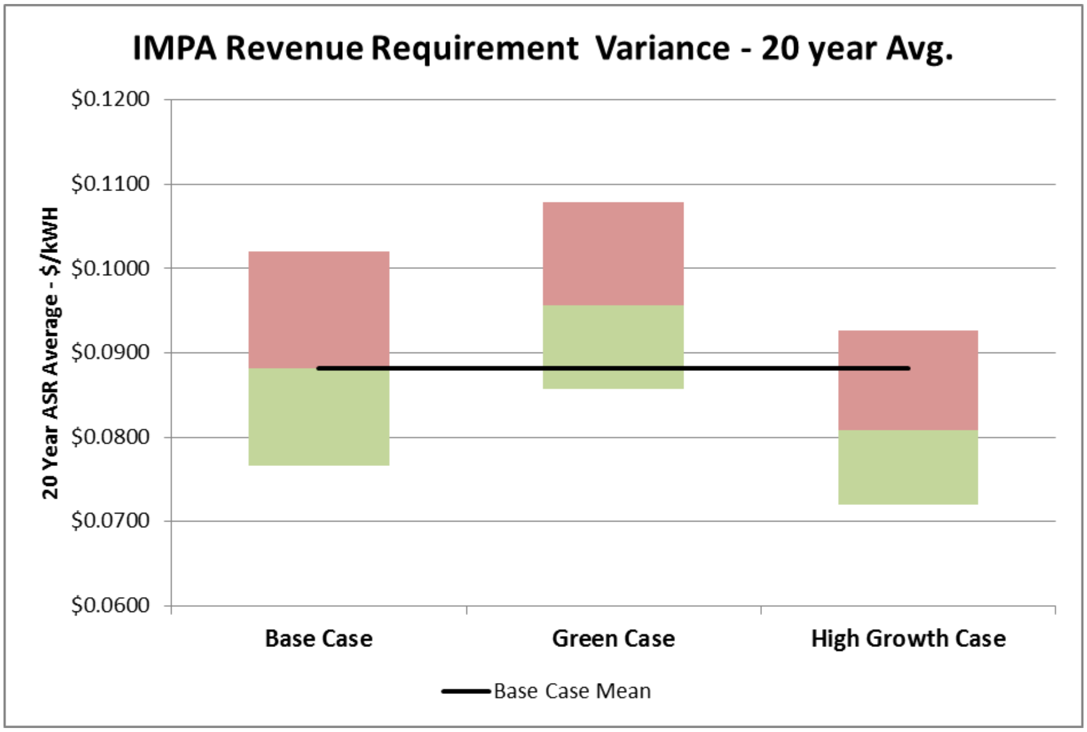
Figure 113 Present Value Revenue Requirements Chart



15.6.3 ASR Risk Confidence Bands

The following figure identifies the risk confidence band (5% - 95%) of each plan where the green bar represents good outcomes relative to the mean and the red bar represents bad outcomes relative to the mean. Of the two cases with an assumed carbon tax, the Green Case shows lower overall risk when compared to the Base Case, largely due to the portfolio being optimized around a very green worldview. However, lower risk comes at an increased cost, relative to the Base Case. The High Growth Case has the lowest overall cost but highest risk of the three cases due to the lack of portfolio action that needs to be taken to respond to environmental policies and regulations, yet with a small probability of a policy being put into place (i.e., a carbon tax).

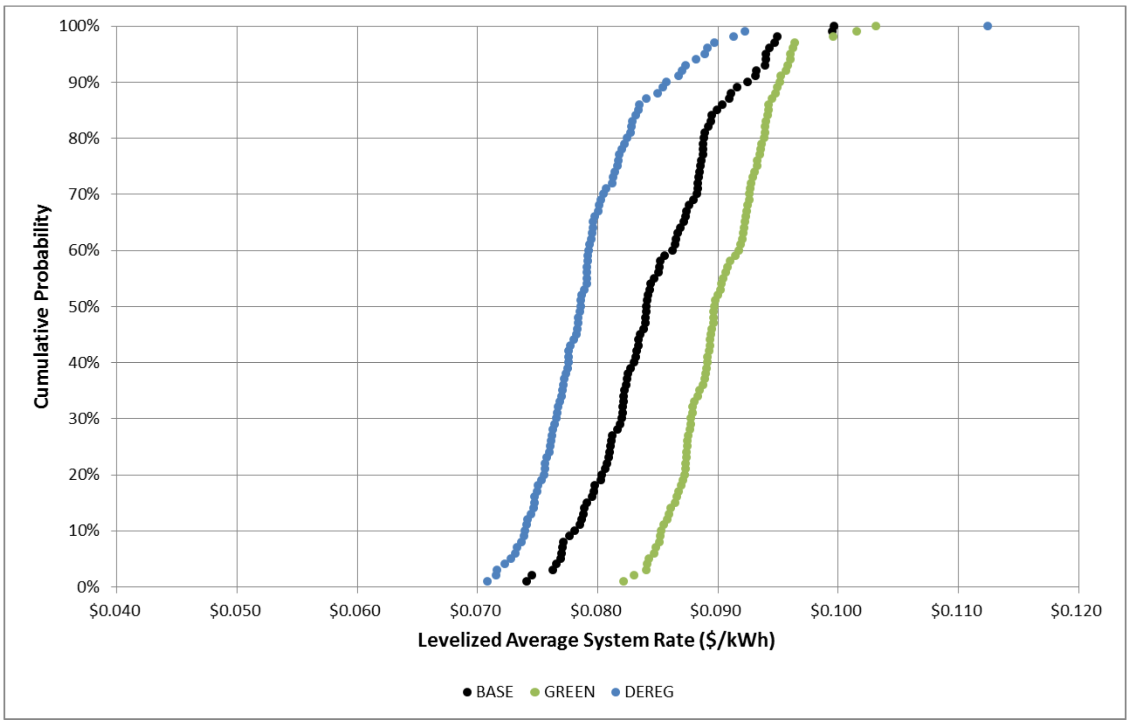
Figure 114 ASR Risk Confidence Bands



15.6.4 ASR S-Curves

S-Curves capture the cumulative probability distribution for a set of variables. In this figure, the steeper slope a curve has the less risk in that curve. If a curve was shown to be vertical, that curve would have zero risk. In the figure below, each of the three scenarios' ASR and range of outcomes is graphed in intervals. The expected system cost can be found at the 50% cumulative probability interval. As shown, the Green Case has the lowest expected risk despite the higher cost. This is largely a function of crafting a portfolio that is mostly insulated from policy uncertainty. Conversely, the lowest cost portfolio is the High Growth Case, which has an observation in excess of $.11/kWh. This reflects a portfolio that is largely unhedged against the potential of climate policy action.

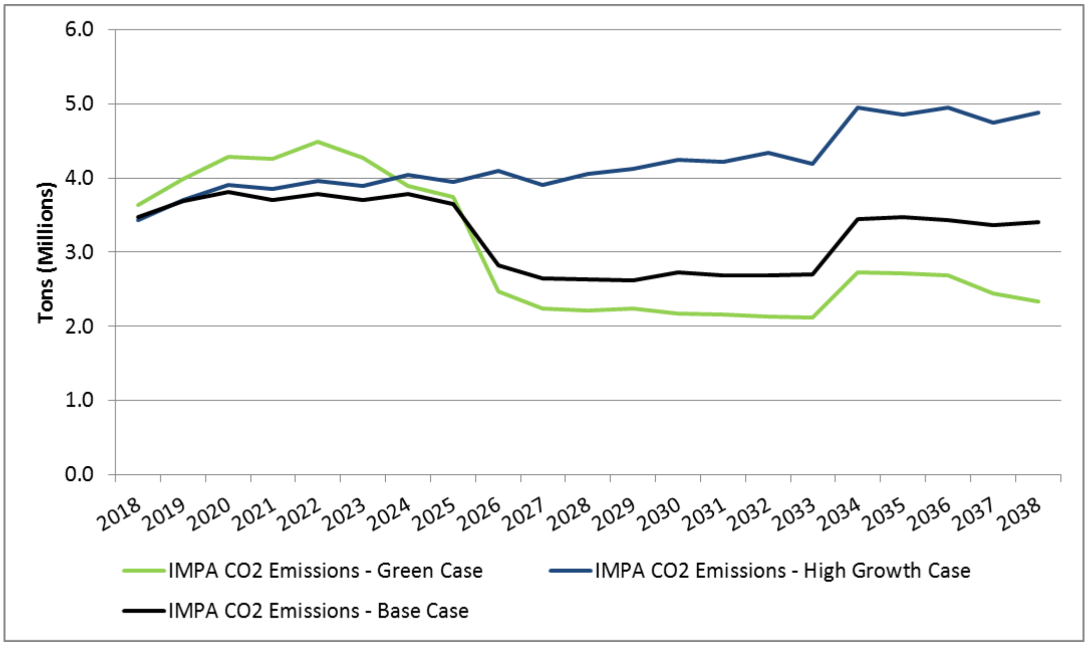
Figure 115 ASR S-Curves



15.6.5 CO_2 Emissions

The following figure shows the tons (millions) of CO_2 emissions of each plan over time. Notably, in the near term, the Green Case has higher CO_2 emissions due to the aggressive retirement of non-IMPA assets in the footprint. This increases the utilization of IMPA assets in the regions and thus increases IMPA's CO_2 output. As IMPA coal fired units begin to be retired, IMPA's CO_2 output begins to decline.

Figure 116 Average CO_2 Emissions (Tons - millions)



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16 PLAN SELECTION

16.1 PLAN SELECTION

As shown throughout this report, due to pending contract expirations, IMPA is losing approximately 100 MW of capacity in the next five years, with potential incremental needs of an additional 100 MW. Based on the analysis of this report and under the assumptions outlined previously, IMPA will pursue the Base Case plan for the foreseeable future, barring a dramatic shift in policy.

The following tables show IMPA's load and capacity balance assuming no new resources are added in the future, compared to the Base Case which adds resources to meet IMPA's reserve margin requirements.

IMPA's position in the market place is such that in the near term it can take advantage of low price bi-lateral capacity market prices to fulfill capacity obligations in MISO without needing to build new assets. IMPA intends to take advantage of this market dynamic for the foreseeable future.

As illustrated previously, a material risk to IMPA's power supply portfolio is the potential for environmental policy, either in the form of carbon taxation, renewable portfolio standards or a combination of both. Given the current policy backdrop, the most likely scenario is that there is relatively low risk of such policies being enacted in the near term, barring a major disruption to the current administration. Nevertheless, given the risk the potential for such policy presents to IMPA, it is prudent to at least hedge a portion of these risks. The Base Case plan calls for the addition of adding wind to the portfolio in 2019 and again in 2026. This allows IMPA to layer into a policy hedge in effect while also preserving the ability to take a "wait and see" approach with respect to carbon policy. In addition, IMPA continues to pursue solar development in member communities, which also serves as an incremental carbon policy hedge.

Based on the analysis of this report and under the assumptions outlined previously, IMPA will pursue the Base Case plan for the foreseeable future, barring dramatic shifts in either the policy or market landscape.

Table 18 Base Case Capacity Balance – Before Additions

Note that capacity reflected here is summer capacity for thermal units while renewable capacity has been reduced by 85% for wind resources and 50% for solar.

Resource/Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Coal	621.6	621.6	621.6	621.6	621.6	621.6	621.6	621.6	521.9	521.9
Existing Gas - CT	366.9	366.9	366.9	366.9	366.9	366.9	366.9	366.9	366.9	366.9
Existing Fuel Oil	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Existing Wind	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing and Planned Solar	18.0	23.5	29.4	35.1	40.9	46.6	52.3	57.9	63.5	69.1
Existing Contracts	296.5	296.5	296.5	196.5	196.5	196.5	196.5	196.5	196.5	196.5
Planned Gas - CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Planned Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Planned Bi-lateral Capacity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Reources	***1,315***	***1,313***	***1,319***	***1,225***	***1,230***	***1,236***	***1,242***	***1,247***	***1,153***	***1,159***
Total Peak + Reserves (15%)	*1,321*	*1,324*	*1,332*	*1,334*	*1,338*	*1,342*	*1,351*	*1,354*	*1,361*	*1,367*

Resource/Year	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Existing Coal	521.9	521.9	521.9	521.9	521.9	521.9	521.9	521.9	521.9	521.9
Existing Gas - CT	366.9	366.9	366.9	366.9	366.9	366.9	366.9	366.9	366.9	366.9
Existing Fuel Oil	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Existing Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing and Planned Solar	74.6	74.1	73.5	73.0	72.5	72.0	71.5	71.0	70.5	70.0
Existing Contracts	196.5	196.5	196.5	196.5	196.5	196.5	0.0	0.0	0.0	0.0
Planned Gas - CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Planned Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Planned Bi-lateral Capacity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Reources	***1,164***	***1,164***	***1,163***	***1,163***	***1,162***	***1,162***	***965***	***964***	***964***	***963***
Total Peak + Reserves (15%)	*1,376*	*1,382*	*1,390*	*1,399*	*1,410*	*1,415*	*1,453*	*1,463*	*1,473*	1,478

Figure 117 Base Case Capacity Balance – Before Additions

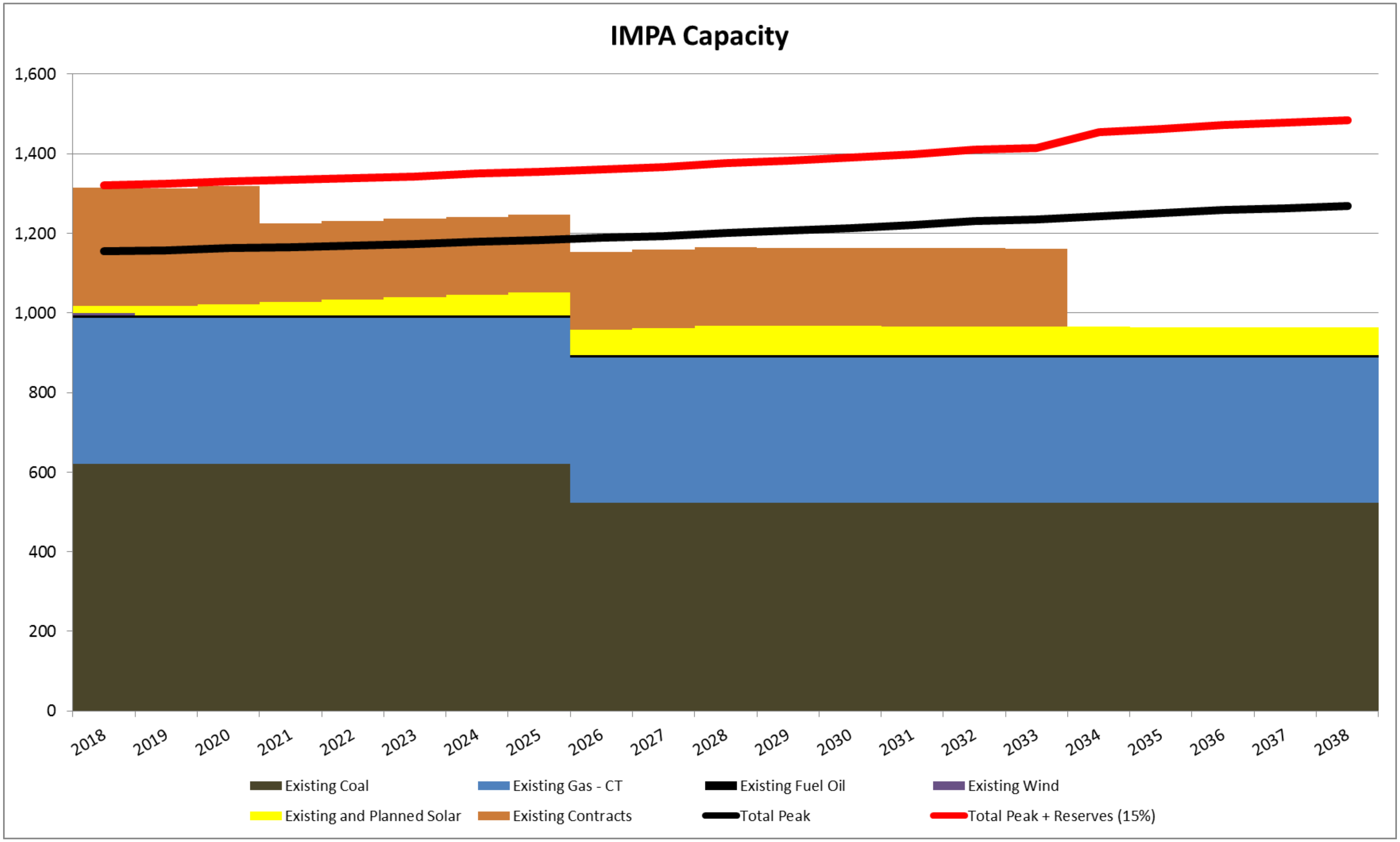


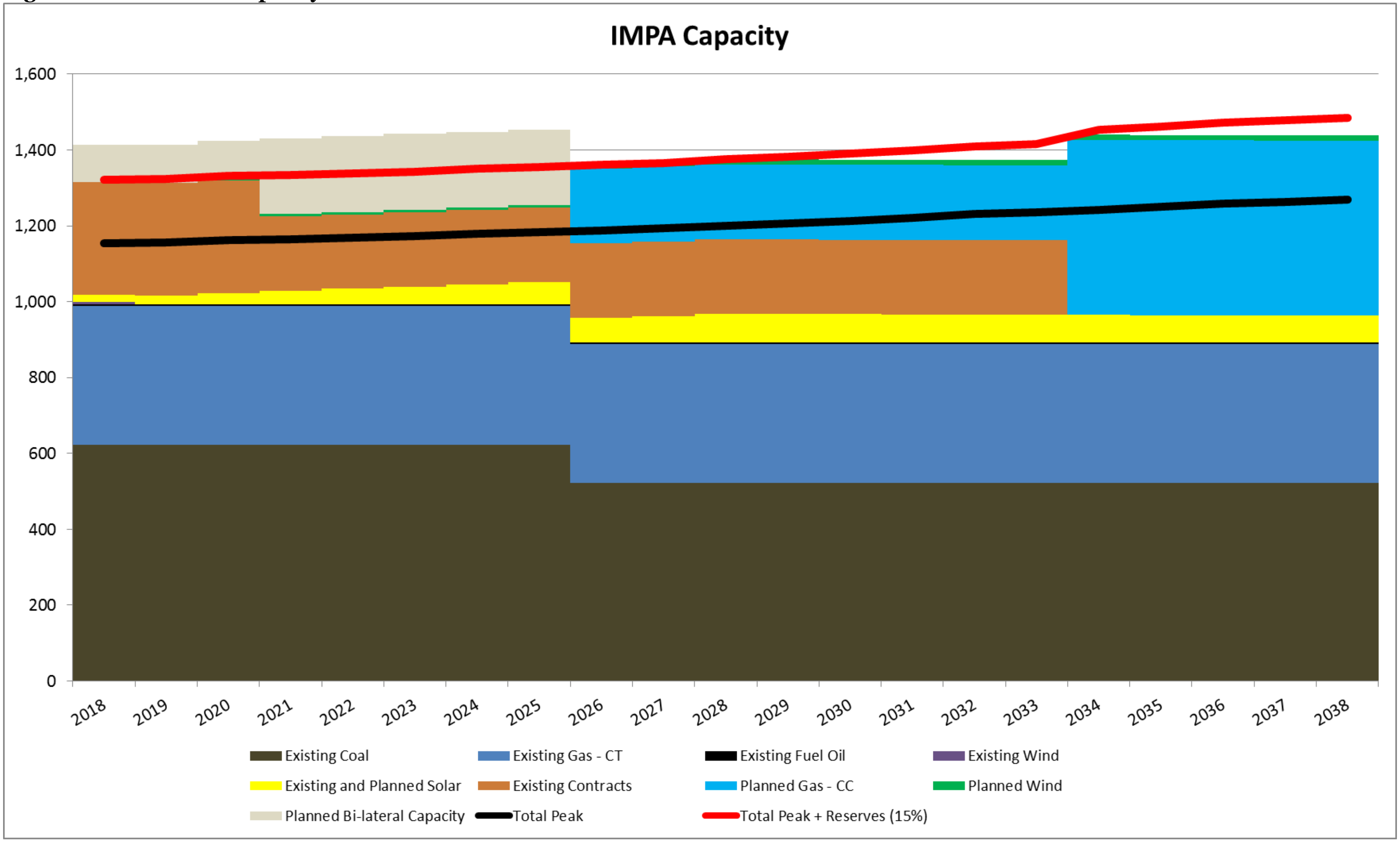
Table 19 Base Case Capacity Balance – After Additions

Resource/Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Existing Coal	621.6	621.6	621.6	621.6	621.6	621.6	621.6	621.6	521.9	521.9
Existing Gas - CT	366.9	366.9	366.9	366.9	366.9	366.9	366.9	366.9	366.9	366.9
Existing Fuel Oil	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Existing Wind	7.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing and Planned Solar	18.0	23.5	29.4	35.1	40.9	46.6	52.3	57.9	63.5	69.1
Existing Contracts	296.5	296.5	296.5	196.5	196.5	196.5	196.5	196.5	196.5	196.5
Planned Gas - CC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	197.6	197.6
Planned Wind	0.0	0.0	6.1	6.1	6.1	6.1	6.1	6.1	13.6	13.6
Planned Bi-lateral Capacity	100.0	100.0	100.0	200.0	200.0	200.0	200.0	200.0	0.0	0.0
Total Reources	***1,415***	***1,413***	***1,425***	***1,431***	***1,437***	***1,442***	***1,448***	***1,454***	***1,364***	***1,370***
Total Peak + Reserves (15%)	*1,321*	*1,324*	*1,332*	*1,334*	*1,338*	*1,342*	*1,351*	*1,354*	*1,361*	*1,367*

Resource/Year	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Existing Coal	521.9	521.9	521.9	521.9	521.9	521.9	521.9	521.9	521.9	521.9
Existing Gas - CT	366.9	366.9	366.9	366.9	366.9	366.9	366.9	366.9	366.9	366.9
Existing Fuel Oil	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5
Existing Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Existing and Planned Solar	74.6	74.1	73.5	73.0	72.5	72.0	71.5	71.0	70.5	70.0
Existing Contracts	196.5	196.5	196.5	196.5	196.5	196.5	0.0	0.0	0.0	0.0
Planned Gas - CC	197.6	197.6	197.6	197.6	197.6	197.6	461.6	461.6	461.6	461.6
Planned Wind	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6	13.6
Planned Bi-lateral Capacity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Reources	***1,376***	***1,375***	***1,375***	***1,374***	***1,373***	***1,373***	***1,440***	***1,439***	***1,439***	***1,438***
Total Peak + Reserves (15%)	*1,376*	*1,382*	*1,390*	*1,399*	*1,410*	*1,415*	*1,453*	*1,463*	*1,473*	1,478

The figure below illustrates IMPA's capacity position after planned additions. Excess capacity in PJM combined with accounting for MISO coincidence factors creates a slightly long position until 2026, at which point the position flattens.

Figure 118 Base Case Capacity Balance – After Additions



16.2 RISKS AND UNCERTAINTIES

As discussed elsewhere in this report, there are many uncertainties facing the electric power industry over the next decades. The following factors are just some of many that could greatly change the future of IMPA, Indiana and the nation:

- CO_2 legislation
- Generation retirements due to known EPA regulations
- New and unknown EPA regulations
- Shale gas/ liquefied natural gas export
- State or federal renewable mandates
- Global and national economic conditions

IMPA's stochastic analysis, discussed in detail in section 14 and 15, attempted to incorporate many of these risks and uncertainties. IMPA assumes that by continuing its long held corporate concept of resource diversity, the plan herein is able to weather these potential uncertainties. The key is that there is flexibility in the plan. By embarking on the process discussed above, IMPA can select the best option among those listed and still leave itself the flexibility to react to changes in political and market conditions.

17 SHORT TERM ACTION PLAN

17.1 ACTION(S) REQUIRED TO IMPLEMENT THE PLAN

While IMPA has a need for capacity and energy over the next four years (2018-2021), those needs will be fulfilled through market purchases as the positions are relatively small. IMPA's next resource decision comes in 2021 when a 100 MW PPA expires. IMPA can hedge these needs with bi-lateral capacity transactions under the current capacity market construct in the MISO market. Based on quotes received for these products, replacing expiring capacity with bi-lateral capacity purchases is in the best interest of IMPA stakeholders. Looking beyond this period and assuming some sort of carbon policy, IMPA would need to participate in roughly 200 MW of combined cycle generation around 2026 to replace both capacity and displaced, carbon intensive generation.

IMPA developed two additional plans to gauge the impact of either no regulation or more stringent regulation as sensitivities to the Base Case. While the current backdrop is potentially biased towards outcomes associated with the High Growth Scenario, IMPA plans on taking advantage of sun-setting tax credits on renewables by layering into utility-scale wind and continued deployment of IMPA's solar parks. Actions taken under the Base Case are consistent with IMPA's stated mission of providing power that is low cost, reliable and environmentally responsible.

Action Plan Items

1. Secure bilateral capacity in the five to seven year term
2. Secure market energy needs for same time frame
3. Continue monitoring the federal legislative process in order to gain more clarity on the future of CO_2 legislation
4. Continue IMPA Solar Park Program
5. Investigate replacement of 50 MW Crystal Lake wind contract
6. Continue with IMPA Energy Efficiency Program
7. Continue to develop IMPA's modeling capabilities in the areas of:
    - Zonal Optimization/Market Price Development
    - Portfolio Optimization
    - Stochastics and Risk Identification/Mitigation
    - Nodal analysis

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18 IRP GUIDELINES (170 IAC 4-7)

18.1 INDEX OF RULES AND REPORT LOCATION REFERENCE

Current Rule

170 IAC 4-7 Reference	Description	Reference
4.1	External data sources	Section 9.4 Appendix D Appendix E
4.2-4.6	Load Forecasting Matters	Section 4 Section 5
4.7-4.9	Miscellaneous planning criteria and practices	Section 3.3 Section 4.3 Section 7.1
4.10-4.15	Transmission Matters	Section 4.5 Section 8.1 Appendix G
4.16	Explanation of avoided cost calculation	Appendix F
4.17	Hourly System Demand of the most recent historical year	Appendix A
4.18	Description of public participation procedure, if used.	IMPA solicits input from the IMPA Board of Commissioners when developing scenarios. IMPA's IRP is presented to the Board on two occasions with formal approval taking place after initial Board input and a second presentation.
5	Analysis of historical and forecasted levels of peak demand. Forecast scenarios.	Section 4.2 Section 5 Appendix B
6	Resource Assessment	Section 4 Section 6 Section 7 Appendix D Appendix E Appendix F
7	Selection of Future Resources	Section 6 Section 7 Section 13 Section 15 Section 16

8	Resource Integration	Section 15 Section 16
9	Short-term Action Plan	Section 17

Proposed Rule (New Rule References)

4(a)	IRP Summary Document	Appendix I
4(b)10	Miscellaneous Transmission	Section 4.5 Section 8.1 Appendix G
4(b)11	Contemporary Methods, Model Selection and Description	Sections 9-16
6(a)	Continued use of existing resource as a new resource alternative	Section 6.1 Section 12.2
8(a)	Candidate portfolios	Section 13
8(b)	Demonstrate how preferred resource portfolio balances cost-effective minimization with effective risk and uncertainty reduction.	Section 14 Section 15

19 APPENDIX

A. Hourly System Loads
B. Historic System Load Shapes
C. C1 - Hourly Market Prices – Indiana Hub
   C2 - Hourly Market Prices – AD Hub
D. D1 - Existing Resource Data – Summary
   D2 - Existing Resource Data – Detailed
E. Expansion Resource Data
F. Avoided Costs
G. Statement on FERC Form 715
H. H1 - 2016 IMPA Annual Report
   H2 - 2016 IMPA Annual Report - Financials
I. IRP Summary Document