2020 Integrated Resource Plan

November 2, 2020

IMPA

INDIANA MUNICIPAL POWER AGENCY

Indiana Municipal Power Agency

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ACRONYM INDEX

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
PPI	Producer Price Index
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

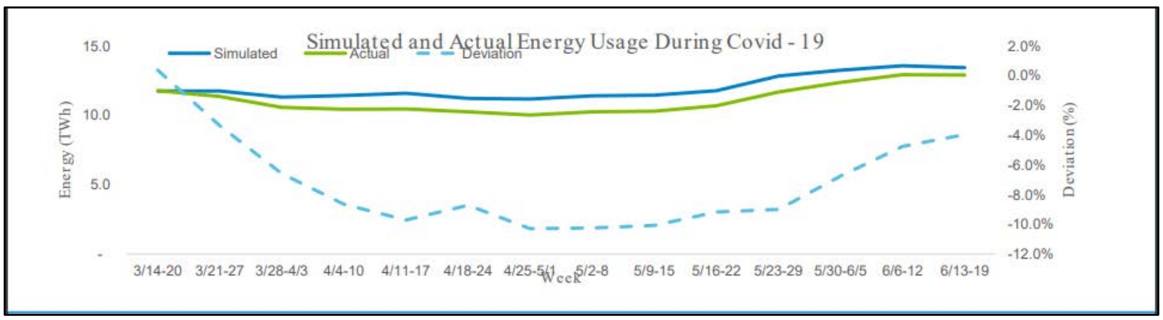
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
T&LF	Transmission and Local Facilities Agreement
TDU	Transmission Dependent Utility
TO	Transmission Owner
TW	Terawatt
TWh	Terawatt Hour
UCAP	Unforced Capacity
VOM	Variable Operation and Maintenance
WOTUS	Waters of the United States
WVPA	Wabash Valley Power Association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

1 PREFACE

Utility planners face unprecedented uncertainty in 2020. What started as a relatively normal year with relatively normal expectations for economic activity, unfolded into a morass of a pandemic, economic uncertainty, social unrest, and political uncertainty. All in an election year no less. Perhaps the most challenging aspect of planning in the current environment is determining impacts to load forecasts. With what has evolved into a "pandemic economy" of employees working from home, businesses closing and furloughing workers, several questions have arisen and persist. Will business recover? If so, when? What is the time horizon for a recovery if it happens? Will the recovery be "V-shaped", "W-shaped" or some other trajectory? Does a recovery hinge on the success of a vaccine for COVID-19? Unprecedented times indeed.

As COVID-19 spread in early 2020, utility staff everywhere attempted to quantify impacts to load. By mid-April, the Midcontinent Independent System Operator and PJM RTO published weather corrected load forecasts using their models to determine impacts from COVID-19 and related stay at home orders. By mid-June MISO reported that loads were slowly recovering as states began lifting COVID-19 restrictions with load and demand deviations being down roughly 5% versus the 10% observed in May.

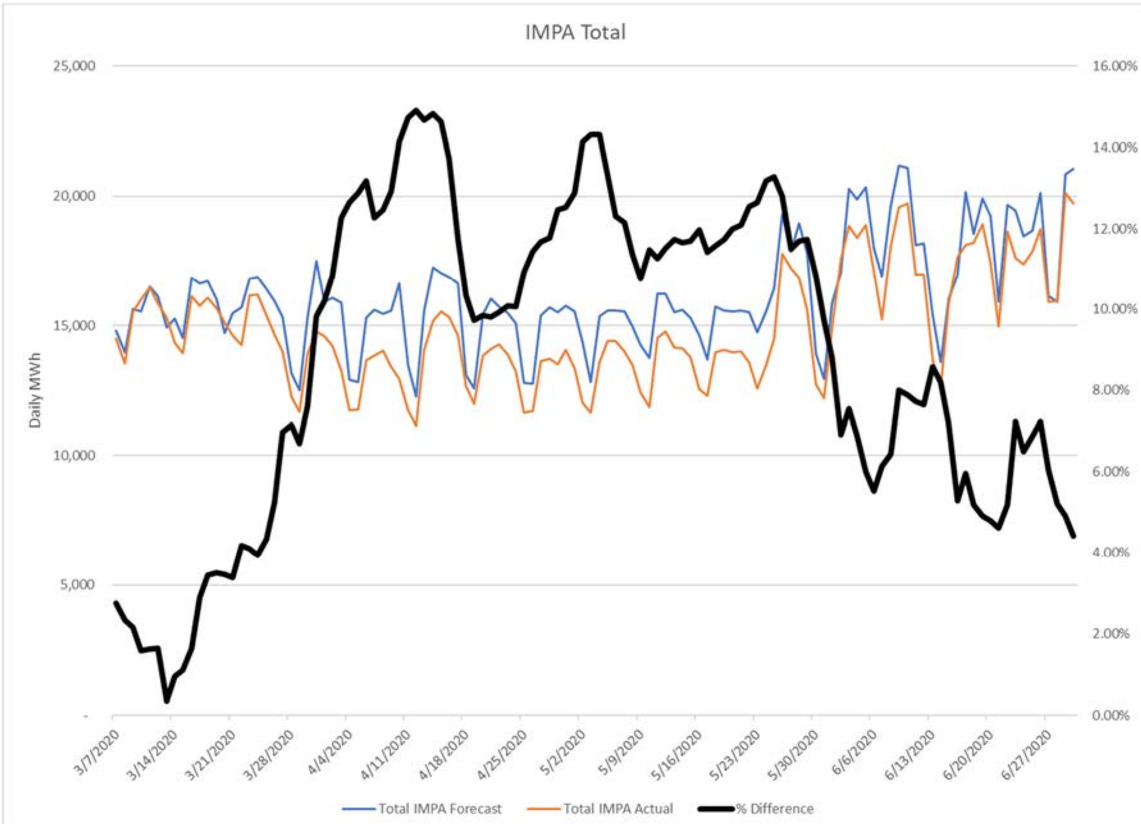
Figure 1 MISO COVID Backcast



The PJM RTO also published their estimate of COVID impacts to system loads and those estimates at the time of writing are comparable to MISO estimates of around 10% and gradually trending back as stay at home orders began being lifted.

IMPA is seeing similar trends in its deviations from load forecast, with loads generally coming in around 8% under forecast with similar rebounds as stay at home orders were lifted.

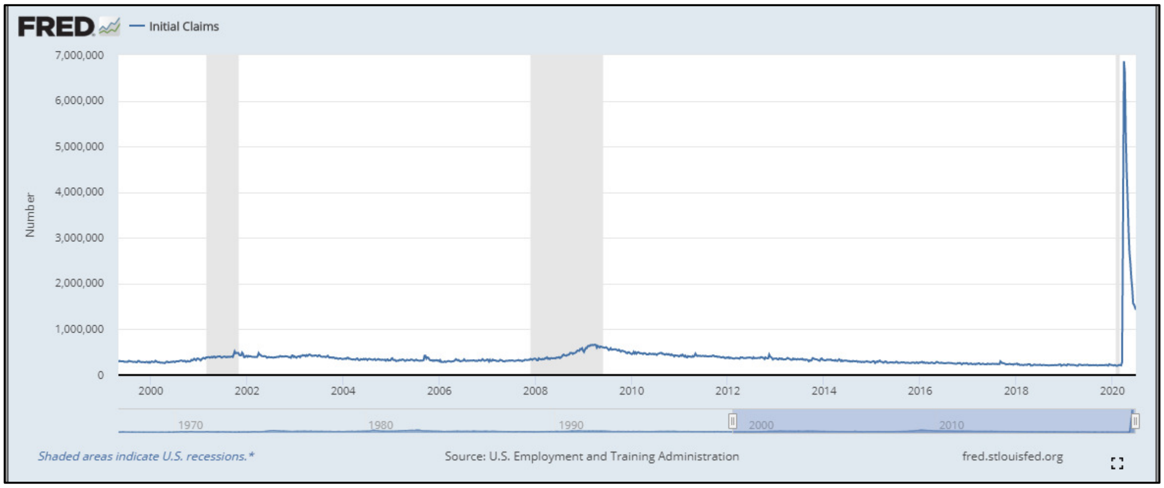
Figure 2 IMPA COVID Backcast



Perhaps the most challenging aspect, however, is determining what, if any change should be made to the long-term load forecast. Historically, IMPA has been comfortable with its load forecast variables and the forecast model's explanatory power. To improve the forecast in the face of COVID-19, IMPA staff attempted to incorporate macroeconomic variables that would be sensitive to COVID-19. This included but were not limited to Producer Price Index (PPI), Indiana ongoing jobless claims, ADP Construction Payrolls, ADP Manufacturing Payrolls, and average weekly jobless claims. It became rapidly apparent that regression models would not be able to sufficiently explain or capture movements seen in those variables as they became impacted by COVID-19. For example, initial jobless claims in the first weeks of the COVID-19 outbreak were unfathomable and were such an outlier that they caused the regression model to fail. The figure below illustrates the magnitude of shock seen in jobless claims in early 2020. [1]

[1] https://fred.stlouisfed.org/series/ICSA

Figure 3 Historic Unemployment Claims



Furthermore, a number of economists were seeing COVID-19 related economic impacts as being "V shaped", meaning a sharp decline followed by a sharp recovery. As recently as early June, CNBC was reporting that data was indeed pointing to a V-shaped recovery and even cited Apple mobility data that showed map requests were recovering to pre-COVID-19 levels. [2] However, by late June and early July, a worrying increase in COVID-19 cases and hospitalizations among states who aggressively reopened seemed to cast doubt on the potential for a V-shaped recovery.

Increasing uncertainty on both a demand front and policy front only increases risks that load serving entities make a costly mistake for their ratepayers/stakeholders. Overcommitment and overreliance on a particular fuel or technology could result in a load serving entity burdened with a stranded investment at some point in the future. Furthermore, COVID-19 presents the risk, particularly in communities served by IMPA, of long-term demand destruction. While IMPA remains optimistic that load related impacts being seen in 2020 are slowly reversing themselves, they have yet to recover to pre-COVID-19 forecasts.

The plan outlined in the following report may very well change depending on the outcomes of the pandemic and elections. IMPA believes the best way to combat this uncertainty is to rigorously plan for the best expectation of future events based on information that is currently known. More importantly, IMPA believes in the power of being adaptable and nimble as market conditions dictate. By doing this, IMPA can continue to supply wholesale power to our 61 communities. Power that is low cost, reliable and environmentally responsible.

[2] https://www.cnbc.com/2020/06/05/the-recovery-from-the-coronavirus-sure-looks-v-shaped-going-by-these-charts.html

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2 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 2020 Integrated Resource Plan (IRP). This report assesses IMPA's options to meet its members' capacity and energy requirements for wholesale service from 2021 through 2040.

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 2019, IMPA's coincident peak demand for its 61 communities was 1,198 MW, and the annual member energy requirements during 2019 were 6,244,150 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.

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);
- 32 Solar Parks located in member communities
- Long term power purchases from:
    - Indiana-Michigan Power Company (I&M)
    - Duke Energy Indiana (DEI)
    - Alta Farms II Wind Farm LLC
    - Ratts Solar Park LLC
- 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. IMPA's generation and contractual resources reside in Indiana, Illinois 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 120,214 MWh at the end of 2019 and a coincident peak reduction of 13.5 MW. In addition to its energy efficiency program, IMPA offers a demand response tariff, an excess renewable generation program, 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 7. 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, planning process and plan selection is discussed in Sections 10 through 14.

2.1 Action Plan

IMPA's preferred resource expansion plan is shown below.

Table 1 2020 IRP Expansion Plan – Preferred Plan

IMPA Base Case Plan - ICAP Capacity (Summer Ratings)					
Planning Year	MW Withdrawn	MW Withdrawn Notes	MW Capacity Added	MW Capacity Added Notes	Net Capacity Added/(Withdrawn)
PY 21-22	-100	Duke Option Expires	72	Increase in Bilateral Contract Qty, IMPA Solar	-28
PY 22-23			111	Increase in Bilateral Contract Qty + IMPA Solar + Alta Farms Wind PPA (Energy Only)	111
PY 23-24			161	Ratts Solar PPA + IMPA Solar	161
PY 24-25			111	Solar PPA (currently in negotiation) + IMPA Solar	111
PY 25-26			111	MISO Z6 Solar Project + IMPA Solar	111
PY 26-27	-231	Gibson #5 Retirement/Bilateral Capacity Expiration	207	Planned Natural Gas Combustion Turbine + IMPA Solar	-24
PY 27-28					
PY 28-29					
PY 29-30					
PY 30-31					
PY 31-32					
PY 32-33					
PY 33-34					
PY 34-35	-286	AEP Contract Expiration/WWVS Retirement	316	Planned NG Combined Cycle and Solar	30
PY 35-36					
PY 36-37					
PY 37-38					
PY 38-39					
PY 39-40					
PY 40-41					

IMPA has a slight short capacity position in PY 21-22, largely driven by a bilateral contract expiration. This position is too small to require a resource, so that requirement will be met with either a bilateral transaction or will be purchased in the MISO Planning Resource Auction. IMPA currently has a contract for 150 MW of solar that is expected to come online for PY 23-24 and is negotiating a contract for 100 MW of solar in the MISO footprint for PY 24-25. These additions serve to diversify IMPA's power supply portfolio and get IMPA to a flat capacity position in the near term. With Gibson 5 retiring in PY 26-27, IMPA's modeling efforts for this IRP suggest that the least cost path forward for replacing this capacity is to replace the loss of Gibson 5 with a natural gas combustion turbine and additional solar. From there, IMPA's needs will be met until the expiration of the AEP contract in PY 34-35. At this time, IMPA expects to replace that contract with a portion of a combined cycle and additional solar. In the immediate term, the IMPA action plan is as follows:

Action Plan Items

1. Continue IMPA Solar Park Program
2. Work with the Gibson 5 partners regarding the plan, timing and cost for retirement of the unit.
3. Begin internal planning for the best path forward for adding CT capacity to its portfolio as a replacement for Gibson 5
4. Maintain regular contact with the marketplace for both financial power and physical solar power in order to optimize IMPA's energy position prior to the expiration of the ITC for solar
5. Explore incremental opportunities for solar off-take as part of the modeled, least cost solution
    a. Analyst cost/benefit of PPA offtake vs. Agency ownership of utility scale solar
6. Continue the IMPA Energy Efficiency Program
7. Continue to utilize the RTO/ISO stakeholder process to monitor market rules regarding renewable capacity accreditation and resource adequacy
8. Monitor elections and the legislative process to remain informed on future environmental policy as it pertains to CO_2
9. Continue to enhance IMPA's modeling capabilities with respect to transmission, capacity/market price formation, and portfolio optimization
    a. To this end, survey the energy software industry to seek potential model alternatives.

Currently, 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.

3 IMPA OVERVIEW

3.1 INTRODUCTION

Pursuant to Indiana Code § 8-1-2.2-1 *et seq.*, IMPA was created in 1980 to undertake the planning, financing, ownership and operation of projects to supply electric power and energy for the present and future needs of the members. IMPA began operation in 1983 with 24 members. IMPA now serves 61 members in Indiana and Ohio. Pursuant to the power sale contract with each of its members, IMPA is the wholesale full requirements power provider for its members. While IMPA's members serve a population of over 330,000 people, IMPA has no retail customers itself.

3.2 KEY EVENTS SINCE LAST IRP

Since IMPA submitted its last IRP to the IURC on February 1, 2018, the following events have taken place:

- In December 2018, the Advance, Rensselaer 2, and Richmond 2 solar parks began commercial operations.
- In January 2019, IMPA entered a contract with Alta Farms II, LLC for up to 75 MW of wind energy.
- In July 2019, the Tipton solar park began commercial operations.
- On October 30, 2019 IMPA closed on the sale of its Power Supply Revenue Bonds, 2019 Series A. The purpose of these bonds was to fund capital improvements on existing Agency assets.
- On December 13, 2019 IMPA closed on the sale of its Refunding Bonds, 2019 Series B. The purpose of these bonds was to refund existing Agency bonds.
- In December 2019, the Crawfordsville 2 & 3, Darlington and Richmond 3 solar parks began commercial operations.
- In January 2020, IMPA entered a contract with Ratts I Solar, LLC for up to 100 MW of solar energy. This contract was subsequently amended to 150 MW.
- In the spring of 2020, the Crawfordsville 4 and Gas City solar parks went into commercial operation.
- In May 2020, IMPA member Rensselaer retired its municipally owned generation plant and terminated the Member Dedicated Capacity Agreement with IMPA.
- In the summer of 2020, the Crawfordsville 5 and Tell City 2 solar parks went into commercial operation.
- In the fall of 2020, the Centerville, Richmond 4 and Scottsburg solar parks went into commercial operation.

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4 IRP OBJECTIVES AND PROCESS

4.1 IRP RULES (170 IAC 4-7)

The IURC developed guidelines in 170 IAC 4-7-1 *et seq*. for electric utility IRPs 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.

4.2 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.

4.3 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. 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 with wind at 15% of nameplate. Solar was, initially, treated as 50% phasing in to 70% which reflect current market rules. However, as a stress test and ultimate planning assumption, IMPA assumes solar capacity credit will float based on the total installed solar capacity within a given footprint.

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.

4.4 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 5)

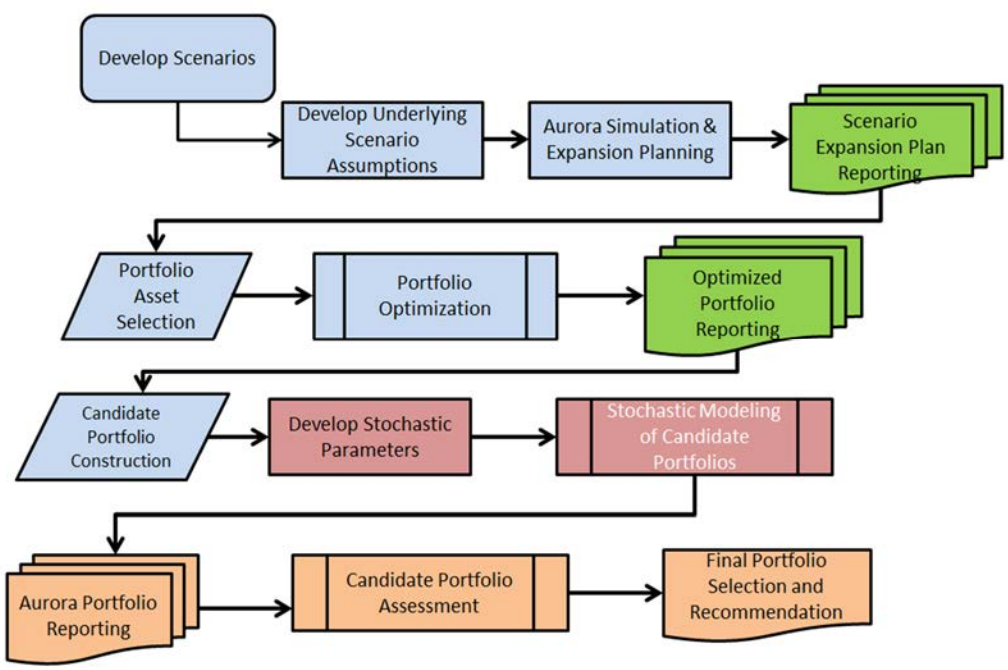
2. Long Range Forecast Development – Annually, IMPA develops a 20-year projection of peak demands and annual energy requirements. The load forecast is developed using a time-series, linear regression equation for each load zone. (Section 6)

3. Resource Options and Environmental Compliance – This step involves the description of various resource alternatives. Additionally, transmission service and compliance with future environmental issues are discussed. (Sections 7-9)

4. Software Overview / Data Sources – This section describes the software and data sources used to perform the analysis. (Section 10)

5. Scenario Development, Assessment and Evaluation – 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. 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. 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 11-13)

   As a broad overview, IMPA utilizes AuroraXMP by Energy Exemplar for its power supply modeling and MCR-FRST by MCR Performance Solutions for financial modeling. The flowchart below illustrates the general process for modeling the IRP.



The process begins with scenario development and their underlying assumptions. From those assumptions IMPA utilizes AuroraXMP to run a system capacity expansion on the entire Eastern Interconnect. AuroraXMP optimizes the system to be the lowest cost possible while maintaining assumed reserve margins for each area.

From this system expansion, IMPA is then able to run the portfolio optimizer contained within Aurora to select optimal assets from the broader system expansion. From there a candidate portfolio is then constructed and run stochastically as part of a risk assessment. The final portfolio selection is based on a combination of Net Present Value of the Revenue Requirement (NPVRR), Average System Rate (ASR), robustness to risk, and emissions profiles. The following sections discuss the creation of formation of each scenario and the resulting optimal portfolios in each of those scenarios.

6. Plan Selection – Description of preferred plan and basis for selection. (Section 14)

7. Short Term Action Plan – Description of steps necessary to implement the preferred plan. (Section 15)

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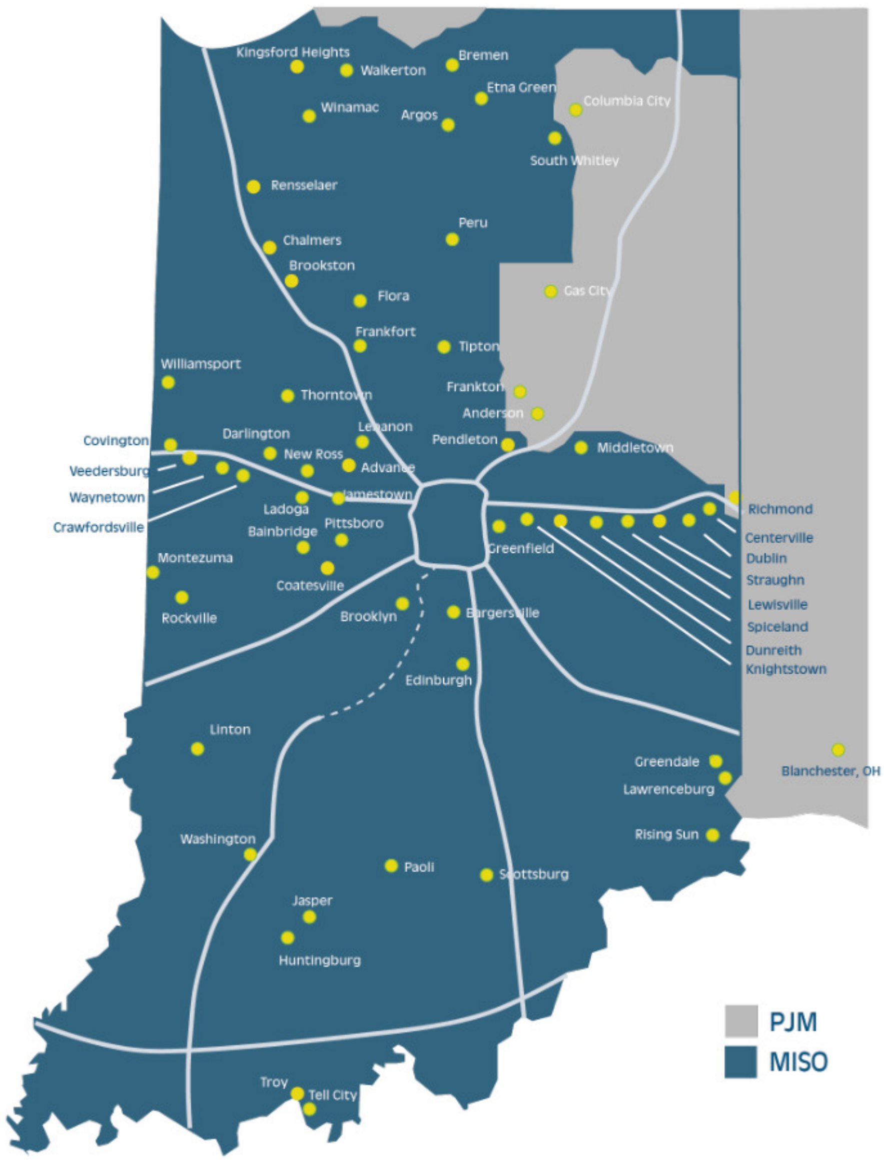
5 EXISTING SYSTEM

5.1 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 member load in five load zones and generation resources connected to six 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 4 IMPA Communities Map



5.2 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 RTO and load zone in which they are located and the approximate percentage of IMPA's total load.

Table 2 IMPA Communities

RTO	Load Zone	% of Load	Community
MISO	Duke-IN	50%	Advance, Bainbridge, Bargersville, Brooklyn, Brookston, 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, 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 2019, IMPA's peak demand for its 61 communities was 1,198 MW, and the annual member energy requirements during 2019 were 6,244,150 MWh.

Hourly loads are shown in Appendix A and typical annual, monthly, weekly, and daily load shapes for IMPA 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.

5.3 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;
- 32 solar parks located in IMPA member communities;
- 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.
- Alta Farms II Wind Farm LLC (COD: 2022)
- Ratts Solar Park LLC (COD: 2023)

Some of these resources have contractual limitations that restrict their use to a particular 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% 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.

As of date of this report, this unit is scheduled to be retired on May 31, 2026. It is removed from IMPA's portfolio effective June 1, 2026 and the plans herein are based upon this unit being out of service. Should this retirement be delayed or not come to fruition, the recommended plan shown in this report may be subject to change.

Trimble County 1

IMPA has a 12.88% 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 the next 22-25 years.

White Water Valley Station

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 White Water Valley Station (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.

IMPA Combustion Turbines

IMPA owns seven 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 for 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 fall of 2020, 32 facilities totaling 106.5 MW had been placed in service. These solar parks range in size from .24 to 9.79 MW. Continued development of solar parks is planned through 2026.

IMPA solar parks are currently operating in the following communities:

Table 3 IMPA Solar Parks

Facilty	MW			Facilty	MW	
Advance	0.24	(PPA)		Huntingburg	2.08	
Anderson 1	4.90	(PPA)		Pendleton	2.04	
Anderson 2	8.35	(PPA)		Peru	3.02	
Argos	0.71			Rensselaer	0.99	
Bainbridge	0.36			Rensselaer 2	3.85	(PPA)
Centerville	1.05	(PPA)		Richmond	1.00	
Crawfordsville	2.98			Richmond 2	7.40	(PPA)
Crawfordsville 2	7.93	(PPA)		Richmond 3	6.47	(PPA)
Crawfordsville 3	4.76	(PPA)		Richmond 4	7.05	(PPA)
Crawfordsville 4	2.32	(PPA)		Scottsburg	7.14	(PPA)
Crawfordsville 5	9.79	(PPA)		Spiceland	0.51	(PPA)
Darlington	0.91	(PPA)		Tell City	1.00	
Flora	0.79	(PPA)		Tell City 2	3.15	(PPA)
Frankton	0.99			Tipton	5.26	(PPA)
Gas City	2.49	(PPA)		Washington	3.91	
Greenfield	2.78	(PPA)		Waynetown	0.27	

Facilities marked "PPA" were developed, designed and constructed by IMPA, and either sold to a third party or originally developed for third party ownership. IMPA purchases 100% of the output from the solar parks under long term PPAs with the third parties.

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 300 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 contract provides dispatchable energy with minimum annual load factor requirements. The demand charge is a negotiated fixed rate while the fuel charge is 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

In January 2019, IMPA entered a contract with Alta Farms II, LLC for the purchase of up to 75 MW of wind energy from the Alta Farms II Wind Farm located in DeWitt County, Illinois. Deliveries are scheduled to begin in the fourth quarter of 2022.

In January 2020, IMPA entered a contract with Ratts I Solar Farm, LLC for the purchase of 100 MW of solar energy from the Ratts I Solar Farm located in Pike County, Indiana. This contract was subsequently amended to increase the offtake amount to 150MW. Deliveries are scheduled to begin by the first quarter of 2023.

IMPA is currently in PPA negotiations with a developer for 100 MW of a solar park to be online in 2024. This PPA is being included in the modeling as an existing contract.

IMPA has entered 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 energy purchases extending to 2026.

Net Metering/Retail Customer-Owned Generation (Renewable)

On January 28, 2009 the Board approved IMPA's net metering tariff. This tariff allowed for the net metering of small renewable energy systems at retail customer locations. As with the Green Power rate, the net metering tariff was implemented at the member's discretion. Currently, there are approximately 20 traditional net metering installations in members' service territories with a totaled installed capacity of approximately 100 kW.

After the passage of SB 309 in which Indiana's net metering laws were changed by the Indiana General Assembly, IMPA changed its policy to an excess customer generation policy. Though IMPA is not bound by this state law, IMPA management believes following the spirit of the state laws avoids confusion to retail customers. Under this program, retail customers may install any renewable systems they wish. Like the state law, any power generated in excess of instantaneous needs of the customer is purchased by IMPA at a rate determined by the agency on an annual basis. Under the program, the retail customer must sign an interconnection and safety agreement with the local utility and a purchased power agreement with IMPA. As of the date of this report, IMPA, has contracted with 28 customers, totaling 2.4 MW of installed renewable energy systems.

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 for a CHP project to go forward.

Except for 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.

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 100 MW of solar facilities. IMPA members implement the Green Power rate if they desire. Currently, IMPA members have 68 retail customers on the Green Power rate and sell over 1,600 MWh per year under the program.

5.4 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:

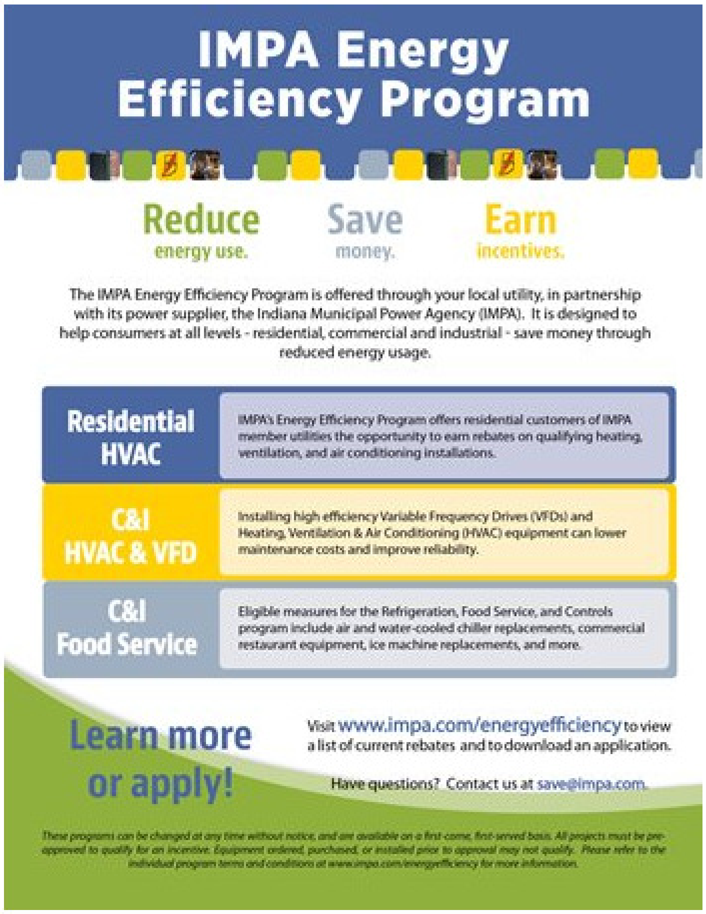
IMPA Energy Efficiency Program

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 5 IMPA Energy Efficiency Program



Source: www.impa.com/energyefficiency

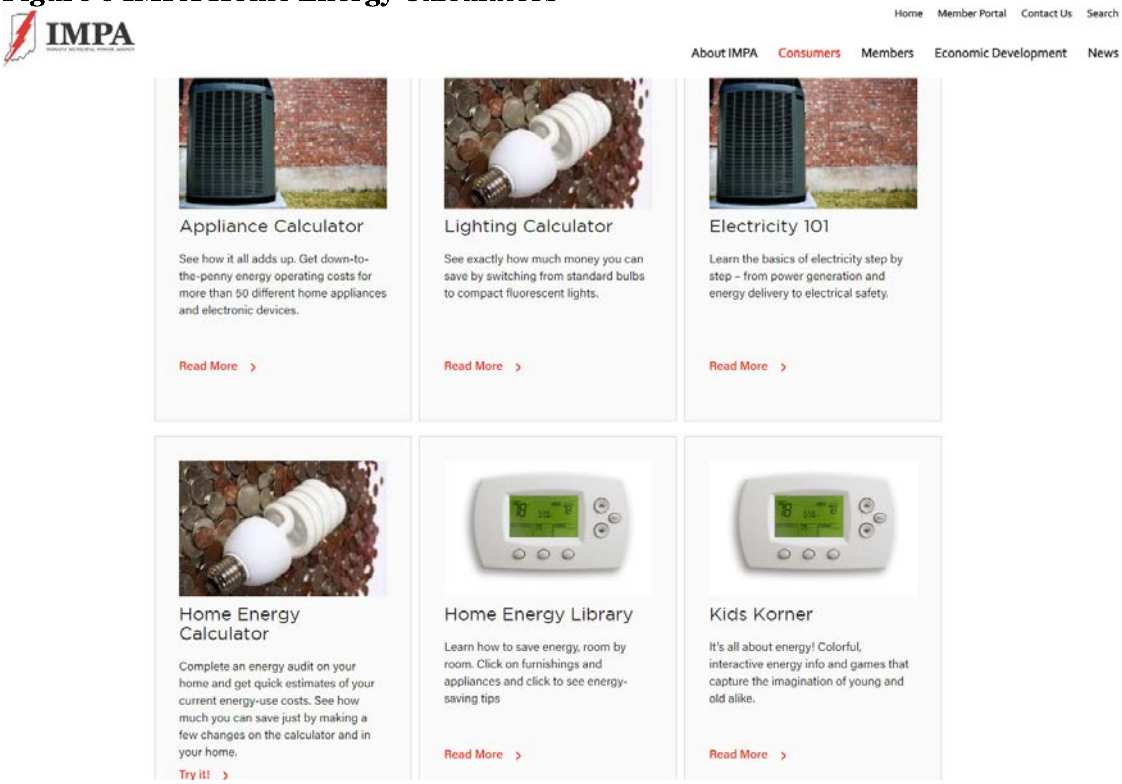
Energy Efficiency and Conservation Education

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 LED light bulbs, LED nightlights with photocell sensors, weather stripping and switch/outlet insulators.

IMPA's website at www.impa.com/energyefficiency includes energy efficiency, conservation and safety information for consumers as well as links to various energy calculators and USDOE information.

Figure 6 IMPA Home Energy Calculators



Source: www.impa.com/energycalculators

Demand Response

On December 10, 2010, IMPA's board approved Demand Response tariffs 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 use. 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 2019, IMPA's energy efficiency programs have generated a cumulative savings of 120,000 MWh and a coincident peak reduction of approximately 13.5 MW.

Table 4 Energy Efficiency Results (2009-2019)

MWh – Annual	2011 and Prior	2012	2013	2014	2015	2016	2017	2018	2019
Residential	214	9,459	15,522	16	22	27	19	9	9
Commercial and Industrial	16,292	22,521	37,155	2,186	2,126	7,492	2,957	3,028	1,160
Annual Total (MWh)	16,506	31,980	52,677	2,202	2,148	7,519	2,976	3,037	1,169
Cumulative Total (MWh)	16,506	48,486	101,163	103,365	105,513	113,032	116,008	119,045	120,214
MW (Non-Coincident)	**2011 and Prior**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Annual Total (MW)	3.414	7.194	11.468	0.633	0.422	1.531	0.647	0.783	0.241
Cumulative Total (MW)	3.414	10.608	22.076	22.709	23.131	24.662	25.309	26.092	26.333
MW (Coincident)	**2011 and Prior**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Annual Total (MW)	0.693	3.907	6.279	0.360	0.188	0.950	0.472	0.470	0.145
Cumulative Total (MW)	0.693	4.600	10.879	11.239	11.427	12.377	12.849	13.319	13.464

5.5 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.

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.

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.

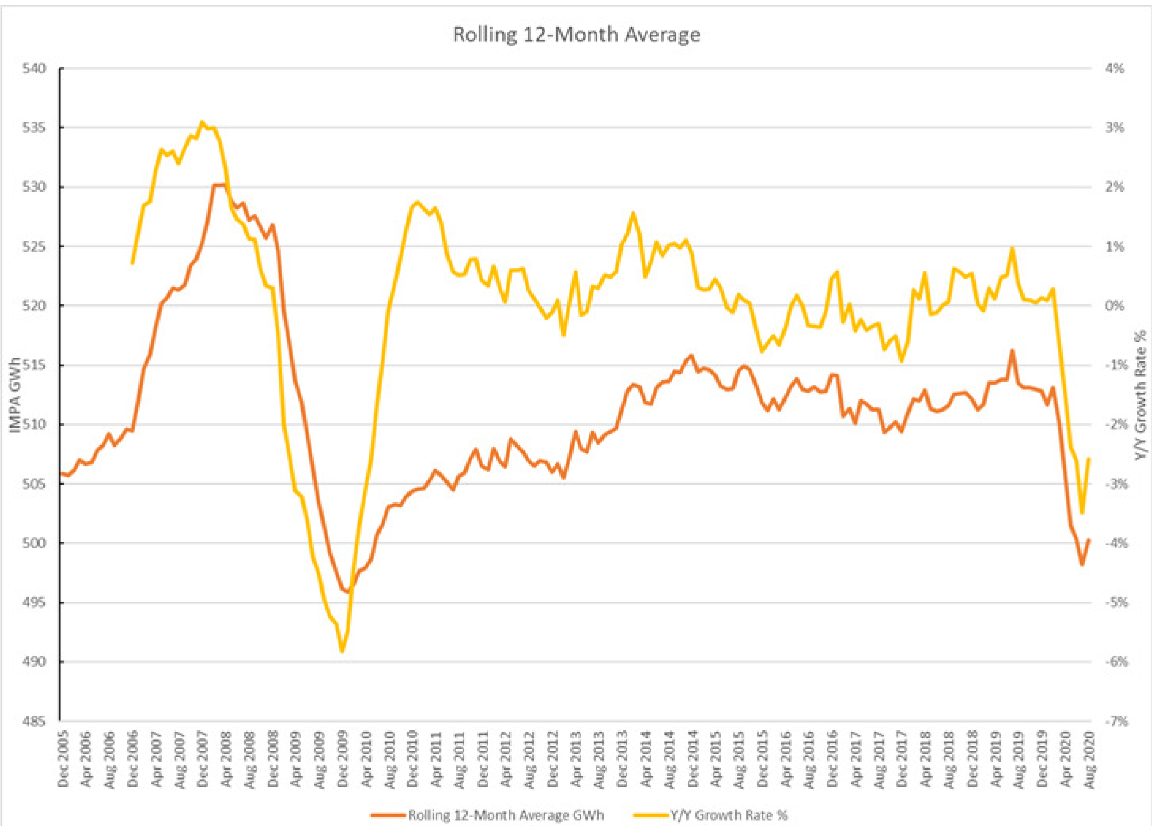
6 LOAD FORECAST

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.

6.1 LOAD FORECAST

As mentioned in the preface, IMPA is experiencing uncertainty related to observed losses in load since the beginning of the COVID-19 pandemic and subsequent stay at home orders. Underpinning this uncertainty is whether IMPA will see permanent demand destruction as businesses within the IMPA service territory weigh their chances of long-term survival. The last time IMPA witnessed declines in -normalized loads was during the great recession, when total loads declined by roughly 6% on a rolling 12-month basis. COVID-19 related losses are currently seeing a roughly 3% decline y/y in growth as shown in the yellow line below.

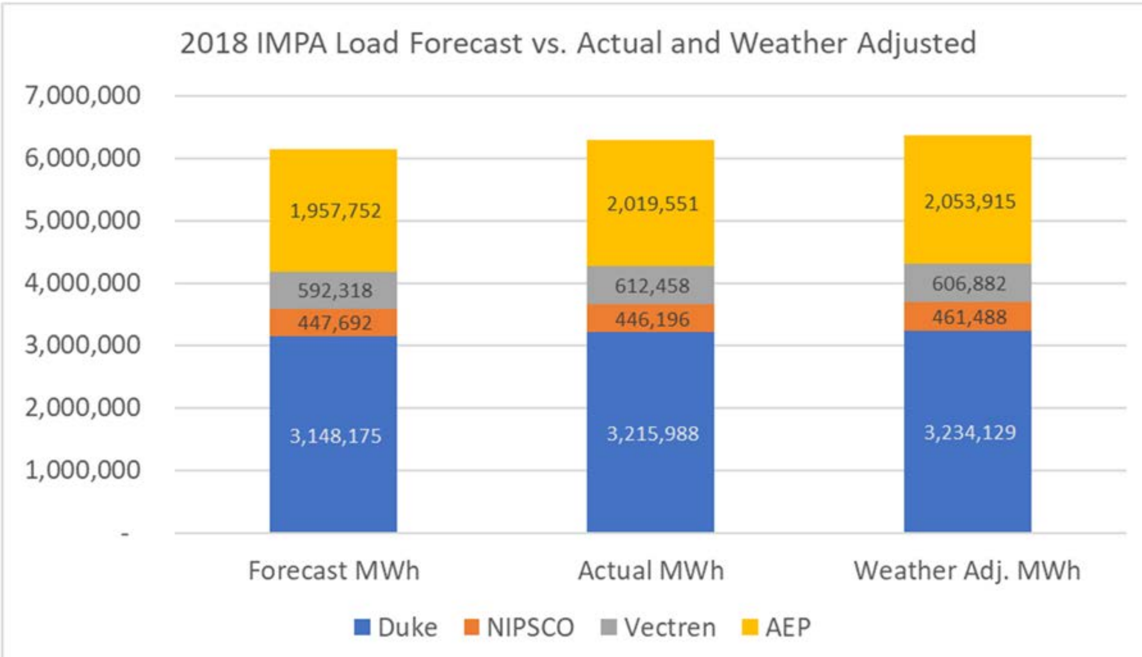
Figure 7 IMPA Weather Adjusted Load Growth



Through June of 2020, the quarterly, year on year growth rate is closer to -10% however and consistent with the ISO/RTO related declines presented in the preface.

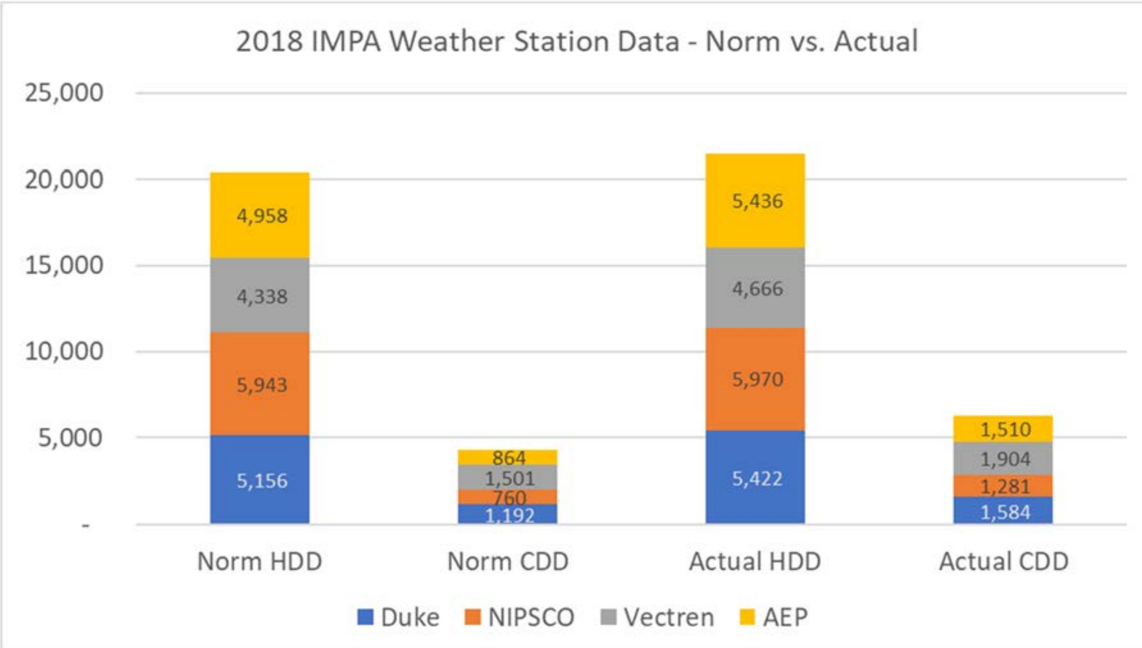
Prior to these downturns, IMPA conducted a load forecast audit for the 2018 and 2019 calendar years. The charts below illustrate the forecast, actual and weather adjusted MWh totals for the main load zones of IMPA and the normalized and actual weather variables.

Figure 8 2018 Forecast Performance



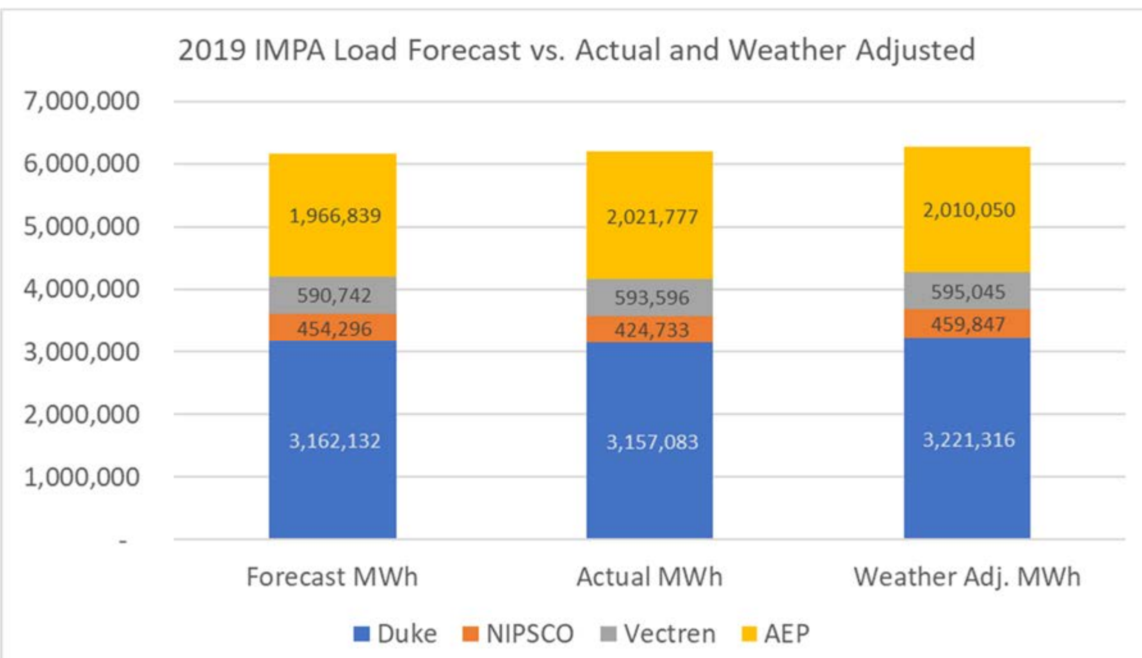
In the figure above, an area breakdown of forecast, actual and weather adjusted MWh values are shown. For 2018, after accounting for actual weather, the load forecast suggests some over-estimation of actual loads given that the year experienced a somewhat hotter summer and colder winter than normal. However, on an annual basis, this error was within 1% of the estimate.

Figure 9 Reference Weather Stations – 2018 Normalized vs. Actual



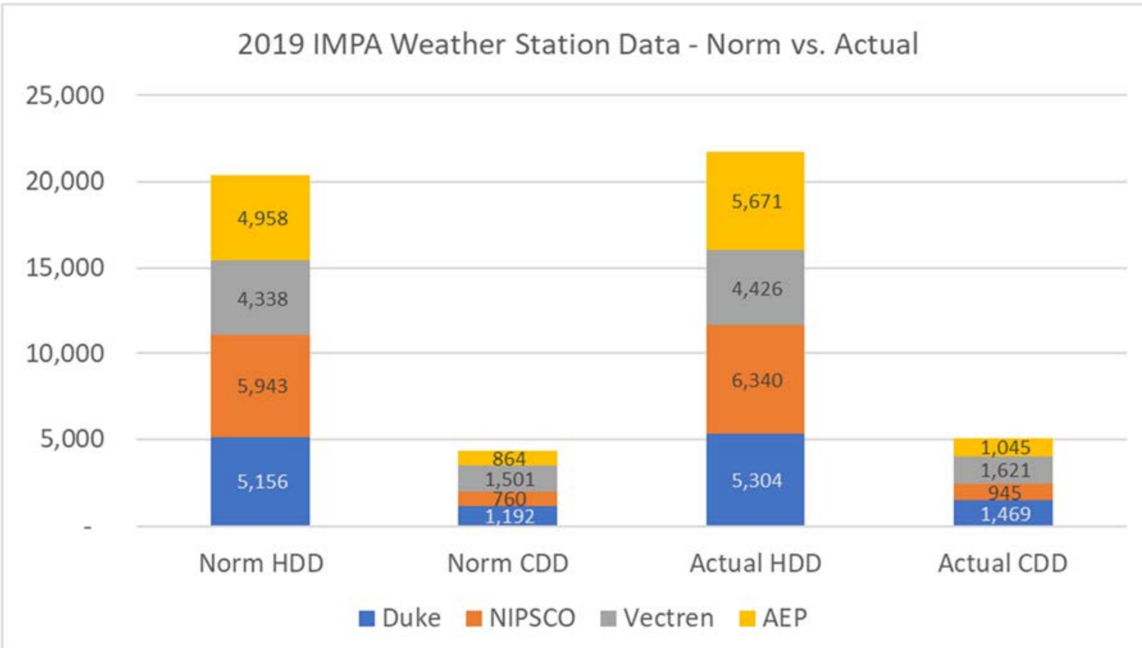
For 2019 a similar process yielded similar error term but with a slight increase when compared to 2018.

Figure 10 2019 Forecast Performance



One standout load would be NIPSCO, which experienced a colder than normal winter (6,340 HDD vs. 5,943 normalized) and a hotter than typical summer (945 CDD vs. 760). In spite of this the actual load for the year in NIPSCO was 424,733 vs. a forecast based on normal weather of 454,296 MWh.

Figure 11 Reference Weather Stations – 2019 Normalized vs. Actual



Some of this apparent overestimate in load was due to the gradual winding down of operations at St. Joseph's College in Rensselaer, IN. Going forward, stripping this load out of historical data or using a simple dummy variable should adequately correct for this gradual wind-down of that particular load.

However, with the above audit and prior to COVID-19, IMPA decided to maintain its model for load forecasting for this IRP, at least until more COVID-19 data is captured.

With that in mind, IMPA transitioned to a unifying model for 4 of its 5 load zones after its last IRP was filed. This involved finding regression variables that satisfactorily explained movements in all of IMPA's major load zones (Duke-IN, NIPSCO, Vectren, AEP). With prior efforts laying the ground work for a unifying regression, the variables chosen were: On and Off Peak Days (as defined by NERC),Heating Degree and Cooling Degree Days for the respective area weather station, a dummy variable for winter/summer peak, energy intensity (btu per dollar of real GDP), and finally real U.S.,GDP in average annual $. The tables below illustrate the regression statistics for each of IMPA's largest load zones.

Table 5 Energy Forecast Variables & Regression Statistics

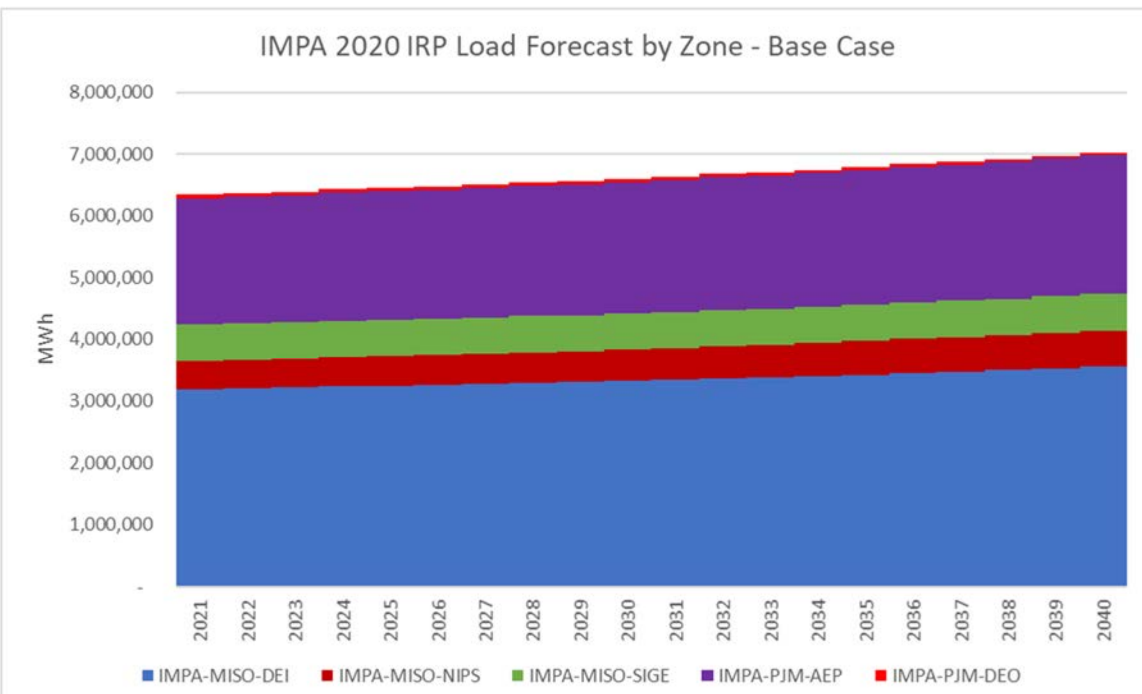
T-Stats & Selected Regression Statistics by Zone									
Area	Peak Days	Off-Peak Days	Relevant Weather Station HDD	Relevant Weather Station CDD	Peak Season Dummy	Energy Intensity (btu/$ of GDP)	Annual Real GDP (average annual $)	Model R^2	Observations
DUK-IN	10.5	9.7	14.6	20.9	5.8	8.1	7.4	0.94	168
NIPSCO	7.3	4.4	3.7	9.9	2.3	4.0	8.3	0.83	168
Vectren	9.0	6.6	4.7	17.1	4.2	9.6	4.4	0.94	168
AEP	8.1	7.1	13.7	13.4	5.7	2.9	3.8	0.87	168
DUK-OH	3.7	3.5	8.0	7.8	4.1	16.5	N/A	0.90	132

IMPA's smallest load zone in DUK-OH, is one zone where the data do not fit as well and so that load gets a similar model but excludes real GDP.

Peak load forecasts are driven by hourly variables and are dependent on daily weather (i.e., wind speeds, temps), but are largely driven by the monthly energy forecast broken into a peak day shape for given peak day weather variables.

The figure below illustrates the IMPA load forecast by area over the 20-year forecast horizon.

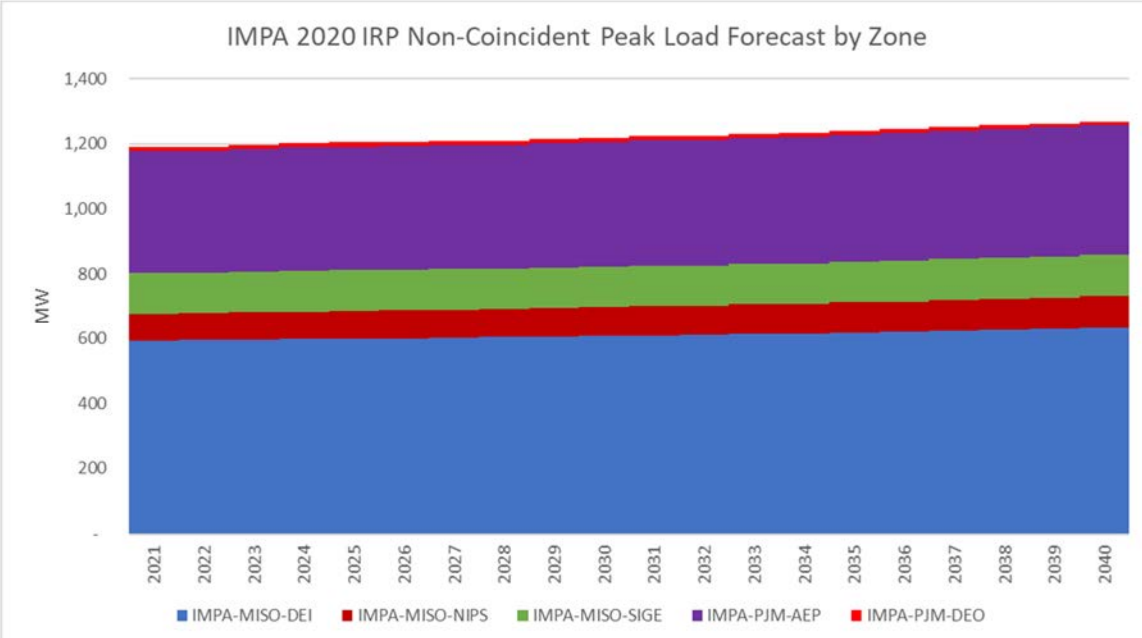
Figure 12– 2020 IRP Energy Forecast by Zone



Companywide this represents a 20-year average annual growth rate of .53%, absent any lasting economic damage from COVID-19.

From a Non-coincident peak standpoint, the graph below illustrates the long-term forecast peaks for each load zone.

Figure 13– 2020 IRP Peak Load Forecast by Zone



Nominally, this represents a .33% increase in forecasted peak loads. Ultimately, IMPA expects fairly low growth in energy and demand over the forecast period. This is consistent with the narrative from the Organization of MISO States annual survey on loads and forecasted resources. These surveys have increasingly captured more uncertainty stemming from resource availability, specifically increased forced outages and increased renewable penetration, rather than uncertainty stemming from load growth within the MISO footprint. [3] While electric vehicle penetration is a potential future source of load growth, IMPA does not see this being a driving factor in member communities at this point in time. Risks to the load forecast are skewed to the downside given the increased penetration of behind the meter generation, increased efficiency, and specific to IMPA, constrained service territory due to changes in state law. The following table illustrates the annual energy and peak demand requirements of IMPA over the next 20 years.

[3] https://cdn.misoenergy.org/20200612%20OMS-MISO%202020%20Results%20Webinar451924.pdf

Table 6 IMPA Total Energy and Peak Demand Forecast

Year	*IMPA Total Energy (GWh)*	*IMPA Peak*
2021	6,338	1,178
2022	6,349	1,179
2023	6,370	1,180
2024	6,394	1,183
2025	6,436	1,189
2026	6,450	1,192
2027	6,474	1,194
2028	6,503	1,196
2029	6,543	1,197
2030	6,561	1,202
2031	6,594	1,207
2032	6,628	1,211
2033	6,680	1,213
2034	6,703	1,216
2035	6,742	1,220
2036	6,785	1,226
2037	6,843	1,232
2038	6,876	1,239
2039	6,923	1,244
2040	6,973	1,250

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6.2 Load Forecast Model Performance

The following figures compare the IMPA peak demand and energy forecasts used in the last 5 IRPs with actual results.

Figure 14 Load Forecast Performance – Peak Demand

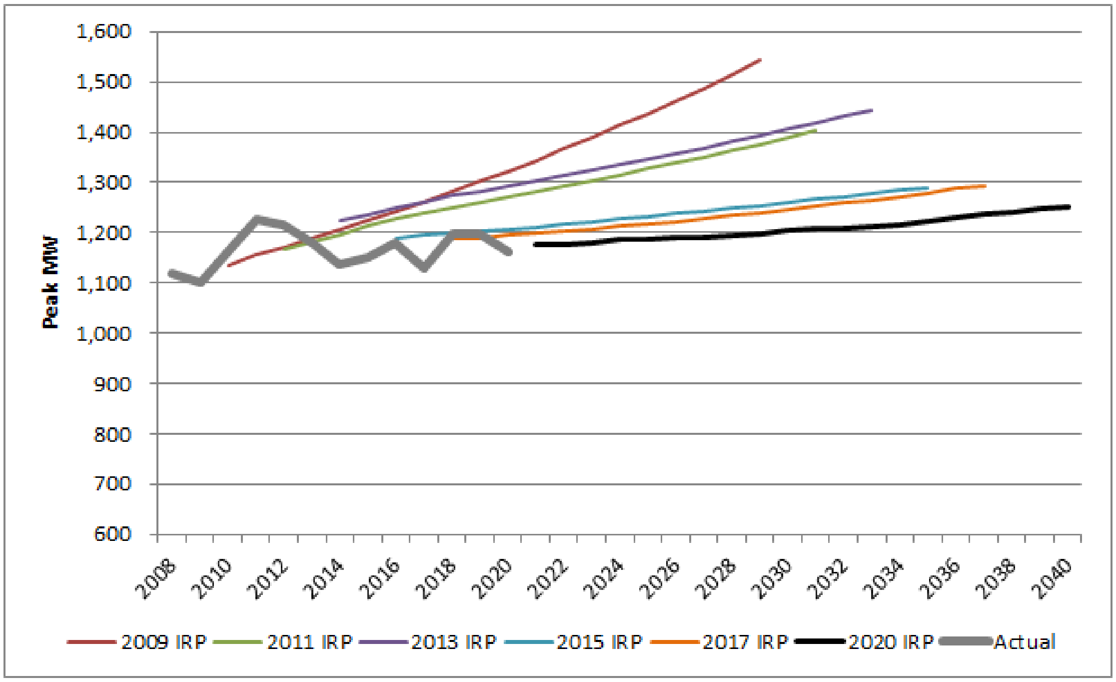
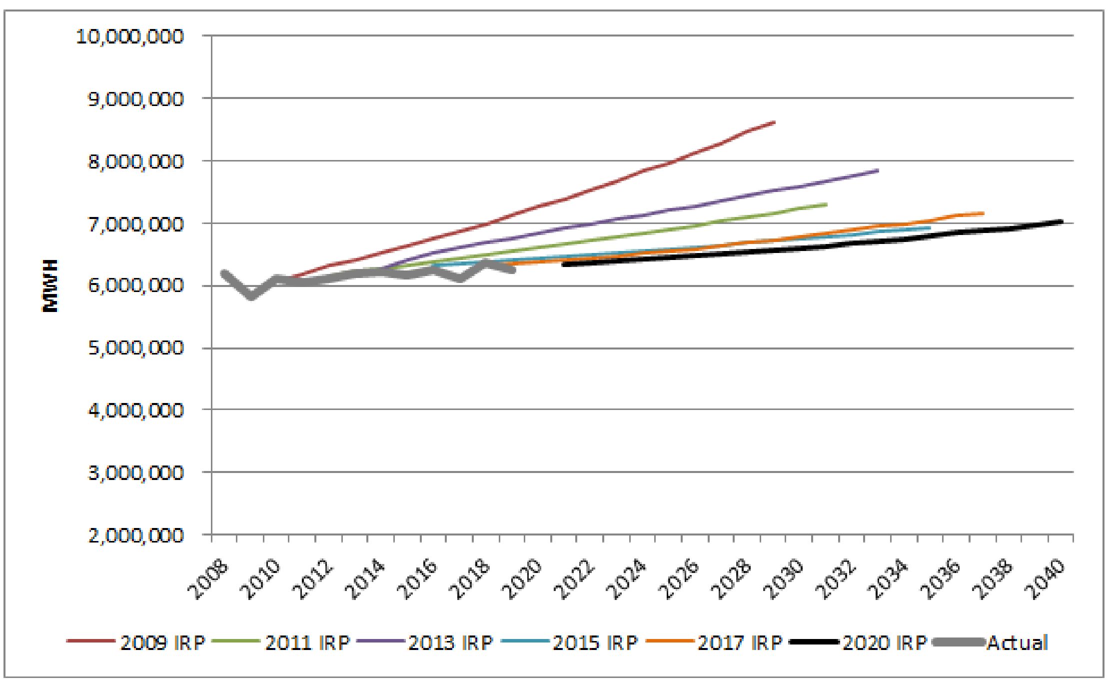


Figure 15 Load Forecast Performance – Energy Requirements



6.3 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 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.

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7 RESOURCE OPTIONS

7.1 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 ownership interests in Gibson 5, Trimble County 1 and 2, Prairie State 1 and 2, seven wholly owned combustion turbines as well as Whitewater Valley Station. IMPA is not aware of any potential upgrades to any of the facilities that could increase their output capability.

At of the time of this report, the majority owner of Gibson #5, DEI, in concert with the minority owners, has decided to retire Gibson #5 in May of 2026. The unit has been removed from the IMPA portfolio effective June 1, 2026.

All other 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 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 units
- Advanced gas-fired combustion turbines
- Aero-derivative combustion turbine
- Coal-fired steam generation
- High efficiency internal combustion 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 2020" from the U.S. Energy Information Administration. Additional information gleaned from IMPA's solar program and renewable RFPs issued by IMPA was used to fine tune the estimates.

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

IMPA's capacity position is such that near-term shortfalls are not commercially feasible to fill with a physical asset. Longer term, IMPA is cautious about the potential for rule changes and price shocks to capacity markets. While IMPA allowed financial power purchases to be made by the model, capacity products were limited to physical assets only. IMPA's financial model balances the capacity positions on an annual basis

Energy Markets

IMPA participates in both the MISO and PJM markets for balancing capacity and short-term energy 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, renewable development and customer owned generation.

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.

7.2 RENEWABLE OPTIONS

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

- Utility Scale Wind
- Utility Scale Photovoltaic Solar

Pricing for all the renewable alternatives was based on the 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 five to six years in addition to the 106.5 MW already developed, totaling approximately 200 MW. Additional renewable energy additions were left up to the expansion and portfolio optimization models to determine.

7.3 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 members' retail customers. The program is a prescriptive rebate system providing incentives for the installation of 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

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

A description of programs and listing of all eligible items and incentives can be viewed at:

https://www.impa.com/energyefficiency

Since 2014, the IMPA energy efficiency program has paid incentives in excess of $500,000 creating a cumulative savings of over 19,000 MWh and 2.6 MW. Going forward, the IMPA energy efficiency program will continue to be IMPA's primary method of offering energy efficiency services to member communities.

8 ENVIRONMENTAL

8.1 COMPLIANCE WITH CURRENT RULES

The following sections describe compliance actions IMPA expects to be taken at its generating facilities in connection with environmental rules.

General

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 July 2020, the EPA finalized revisions to the electronic reporting requirements for the MATS rule. No new monitoring requirements are imposed by this final action. 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 are not be impacted by this rule.

Affordable Clean Energy Rule

In June 2019, the EPA repealed and replaced the Clean Power Plan, which sought to reduce carbon dioxide emissions, by issuing the Affordable Clean Energy (ACE) Rule. The ACE rule is an effort to provide existing coal-fired electric generating units with achievable and realistic standards for reducing greenhouse gas emissions by implementing efficiency improvements. The ACE rule will impact Trimble County, Prairie State, Gibson 5 and Whitewater Valley Station. IMPA does not yet know the full impacts of the rule as the states are still developing their implementation plans which will require certain improvements for existing sources in accordance with the EPA's prescribed Best Systems of Emissions Reduction (BSER). The EPA, or relevant state agency, will employ an "inside-the-fence" framework when determining the required improvements

Effluent Limitation Guidelines

Finalized in September 2015, the Effluent Limitation Guidelines (ELG) Rule established effluent limits on flue gas desulphurization (FGD) wastewater and for bottom ash (BA) transport water. The Final Reconsideration Rule for ELG was published in August 2020. This reconsideration provided revisions to the 2015 rule to include changing the technology basis for treatment, established new compliance dates, revised the Voluntary Incentives Program for FGD wastewater and added subcategories for units that have high wastewater flow, low utilization and those that will cease combustion of coal by 2028. 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. IMPA anticipates that Whitewater Valley Station will meet the criteria for the low utilization subcategory.

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. In July 2020, the EPA proposed to retain, without revision the primary and secondary ozone National Ambient Air Quality Standards. IMPA does not yet know the full impacts of this standard on its generating units.

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

The Cross-State Air Pollution Rule (CSAPR) aims to reduce emissions of SO2 and NOx from electric generating units greater than 25 MW in the eastern half of the United States by controlling 28 upwind states from preventing downwind states from reaching their emission reduction goals for particulate matter (PM2.5) and ozone standards. The proposed Cross State Air Pollution Update Rule (CSAPR Update Rule) would further reduce emissions of NOx from generating units in 23 states, including Indiana, Illinois and Kentucky. On October 15, 2020, the Environmental Protection Agency (EPA) proposed the Revised Cross-State Air Pollution Rule (CSAPR) Update to fully address 21 states' outstanding interstate pollution transport obligations for the 2008 ozone National Ambient Air Quality Standards (NAAQS). IMPA expects that the Agency will have to acquire SO2 and NOx emission allowances in order to comply with CSAPR, but there will be no material impact on IMPA’s generating facilities. The full impacts of the proposed CSAPR Update Rule on IMPA’s generating units are not yet known.

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. In April 2020, The EPA and the Army Corp of Engineers published the Waters Protection Rule in the Federal Register finalizing the definition of "waters of the United States" under the Clean Water Act. This rule became effective June 22, 2020 in all states except Colorado.

Since all of IMPA's units are equipped with cooling towers and/or 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 in a mono-purpose solid waste disposal facility on the site or beneficially reused in the closeout of the surface impoundments at the site. DEI also actively pursues other alternative reuses 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 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 most of the NO_x emissions at Trimble County.

Compliance with the CSAPR SO_2 rule is accomplished through 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 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 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 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 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.

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 like 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 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 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. 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 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 when the chemical tanks are cleaned. A licensed contractor is hired to do this cleaning, remove the waste, and properly dispose the waste. Infrequently, oily waste may be removed from collecting tanks located at the site. This waste is also disposed 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 like 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 using properly licensed vendors.

8.2 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.

9 TRANSMISSION AND DISTRIBUTION

9.1 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 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. 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 based on projections provided by the RTOs.

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10 SOFTWARE OVERVIEW / DATA SOURCES

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

10.1 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.

10.2 MCR-FRST

MCR-FRST by MCR Performance Solutions, LLC is an Excel-based 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 financial inputs to create IMPA's annual revenue requirements.

10.3 RISK ANALYSIS TOOLS

To assess the risk of the various plans, IMPA utilizes a variety of analytical tools and techniques. 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.

10.4 External Data Sources

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

Table 7 External Data Sources

Source Title	Publishing Address
Annual Energy Outlook 2019 & 2020	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
MISO 2020 OMS Survey	Midcontinent ISO (MISO) 701 City Center Drive Carmel, IN 46032
State Utility Forecasting Group-MISO Load Forecast	Mann Hall, Room 160 203 South Martin Jischke Dr. West Lafayette, IN 47907
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-2019	PJM Interconnection 2750 Monroe Boulevard Audubon, PA 19403
NREL Cost Projections for Utility Scale Battery Storage	1503 Denver W. Parkway Golden, CO 80401

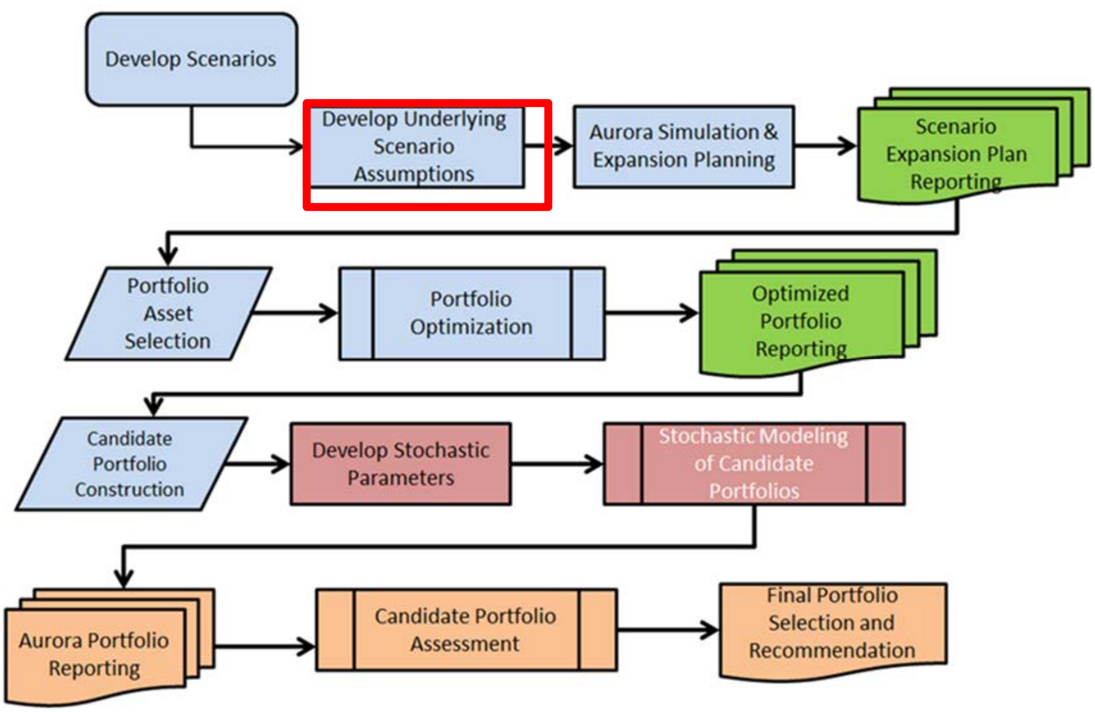
11 BASE CASE

IMPA creates cases, or 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 political, economic, regulatory or technological assumptions.

11.1 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 16 IRP Flowchart



11.2 CARBON POLICY

IMPA's Base Case in the 2020 IRP Cycle represents a modest change in assumptions over the Base Case presented in the 2017-2018 IMPA IRP. With uncertainty being the theme of 2020, IMPA has lowered its expectation for the timing and magnitude of a potential carbon tax. In IMPA's 2017-2018 IRP, IMPA assumed a $20/ton CO2 tax starting in 2026. In this year's IRP, IMPA's Base Case assumption has been lowered to $15/ton and the start has been pushed back to 2029.

A key challenge in arriving at a carbon regime function is that no such regime exists and despite carbon taxation having been a topic of policy change for some time, such a regime has failed to materialize. Nevertheless, utilities continue to aggressively retire coal fired generation in favor of renewable generation despite concerns about intermittency and reliability. In addition to this, utilities continue to publicly state a variety of carbon reduction targets. While certainly some of this is driven by stakeholder pressure and a favorable economic environment for renewables, it may not fully explain utilities long-term commitment to renewables beyond the expiration of the ITC. IMPA believes that utilities are acting in a manner that implies a strong belief that some sort of policy will be enacted that either taxes or limits CO2 emissions.

A large driver then is underlying economic assumptions for the carbon neutral cost of thermal assets relative to renewable assets. With ISO/RTO rules generally more favorable to solar with respect to capacity accreditation, it is no surprise solar projects are dominating their interconnection queues. MISO currently has 36,211 MW of active solar interconnection requests versus 14,261 MW of wind. At a state level this difference is even more apparent with 6,897 MW of solar in Indiana versus 430 MW of wind. [4]

In PJM there are currently just under 80,000 MW of solar or solar paired with storage requesting interconnection compared to just under 14,000 MW of wind. Focusing on Indiana, the difference between these two figures is much narrower than the MISO side of Indiana with 9,000 MW of solar requesting interconnection and 8,200 MW of wind in the queue. [5] PJM's differences are likely due to a combination of slightly different capacity market constructs and various RPS requirements in PJM states. Nevertheless, solar is clearly the technology of choice in the marketplace.

Assuming then that planners are optimizing between solar and traditional thermal resources, the thermal technology of choice is presumed to be a combined cycle, given relatively low fuel cost and lower CO2 footprint when compared to coal. Given that solar currently receives a capacity credit that is 30% lower than a combined cycle, one must overbuild solar to achieve a comparable capacity position. Furthermore, at a 24% net capacity factor, solar built to capacity parity will fail to generate comparable megawatt hours when compared to a combined cycle, requiring additional overbuild.
From a policy standpoint, efforts on CO2 taxes have generally been discussed, but have yet to reach anything resembling a consensus approach, despite a handful of bills being proposed prior to the COVID-19 outbreak. With a CO2 tax being a non-starter during a second potential Trump term and Biden publicly supporting but not outlining what a CO2 tax might look like (and favoring technological innovation and investment), IMPA staff believes any actual carbon tax that materializes will be modest. Politically, given the payroll damage wrought by COVID-19, Democratic policy makers may also not be in a hurry to push any policy that runs the risk of

[4] https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/
[5] https://www.pjm.com/planning/services-requests/interconnection-queues.aspx

increasing voters' electric bills. Consequently, IMPA also believes that the issue of carbon taxation becomes more viable in the out years of the IRP study.

11.3 LOAD FORECASTS – ISO/RTOS

As IMPA models the entire eastern interconnect when running system expansions, a key input into the Aurora model is the system loads used for the MISO and PJM markets. Aurora ships an updated database which includes system load forecasts; however, these figures generally need to be scrubbed to ensure the data is as close to market expectation as possible and reflects the most recent data known. IMPA prefers using forecasts supplied through stakeholder and planning processes whenever possible and as a result uses the Peak Demand Forecast supplied by MISO as part of the annual resource planning auction (PRA). Each year MISO requires participants to submit their annual energy and peak demand forecasts. MISO then aggregates and publishes the coincident peak forecast for each MISO Local Resource Zone (LRZ). In addition, they also publish peaks and growth rates for peak demand over a 5-year period. The table below illustrates the annual peak forecasts published by MISO along with the 5-year growth rate. IMPA assumes the 5-year growth rate holds throughout the duration of the forecast period for each LRZ.

Table 8 Base Case - MISO LRZ Load Forecast Summary

2020/21 PY LRZ Annual Peak Demand Summary

Zone	2020/21PY (MW)	2023/24PY (MW)	2025/26PY (MW)	5-Year AAGR[1]
MISO	124,625	125,308	125,600	0.2%
LRZ-1 (DPC, GRE, MP, MDU, NSP, OTP, SMP)	17,815	18,472	18,707	1.0%
LRZ-2 (ALTE, MGE, UPPC, WEC, WPS, MIUP)	12,728	12,726	12,797	0.1%
LRZ-3 (ALTW, MEC, MPW)	9,558	9,755	9,874	0.7%
LRZ-4 (AMIL, SIPC, CWLP)	9,185	8,926	8,711	-1.0%
LRZ-5 (AMMO, CWLD)	7,830	7,767	7,779	-0.1%
LRZ-6 (BREC, DUK-IN, HE, IPL, NIPSCO, SIGE)	17,585	17,721	17,810	0.3%
LRZ-7 (CONS, DECO)	21,226	20,931	20,693	-0.5%
LRZ-8 (EAI)	7,685	7,838	7,883	0.5%
LRZ-9 (CLECO, EES, LAFA, LAGN, LEPA)	20,885	21,030	21,187	0.3%
LRZ-10 (EMBA, SME)	4,673	4,749	4,798	0.5%

Long term energy forecasts are somewhat more difficult to find for MISO but IMPA relies on zonal energy forecasts by the State Utility Forecasting Group (SUFG). At the time of writing, the most recent zonal forecasts published by SUFG illustrated growth rates that, relative to IMPA's market experience, seem somewhat high. In order to align the SUFG forecast with what is generally closer to growth rates seen in MISO and OMS publications, IMPA uses the SUFG forecast load factor and applies this load factor to the published peak forecast from MISO in order to arrive at a long-term energy forecast. The figure below illustrates the SUFG Peak Demand and Energy forecasts.

Table 9 Base Case - SUFG MISO LRZ Load Forecast

4.1 ANNUAL LRZ ENERGY FORECASTS

Table 47 provides the gross LRZ annual metered load projections (without the EE adjustments) and Table 48 provides the net LRZ annual metered load projections (with the EE adjustments). There are no EE adjustments for LRZ10 because none were indicated from the data provided by MISO.

Table 47: Gross LRZ Energy Forecasts without EE Adjustments (Annual Metered Load in GWh)

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	97,969	64,564	49,045	47,970	38,503	94,677	99,921	37,759	113,210	22,245
2018	99,284	65,456	49,513	48,392	38,546	95,637	101,652	38,193	114,903	22,733
2019	100,852	66,381	50,641	48,507	38,632	96,843	102,263	38,774	115,731	23,078
2020	102,387	67,036	51,364	48,634	38,826	97,849	102,663	39,243	116,721	23,460
2021	103,408	67,625	52,394	48,898	38,990	98,865	103,459	39,664	117,182	23,842
2022	104,231	68,300	53,060	49,174	39,046	99,924	103,520	40,106	117,836	24,246
2023	105,288	68,849	53,559	49,405	39,139	101,107	102,852	40,585	118,955	24,652
2024	106,658	69,386	54,196	49,666	39,264	102,307	103,022	41,044	119,742	25,033
2025	107,882	70,032	55,043	49,863	39,456	103,413	103,705	41,483	120,437	25,368
2026	108,955	70,761	55,820	50,098	39,706	104,534	104,412	41,884	121,062	25,682
2027	109,953	71,541	56,521	50,294	39,950	105,614	105,120	42,263	121,630	25,986
2028	110,986	72,389	57,245	50,522	40,132	106,755	105,798	42,703	122,420	26,304
2029	111,974	73,330	58,074	50,771	40,298	107,914	106,591	43,191	123,319	26,640
2030	112,948	74,183	58,888	51,058	40,430	109,046	107,439	43,670	124,276	27,002
2031	113,800	75,107	59,775	51,282	40,517	110,139	108,198	44,133	125,233	27,345
2032	114,445	75,956	60,610	51,554	40,563	111,205	109,037	44,593	126,228	27,681
2033	115,066	76,766	61,338	51,824	40,574	112,279	109,881	45,071	127,232	28,012
2034	115,804	77,583	62,097	52,081	40,575	113,409	110,581	45,575	128,276	28,365
2035	116,621	78,407	62,958	52,337	40,602	114,544	111,477	46,100	129,348	28,739
2036	117,485	79,288	63,826	52,591	40,642	115,726	112,330	46,656	130,421	29,113
2037	118,312	80,162	64,701	52,877	40,702	116,915	113,131	47,203	131,592	29,488
2038	119,131	81,032	65,575	53,145	40,771	118,109	113,950	47,767	132,728	29,859
Compound Annual Growth Rates (%)										
2019-2023	1.08	0.92	1.41	0.46	0.33	1.08	0.14	1.15	0.69	1.66
2019-2028	1.07	0.97	1.37	0.45	0.42	1.09	0.38	1.08	0.63	1.46
2019-2038	0.88	1.06	1.37	0.48	0.28	1.05	0.57	1.10	0.72	1.37

Table 10 Base Case - SUFG MISO LRZ Peak Load Forecast

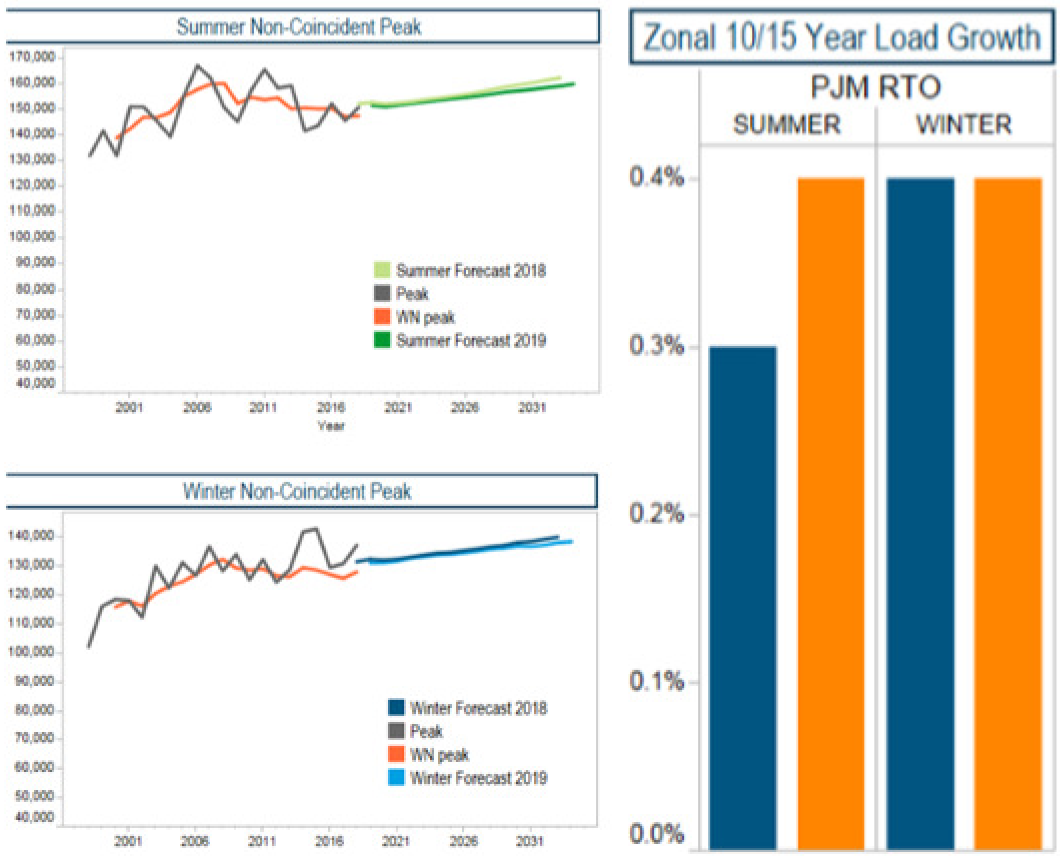
Table 49: Summer Non-Coincident Peak Demand without EE Adjustments (Metered Load in MW)

Year	LRZ1	LRZ2	LRZ3	LRZ4	LRZ5	LRZ6	LRZ7	LRZ8	LRZ9	LRZ10
2017	17,506	12,228	9,294	9,395	7,841	16,414	20,351	7,726	20,564	4,642
2018	17,741	12,397	9,383	9,477	7,850	16,580	20,704	7,815	20,872	4,743
2019	18,021	12,572	9,597	9,500	7,868	16,789	20,828	7,933	21,022	4,815
2020	18,295	12,696	9,734	9,525	7,907	16,964	20,910	8,029	21,202	4,895
2021	18,478	12,808	9,929	9,576	7,941	17,140	21,072	8,115	21,286	4,975
2022	18,625	12,936	10,055	9,630	7,952	17,323	21,084	8,206	21,405	5,059
2023	18,814	13,040	10,150	9,676	7,971	17,529	20,948	8,304	21,608	5,144
2024	19,059	13,141	10,271	9,727	7,997	17,737	20,983	8,398	21,751	5,223
2025	19,277	13,264	10,431	9,765	8,036	17,928	21,122	8,488	21,877	5,293
2026	19,469	13,402	10,578	9,811	8,086	18,123	21,266	8,570	21,991	5,359
2027	19,647	13,549	10,711	9,850	8,136	18,310	21,410	8,647	22,094	5,422
2028	19,832	13,710	10,848	9,894	8,173	18,508	21,548	8,737	22,237	5,489
2029	20,008	13,888	11,006	9,943	8,207	18,709	21,710	8,837	22,401	5,559
2030	20,183	14,050	11,160	9,999	8,234	18,905	21,883	8,935	22,575	5,634
2031	20,335	14,225	11,328	10,043	8,252	19,094	22,037	9,030	22,748	5,706
2032	20,450	14,386	11,486	10,097	8,261	19,279	22,208	9,124	22,929	5,776
2033	20,561	14,539	11,624	10,149	8,263	19,466	22,380	9,222	23,112	5,845
2034	20,693	14,694	11,768	10,200	8,263	19,661	22,523	9,325	23,301	5,919
2035	20,839	14,850	11,931	10,250	8,269	19,858	22,705	9,432	23,496	5,997
2036	20,993	15,017	12,096	10,300	8,277	20,063	22,879	9,546	23,691	6,075
2037	21,141	15,182	12,262	10,356	8,289	20,269	23,042	9,658	23,904	6,153
2038	21,287	15,347	12,427	10,408	8,303	20,476	23,209	9,773	24,110	6,230
Compound Annual Growth Rates (%)										
2019-2023	1.08	0.92	1.41	0.46	0.33	1.08	0.14	1.15	0.69	1.66
2019-2028	1.07	0.97	1.37	0.45	0.42	1.09	0.38	1.08	0.63	1.46
2019-2038	0.88	1.06	1.37	0.48	0.28	1.05	0.57	1.10	0.72	1.37

Modeling the eastern interconnect also requires up-to-date load forecasts for the PJM RTO, particularly as IMPA has roughly 1/3 of its total load in PJM. In the case of PJM however, the latest Aurora database contained an update to include the 2019 PJM Load Forecast Report. Similar to MISO, the Pre-COVID forecasted demand and energy numbers reflect very low growth for loads over the intermediate to long term with 10- and 15-year growth rates coming in under .5%/yr. [6]

[6] PJM Load Forecast Update, January 2019; PJM Resource Adequacy Planning Department

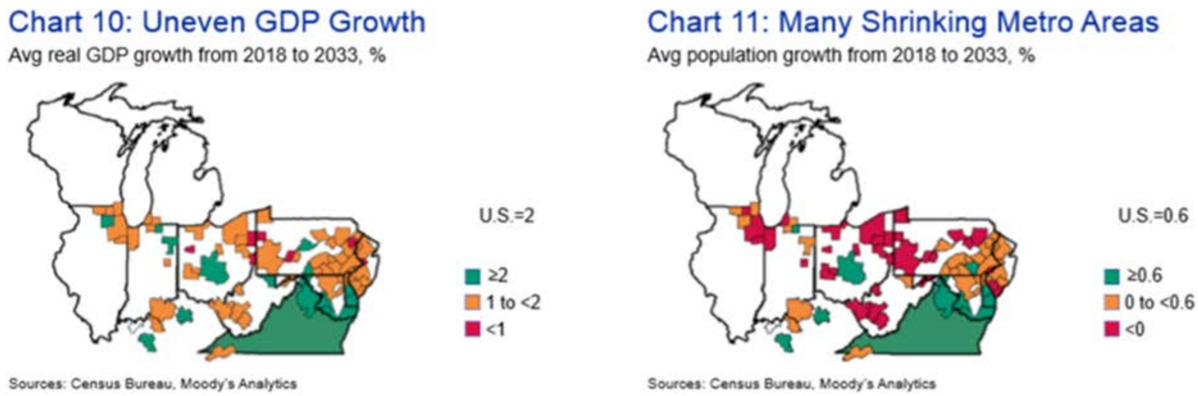
Figure 17 Base Case - PJM Regional Energy Forecast



In contrast with MISO, PJM's forecast is internally generated and more "top-down" when compared to MISO. That is, PJM looks at fundamental and structural factors within the zones in their footprint and generates a corresponding forecast whereas MISO largely relies on stakeholder input to arrive at load forecasts. Broadly speaking, PJM sees long-term load growth as lagging broader economic growth in the United States due to factors stemming from low birth rates combined with an accelerated rate of deaths in an aging population. More relevant to IMPA are the regional forecasts within the broader RTO. IMPA's PJM load resides in the western edge of PJM in the AEP zone. PJM's annual growth rate for the AEP zone is slightly higher than the broader RTO growth rate shown above. However, AEP's load zone within PJM encompasses a region from southwestern Michigan, northeastern Indiana, through Ohio, West Virginia and into western Virginia. Within PJM's forecast commentary they note Virginia load growth will tend to "outperform the service territory and U.S. for GDP growth thanks to a highly educated labor force, productivity growth, and positive demographic trends[7]." The AEP load zone however is a tale of two growth stories with the east being a tale of growth and the western areas experiencing lower growth driven by lower population growth.

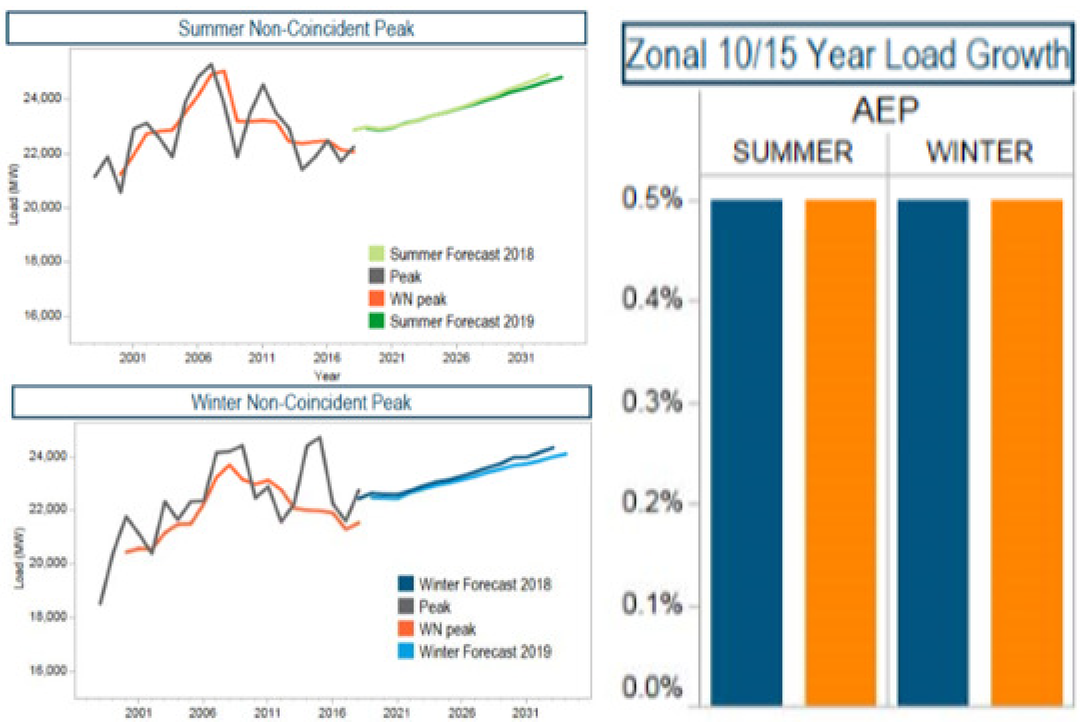
[7] Ibid.

Figure 18 Base Case - PJM Load Forecast Drivers



The table below is PJM's illustration of forecast load growth for the AEP zone.

Figure 19 Base Case - PJM AEP Zone Forecast



Generally speaking the PJM expectation is for slightly higher annual growth within the AEP zone vs. what IMPA believes its PJM load growth will achieve.

11.4 GENERATION AND TECHNOLOGY COSTS

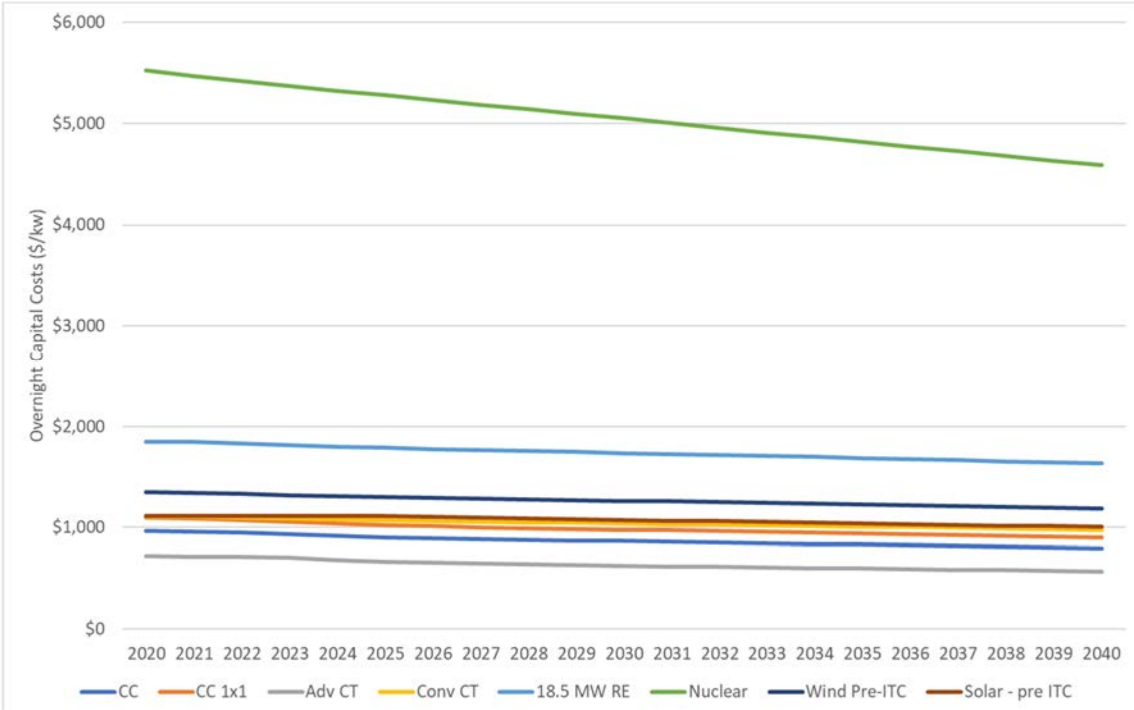
When allowing Aurora to run its resource expansion module, one of the key inputs is the selection of allowable technology, its estimated cost of overnight construction, and any associated carrying cost of capital. As a starting point, IMPA references the most recent EIA Annual Energy Outlook cost estimates of new generation. From there IMPA staff make adjustments to the EIA figures based on their interactions with developers in relevant technology segments. For example, IMPA has been in regular contact with a number of renewable developers since the last IRP as part of its regular planning processes. From these conversations, IMPA has determined that the cost of unsubsidized solar as published by the EIA is somewhat high. With some technologies, however, IMPA has not had interaction with developers and as a result relies primarily on the EIA figures and industry publications (i.e., Gas Turbine World) for costs.

The table below illustrates the capital costs as published in the EIA Annual Energy Outlook and IMPA's assumed cost as modeled.

Table 11 Generation Costs ($/kw) For New Generation Technology

Assumes 2022 order year		
Tech	***IMPA Assumption - 2019 $***	***NEW AEO Cost - 2019 $***
CC 2x1	$952	$954
CC 1x1	$1,076	$1,079
Adv CT	$710	$710
Conv CT	$1,098	$1,170
18.5 MW RE	$1,833	$1,802
Nuclear	$5,418	$6,016
Wind Pre-PTC	$1,330	$1,319
Solar - pre ITC	$1,110	$1,331

Figure 20 New Generation – Overnight Costs ($/kW) - Unsubsidized

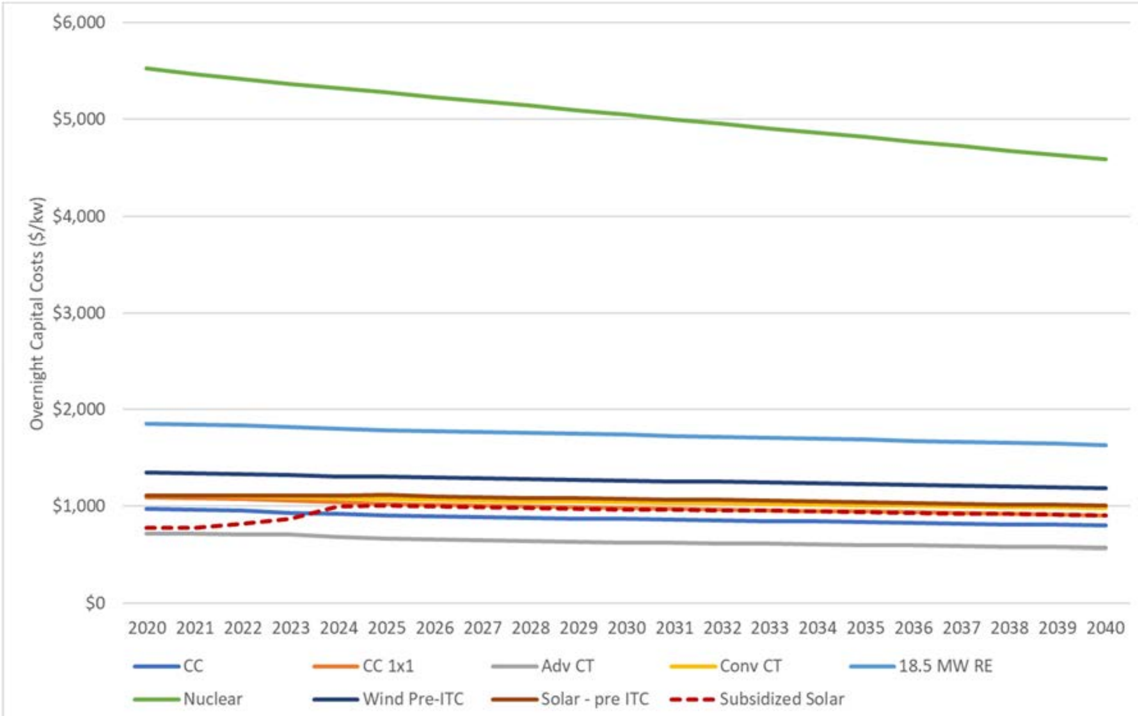


On the surface the lowest cost generation is expected to be Advanced Combustion Turbines, ignoring subsidies, fuel cost assumptions, emissions costs, and carbon policy.

As noted previously, IMPA estimates that on an unsubsidized basis there is some need for a carbon tax or penalty for renewables to be competitive with carbon intensive generation due to the capacity credit and energy profile of those assets. However, the ITC changes this dynamic somewhat in the near term. While the solar ITC is set to phase down to 10% after 2021, the IRS issued guidance in 2018 that clarified the requirements to meet the continuing construction requirement. In this guidance the IRS stated that companies can either use a start of physical work standard or a 5% safe harbor standard. This effectively gives solar developers a longer "runway" to qualify for higher ITC amounts than previously anticipated yet establishes a firm 10% ITC for projects in service after 2023. IMPA assumes projects coming online in 2022 will qualify for a 26% ITC and projects coming online in 2023 will qualify for the 22% ITC. For all solar beyond a 2023 COD, IMPA assumes a flat 10% ITC.

In the short run, this makes subsidized solar cheaper than a 2x1 CC for projects installed in 2022 and 2023. After 2023, 2x1 CCs are expected to be a cheaper source of new generation than solar absent a CO_2 tax. The chart below adds the impact of the ITC to overnight capital costs to solar and impacts to the overall competitiveness of solar over the course of the study.

Figure 21 New Generation – Overnight Costs ($/kW) - Subsidized



For the duration of the study and assuming the ITC remains in place at 10% of eligible costs, solar is expected to remain slightly more expensive than 2x1 CCs and Advanced CTs. From an expansion planning standpoint this would translate into an aggressive build out of solar until roughly 2023 with CC's and CTs being the preferred technology thereafter.

Energy Efficiency

Energy Efficiency programs were modeled as a selectable resource that were effectively load decrements at incrementally higher costs. Specifically, the initial block of energy efficiency was modeled in quarter MW increments, with the initial 1/4 being modeled at IMPA's current cost of implementation. This approximated the forward price for wholesale power. Additional increments were "priced" on an increasing basis reflecting the loss of "low hanging fruit" and increasingly difficult to find efficiencies as end-users replace lighting and appliances.

Storage

Storage assets were strongly considered. However, after an internal review of comparative economics and business use cases undertaken in the Fall/Winter of 2019/2020, IMPA opted not to consider storage assets for this IRP. As much as storage projects grab headlines, IMPA's research found that the economics are highly dependent on the use case made. This is driven largely by technology selection for a given deployment strategy. Despite a rapidly evolving landscape and declining technology costs, storage projects tend to be high custom to the solution required, leading to widely variable costs. The table below illustrates IMPA's estimated CAPEX for battery storage across a variety of applications.

Table 12 Storage Capital Costs ($/kW)

Sandia/DOE/EPRI Storage Cost Survey - Adjusted for Cost Equipment Cost Declines via Bloomberg New Energy Finance											
Source Pricing	Specified Use	Project Size (MW)	Cycles/ Year	Discharge Hours	Equipment Cost - $/kw	Installation Cost - $/kw	Contingency Cost - $/kw	Installed Cost - $/kw	Total Cost - $	O&M - $/kw-yr	Notes
Sandia/DOE/ EPRI	Frequency Response	2	5000	0.25	$ 606	$ 154	$ 65	$ 825	$ 1,650,416	$ 7	NRECA/CFC/CoBank 2019 Report
Sandia/DOE/ EPRI	Frequency Response	1	5000	0.25	$ 584	$ 185	$ 59	$ 829	$ 828,535	$ 9	NRECA/CFC/CoBank 2019 Report
Sandia/DOE/ EPRI	Frequency Response	2	15000	0.25	$ 697	$ 135	$ 69	$ 901	$ 1,802,377	$ 7	NRECA/CFC/CoBank 2019 Report
Sandia/DOE/ EPRI	Transmission & Distribution	1	365	3	$ 2,440	$ 230	$ 241	$ 2,911	$ 2,910,780	$ 9	NRECA/CFC/CoBank 2019 Report
Sandia/DOE/ EPRI	Transmission & Distribution	10	365	2 to 3	$ 2,607	$ 207	$ 264	$ 3,079	$30,785,584	$ 6	NRECA/CFC/CoBank 2019 Report
Sandia/DOE/ EPRI	Transmission & Distribution	3	365	1	$ 944	$ 112	$ 88	$ 1,145	$ 3,434,624	$ 6	NRECA/CFC/CoBank 2019 Report

To arrive at these cost estimates, IMPA staff applied cost decline observations from McKinsey/Bloomberg New Energy finance to a 2011 Sandia/DOE/EPRI storage cost survey. [8]

It is important to note that, with the original survey data being somewhat dated, there may be some offer uncertainty baked into the quoted prices for the larger quoted systems in T&D shown here. The quotes may also reflect respondent contingencies unique to the Sandia RFP. In discussions with storage developers, IMPA staff have seen benefits of scale of about 10% for a tenfold increase in capacity. The common theme in these conversations, however, has been that every storage project is different and costs depending on application can and will vary. For now, however, IMPA assumes the Sandia information above, adjusted for price declines, represents a reasonable planning quote for projects.

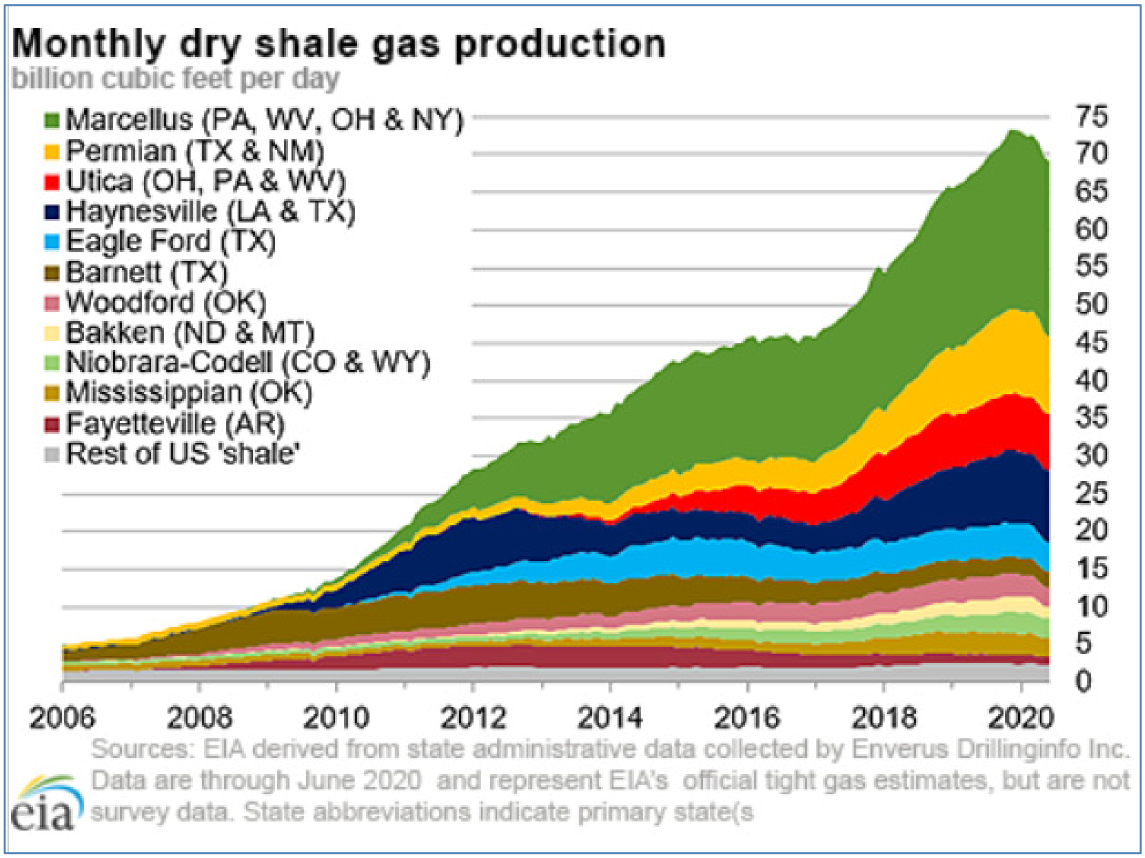
However, given the installed cost per kw and the lack of clear business case for IMPA to deploy storage assets at this time, more conventional technologies were considered more financially responsible.

[8] Bloomberg New Energy Finance, "A Behind the Scenes Take on Lithium-ion Battery Prices", March 2019

11.5 Fuels

IMPA relies heavily on forward market prices to supply the planning process with an unbiased forecast of future expected spot prices for fuels, where possible. Given announced coal retirements to date and capital costs noted above, IMPA expects the primary feedstock for future dispatchable generation to be natural gas. Natural gas continues to be well supplied domestically with shale gas production near all-time highs despite COVID-19 impacts. [9]

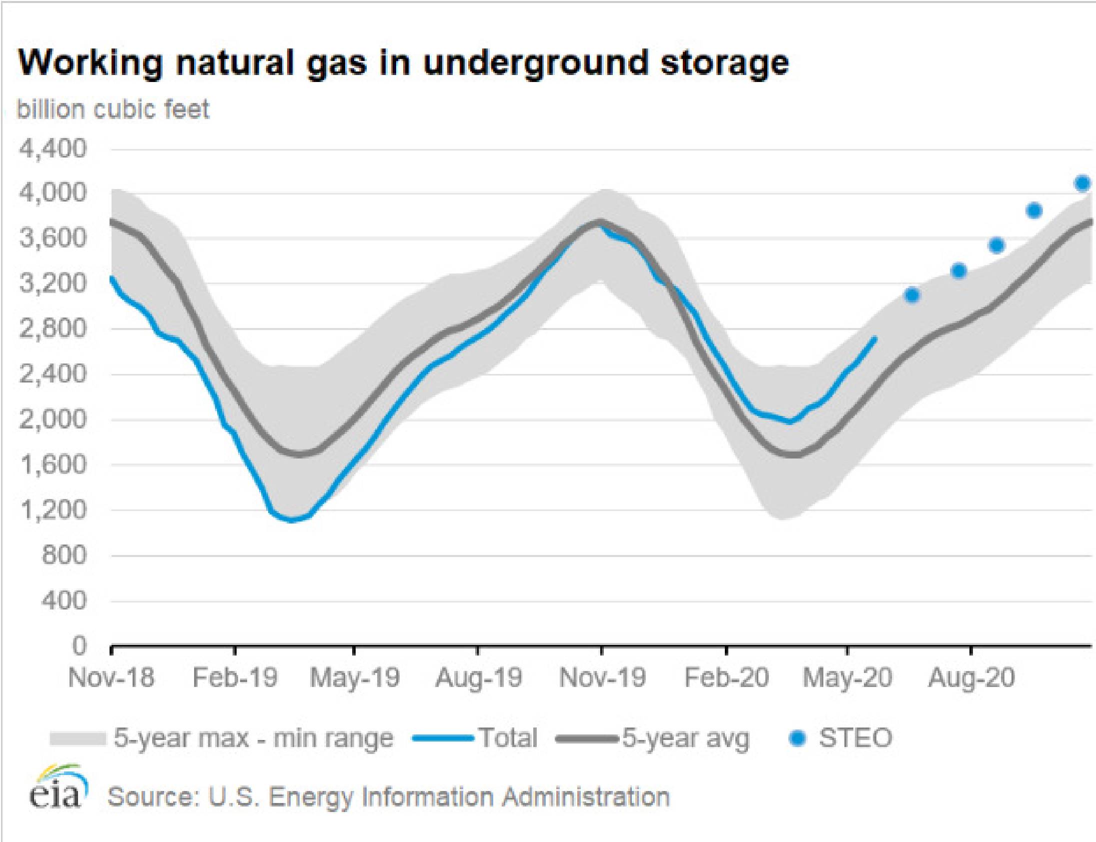
Figure 22 Shale Production



Also supporting low natural gas prices for the foreseeable future are natural gas supplies in storage that are near the 5-year high and projected to trend above the 5-year average in the latter part of 2020.

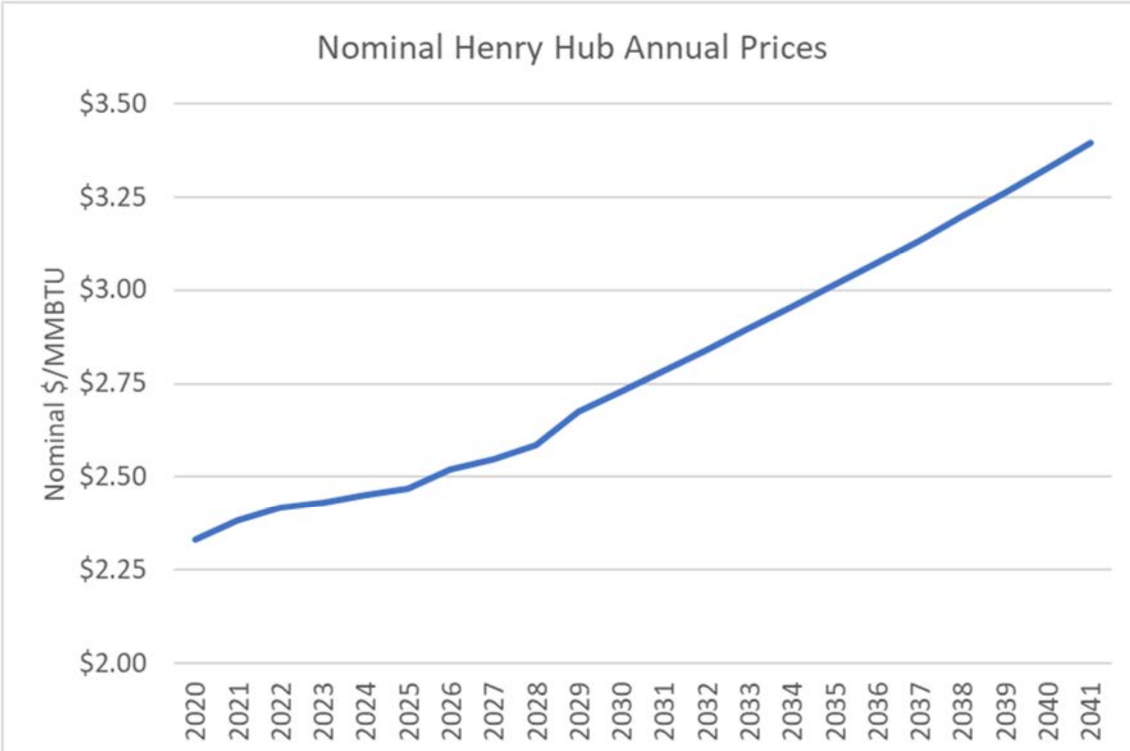
[9] https://www.eia.gov/naturalgas/weekly/#tabs-storage-1

Figure 23 Natural Gas Storage



The chart below illustrates the forward curve for Henry Hub Natural Gas in nominal dollars per MMBTU from data supplied by S&P Global Market Intelligence.

Figure 24 Base Case - Henry Hub Natural Gas Prices

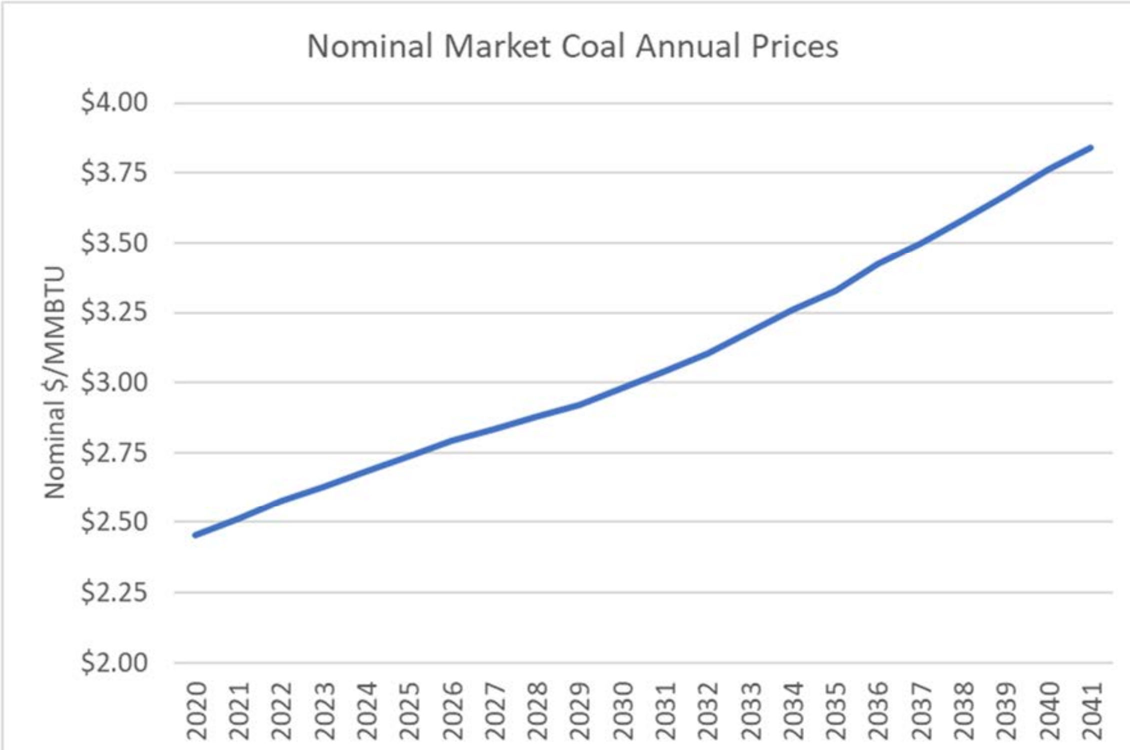


Notably the quoted market is published through 2030 at which point IMPA uses the year over year change in the forward curve to build out the forward curve through the study period.

Long-term price forecasting for coal is somewhat more problematic due to the confidential nature of many coal supply agreements and a relative lack of liquidity in forward markets. In addition, because Aurora is a market model, using budget coal forecasts for IMPA's own coal units may inadvertently introduce a bias to those units by making them either too competitive within the market or not competitive enough. As a result, IMPA first creates a market-based coal forecast.

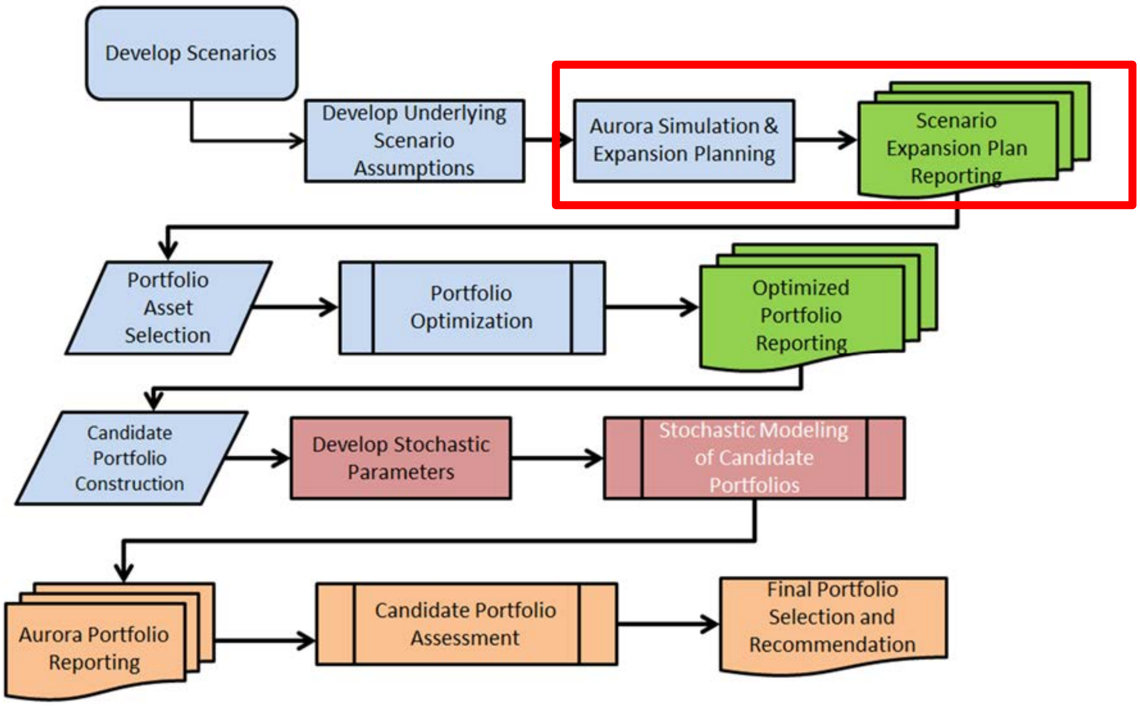
To do this, IMPA combines observable forward coal prices, also supplied by S&P Global Market Intelligence, with coal market forecasts from JD Energy, Inc., across varying heat contents and fuel basins. That price is then applied to coal units that are outside IMPA's direct control/observation. The model is then run zonally and outputs are compared to historical run data in order to determine if IMPA's budgeted costs can be used without introducing bias. For the purposes of this IRP, it was determined that a blend of historic and budgeted coal costs for IMPA-owned units was appropriate in order to maintain accurate and known costs while not introducing any perceived bias into the model.

Figure 25 Base Case - Coal Prices



11.6 Market Expansion

From a process flow standpoint, running Aurora's Long-Term Capacity Expansion Module is a critical first step. Sections prior to this have been devoted to IMPA's underlying assumptions for this modeling effort. This section outlines the resulting optimal capacity expansion for the MISO and PJM markets.



Using the key assumptions above, along with a host of other assumptions, the market expansion module of Aurora is utilized to determine the lowest cost resource mix for the various market areas modeled. As outlined above, the underlying assumptions for fuels, capital costs, subsidies and carbon policy would likely favor a build that was solar heavy in the near term while shifting to natural gas fired generation in later years. Prior to allowing Aurora to determine which units were retired, however, IMPA staff updated the Aurora delivered database with known retirements. The table below illustrates some of the announced planned retirements that were assumed and specific to Indiana.

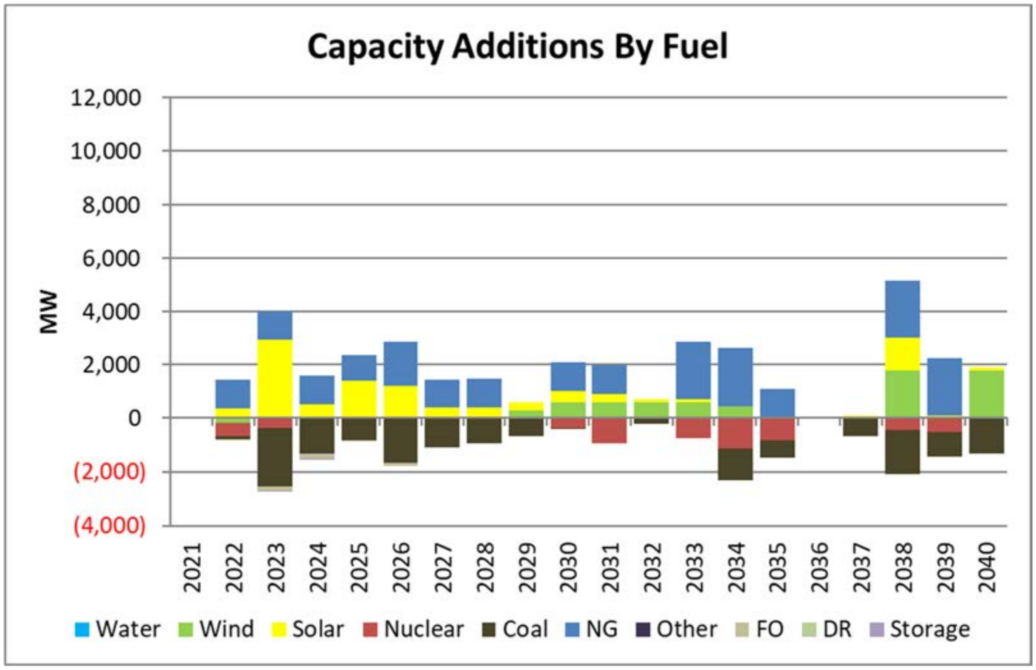
Table 13 MISO Indiana Generator Retirements

Utility	Unit Name	Capacity	Fuel	Retirement Date
Vectren	Northeast (IN) (1)	10.7	Natural Gas	4/1/2021
Vectren	Northeast (IN) (2)	11.5	Natural Gas	4/1/2021
Duke Indiana	R Gallagher (2)	150	Coal	12/31/2022
Duke Indiana	R Gallagher (4)	150	Coal	12/31/2022
IP&L	AES Petersburg (ST1)	281.6	Coal	5/13/2023
IP&L	AES Petersburg (ST2)	523.3	Coal	5/13/2023
Hoosier Energy	Merom (1)	540	Coal	5/31/2023
Hoosier Energy	Merom (2)	540	Coal	5/31/2023
Vectren	A B Brown (1)	265.2	Coal	12/1/2023
Vectren	A B Brown (2)	265.2	Coal	12/1/2023
Vectren	F B Culley (2)	103.7	Coal	12/1/2024
Vectren	Broadway (IN) (2)	88.8	Natural Gas	12/1/2025
Duke Indiana	Gibson (5)	667.9	Coal	5/31/2026
NIPSCO	R M Schahfer (14)	540	Coal	5/31/2026
NIPSCO	R M Schahfer (15)	556.4	Coal	5/31/2026
NIPSCO	R M Schahfer (17)	423.5	Coal	5/31/2026
NIPSCO	R M Schahfer (18)	423.5	Coal	5/31/2026
Duke Indiana	Cayuga (1)	531	Coal	5/31/2028
Duke Indiana	Cayuga (2)	531	Coal	5/31/2028
NIPSCO	Michigan City	540	Coal	5/31/2028
Duke Indiana	Gibson (3)	667.9	Coal	5/31/2034
Duke Indiana	Gibson (4)	667.9	Coal	5/31/2034
Duke Indiana	Gibson (1)	667.9	Coal	5/31/2038
Duke Indiana	Gibson (2)	667.9	Coal	5/31/2038

PJM Indiana related retirements include AEP's Rockport 1 in 2028 and Donald C. Cook Units 1 & 2 in 2034 and 2037.

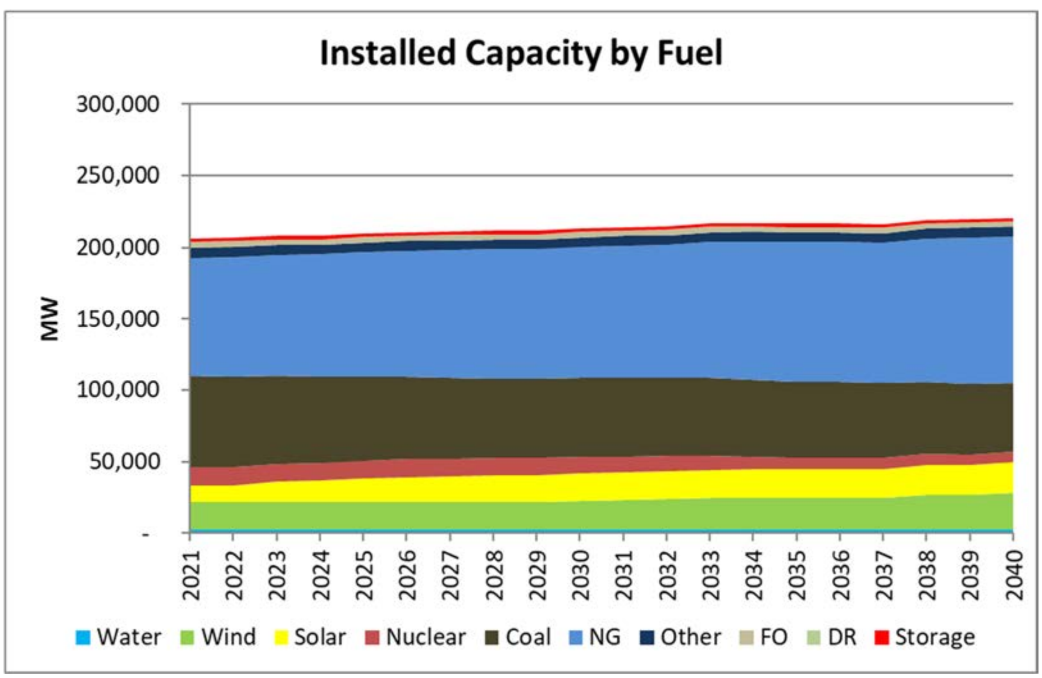
The following charts illustrate the resulting build plan for the MISO market.

Figure 26 Base Case - MISO Net Capacity Additions by Fuel



Within the MISO market, solar and natural gas fired assets are expected to make up a bulk of new capacity additions in the early years, while in out years wind becomes more economically competitive, primarily as a source of energy, rather than capacity.

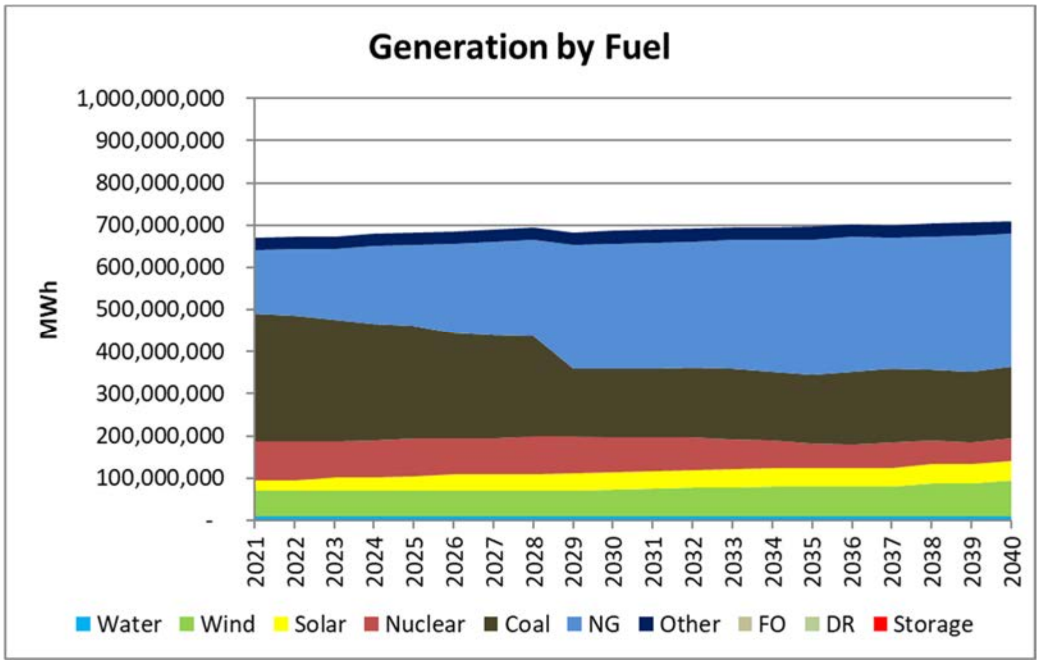
Figure 27 Base Case - MISO Installed Capacity by Fuel



In terms of overall installed capacity, solar is clearly the fastest growing technology under the IMPA Base Case while Nuclear and Coal see gradual declines. It is worth noting that despite a CO2 tax modeled in 2029, it is insufficient to trigger any mass retirements of coal in 2029.

However, as shown in the next chart, coal is less committed for energy in 2029 and beyond, suggesting there is some value in retaining the units as capacity resources, while gas (CC) and renewables do the "heavy lifting" of supplying a much higher percentage of energy to the market.

Figure 28 Base Case - MISO Generation by Fuel

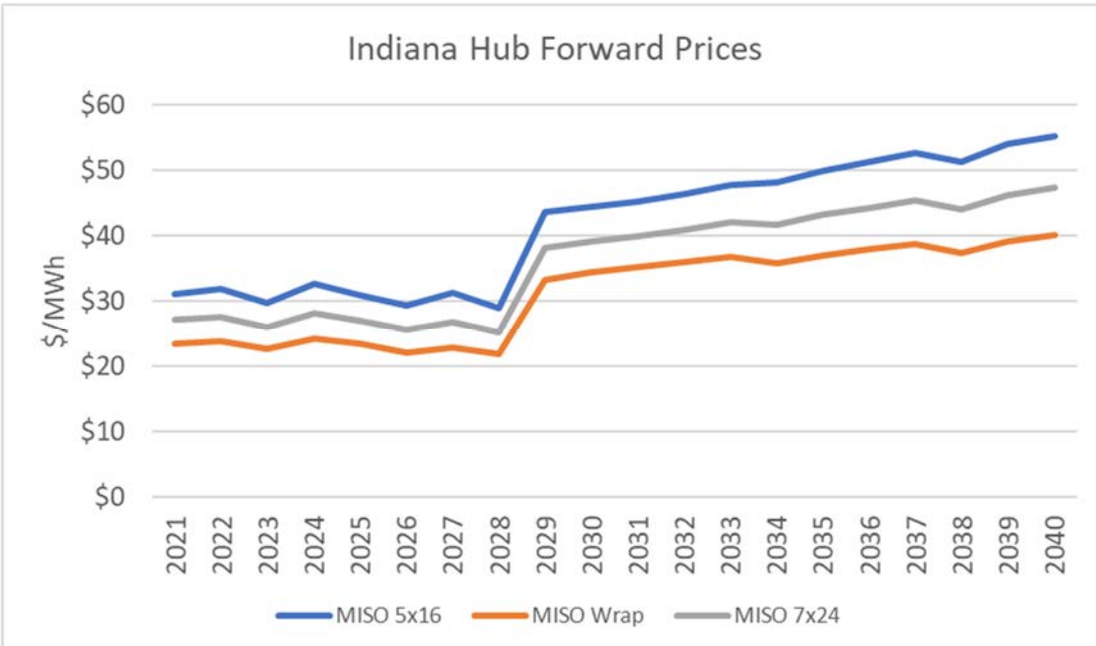


With the expansion having built mostly natural gas fired resources and renewables, it is no surprise that their share of generation within MISO increases over the study period while coal generation gradually declines through 2029. Generation for coal sees a step function down as the carbon tax comes into effect. Coal generation stabilizes, as do retirements, after this period, as "legacy" coal units become marginal suppliers of capacity and energy.

MISO Market Prices

The resulting MISO expansion under the base case assumptions results in forward prices that remain low until IMPA's carbon price assumption comes into markets in 2029. Notably, the penetration of low marginal cost renewables in the MISO market is expected to have a somewhat bearish effect on prices, with the year-over-year 5x16 price declining almost 8% between 2021 and 2028.

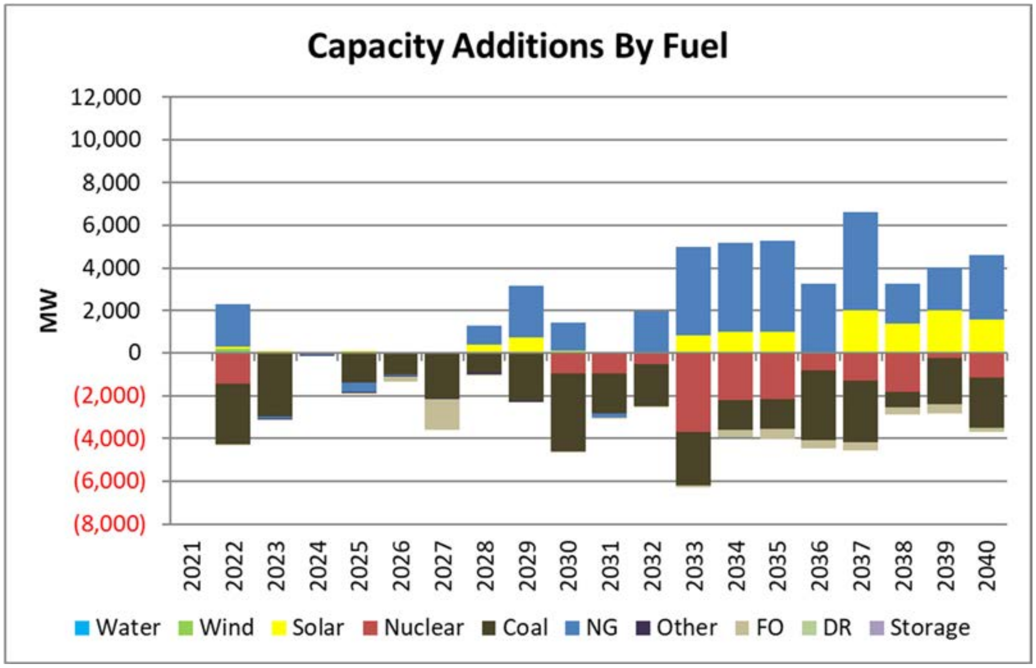
Figure 29 Base Case - Indiana Hub Forward Prices



With the increase of renewables in MISO and the downward pressure expected on pricing, the formation of a CO_2 regime in 2029 is somewhat mitigated.

The following charts illustrate the resulting build plan for the PJM market.

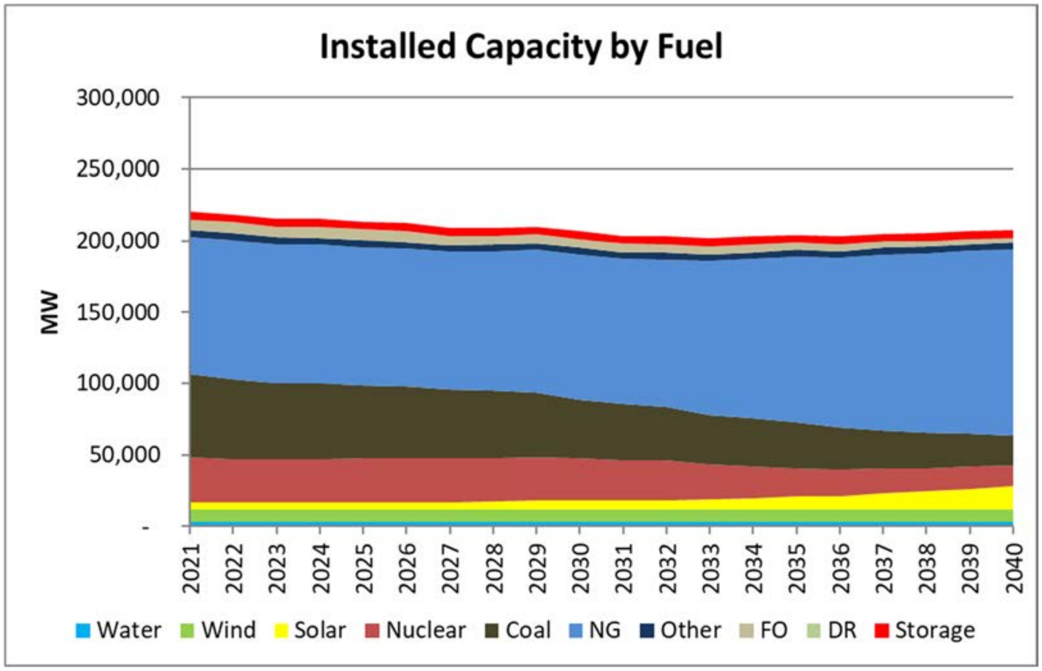
Figure 30 Base Case - PJM Net Capacity Additions by Fuel



With PJM forecasted to have reserve margins well into the 30% range by the summer of 2024[10] and comparatively few announced retirements, it is little surprise that the PJM resource mix is not projected to change much until 2029, when the CO2 tax is assumed to come into play. In PJM, the CO2 tax is expected to be a sufficient catalyst to set off additional coal retirements. In addition, age-based retirements of nuclear units are expected to become a bigger source of retirements than coal. The resulting build plan is largely solar and natural gas fired. The lack of wind is unsurprising as wind in PJM is historically comparatively more difficult and more expensive to develop. When combined with the sunsetting of the PTC, more economic sources of generation get built even in the face of a modest carbon tax.

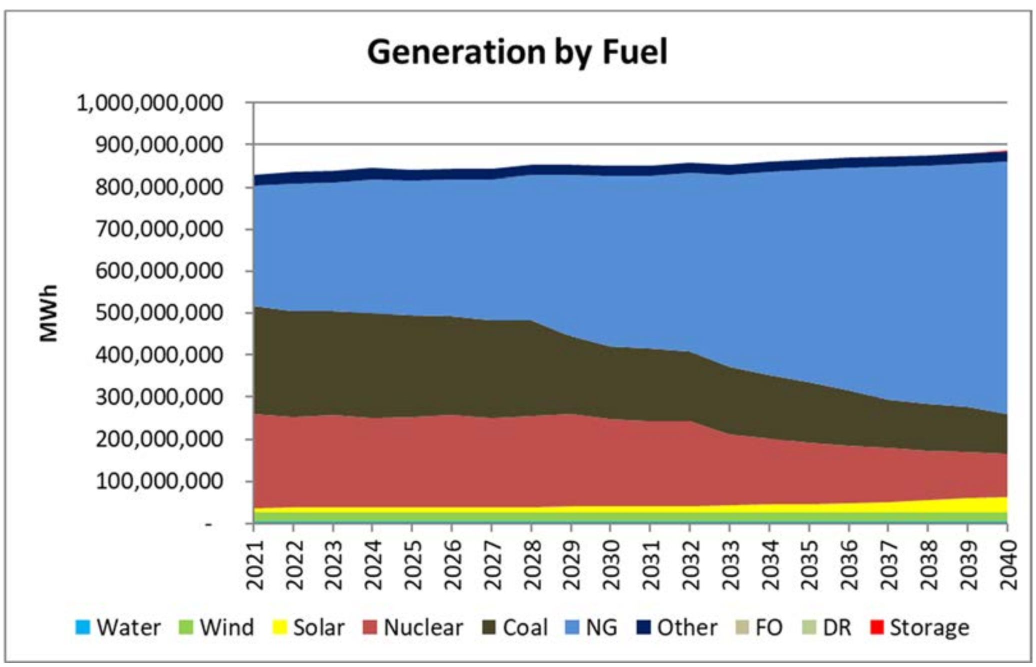
[10] https://www.pjm.com/-/media/planning/res-adeq/20200219-forecasted-reserve-margin-graph.ashx?la=en

Figure 31 Base Case - PJM Installed Capacity by Fuel



Gas is expected to be the primary fuel by installed capacity followed by solar, while coal and nuclear capacity is expected to gradually decline over the study period.

Figure 32 Base Case - PJM Generation by Fuel

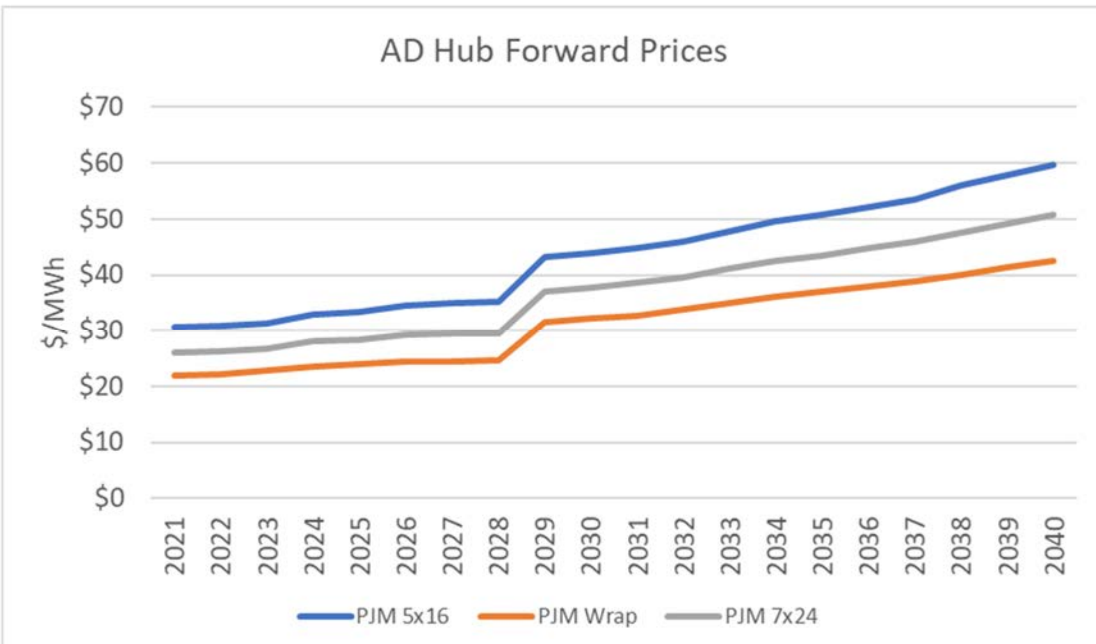


PJM sees a more persistent decline in coal generation over the study period than in MISO while natural gas fired generation carries most of the load requirement in PJM. Renewables are expected to be a small overall proportion of generation within PJM, largely driven by higher installed costs for renewable projects.

PJM Market Prices

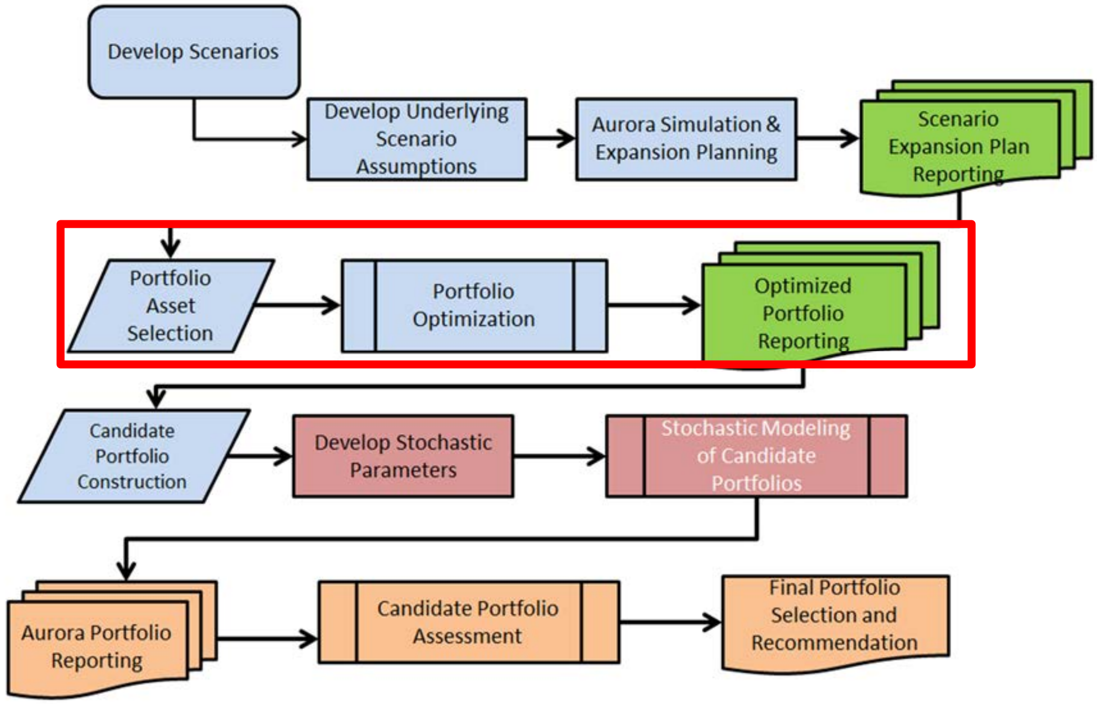
Under the base case assumptions in PJM, there is less expected buildout of renewables due to higher expected capital costs (i.e., land availability). When coupled with a PJM market that is currently long in reserves, the resulting market expansion merely replaces any retired coal with natural gas assets. The resulting forward curve generally trends upward reflecting higher expected natural gas costs and CO2. However, as natural gas already has significant market share in PJM as a feedstock, the impact from CO2 is somewhat lower than seen in MISO.

Figure 33 Base Case - PJM AD Hub Prices



11.7 Portfolio Selection

Process

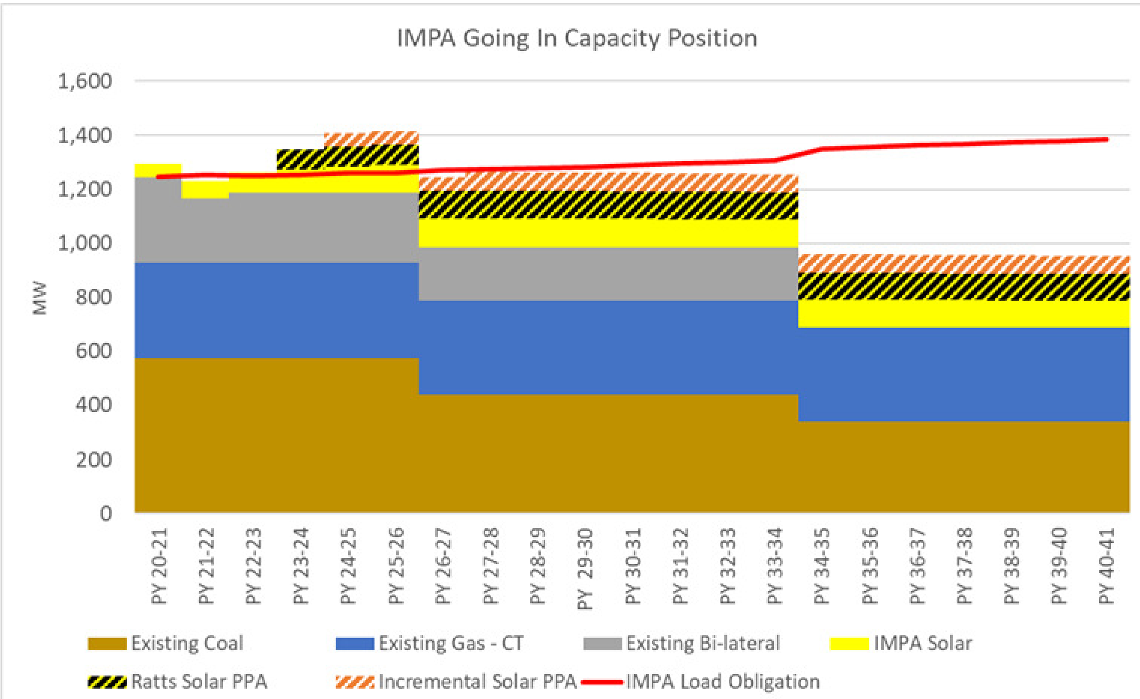


The next step in the process is for Aurora to optimize the IMPA portfolio within the market, based on the least cost system expansion derived from the previously calculated market expansion runs. Assets permitted to be selected by the portfolio optimizer are any existing assets in the ISO/RTOs being modeled, along with any new resources that were constructed to meet the energy and capacity requirements of the system. In addition, IMPA included various tranches of energy efficiency, which effectively act as decrements to IMPA load.

As a refresher, IMPA has load in two markets, with roughly 2/3 of that load is located in the MISO market and the balance in the PJM market. Due to long standing seams issues between the two RTOs, IMPA plans for each of these areas separately and views the two loads effectively as two separate portfolios. Planning activities revolve around the two primary products, energy and capacity, in each market. The following summarizes IMPA's capacity position on an overall market basis.

Over the coming 6 years, IMPA's MISO portfolio is expected to be relatively flat to its MISO obligation, assuming load forecasts are not dramatically influenced by new information (i.e., COVID-19, election, etc.). There is a need in planning year PY 21-22 due to the expiration of a bilateral agreement. This is partially offset by an increase in a separate bilateral capacity agreement. In PY 23-24, IMPA will have 150 MW of offtake from the Ratts Solar project and another 100 MW solar PPA in PY24-25 flattening the capacity position.

Figure 34 Base Case Going in Capacity Position



In Planning Year 26-27, IMPA is expected to lose 200 MW of unforced capacity (UCAP) due to the announced retirement of Gibson 5 and the expiration of a bilateral capacity contract. A large focus of this IRP is determining the optimal replacement for this lost capacity and energy.

As optimized by Aurora, the least cost solution under the base case assumptions is to replace Gibson capacity with approximately 156 MW of Advanced Combustion Turbine in PY 26-27 and 100 MW of solar in PY 25-26, with solar representing some of the last projects that would be eligible for an ITC that is greater than the terminal value of 10%.

As this represents a partial offtake from a 240 MW (196 MW Summer) facility and this is likely not commercially feasible. IMPA assumed the commercial reality would be closer to a self-build of a full Advanced CT machine as opposed to a partial interest in a single CT. The table below reflects the capacity position assuming a 196 MW (Summer) is added.

In PY34-35, IMPA's PJM portfolio sees the expiration of a 196 MW AEP full-requirements contract and the retirement of Whitewater Valley Station Units 1 and 2. Under the AEP agreement, reserves are carried as a feature of the contract. As a result, IMPA's load obligation ticks up slightly when this contract expires. Under the base case assumptions, the least cost solution to replace the lost capacity and energy is the addition of 208 MW of natural gas combined cycle and 100 MW of solar.

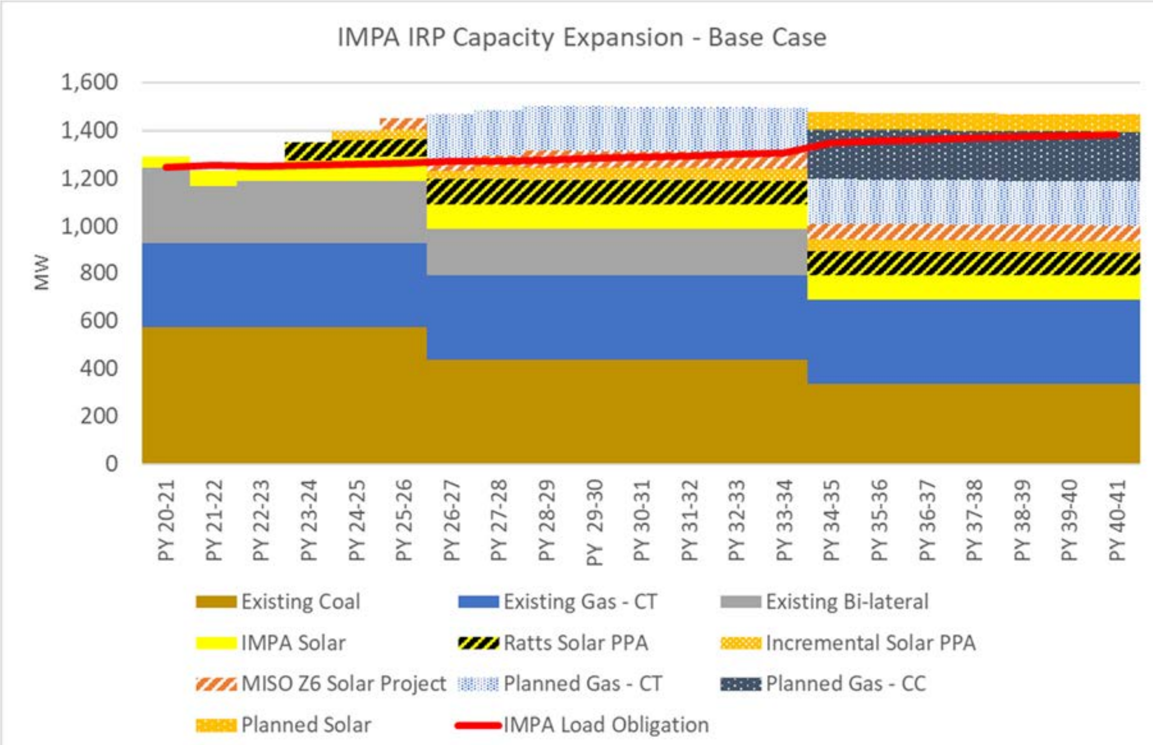
The table below illustrates a year-by-year summary of capacity additions and withdrawals under the base case summary and assumes that markets gradually move to reducing the capacity credit that renewable resources are eligible for.

Table 14 Base Case Expansion Plan

IMPA Base Case Plan - ICAP Capacity (Summer Ratings)					
Planning Year	MW Withdrawn	MW Withdrawn Notes	MW Capacity Added	MW Capacity Added Notes	Net Capacity Added/(Withdrawn)
PY 21-22	-100	Duke Option Expires	72	Increase in Bilateral Contract Qty, IMPA Solar	-28
PY 22-23			111	Increase in Bilateral Contract Qty + IMPA Solar + Alta Farms Wind PPA (Energy Only)	111
PY 23-24			161	Ratts Solar PPA + IMPA Solar	161
PY 24-25			111	Solar PPA (currently in negotiation) + IMPA Solar	111
PY 25-26			111	MISO Z6 Solar Project + IMPA Solar	111
PY 26-27	-231	Gibson #5 Retirement/Bilateral Capacity Expiration	207	Planned Natural Gas Combustion Turbine + IMPA Solar	-24
PY 27-28					
PY 28-29					
PY 29-30					
PY 30-31					
PY 31-32					
PY 32-33					
PY 33-34					
PY 34-35	-286	AEP Contract Expiration/WWVS Retirement	316	Planned NG Combined Cycle and Solar	30
PY 35-36					
PY 36-37					
PY 37-38					
PY 38-39					
PY 39-40					
PY 40-41					

The chart below illustrates IMPA's capacity position after optimization, assuming standard renewable capacity credits.

Figure 35 Base Case Expansion Plan



While this solution makes the MISO component of IMPA's portfolio long capacity, it gives IMPA flexibility in procuring energy needs on a year-to-year basis and the additional offtake also hedges against risk to reductions in the capacity credit assigned to renewable resources.

The chart above assumes current MISO rules regarding solar accreditation hold throughout the planning horizon. Currently solar receives a 50% capacity credit until operating history for the asset has been established, then capacity credit is linked to the asset's performance for HE 15-17. IMPA assumes a 50% capacity credit for 3 years before being eligible for 70%. IMPA chose 70% as the maximum based on IMPA's own solar park history and estimates from solar developers on project capacity values.

However, MISO has increasingly voiced concern over ever-increasing renewable penetration and its impact to reliability. At the time of writing, no definitive plans have been put into place to reduce the capacity credit for solar, however wind resources are currently the target of receiving a credit based on their Effective Load Carrying Capability (ELCC). MISO has shown that as penetration of wind and solar assets increases across the footprint, their ability to carry load during peak conditions decreases. [11]

[11] https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf

Figure 36 MISO Wind and Solar ELCC

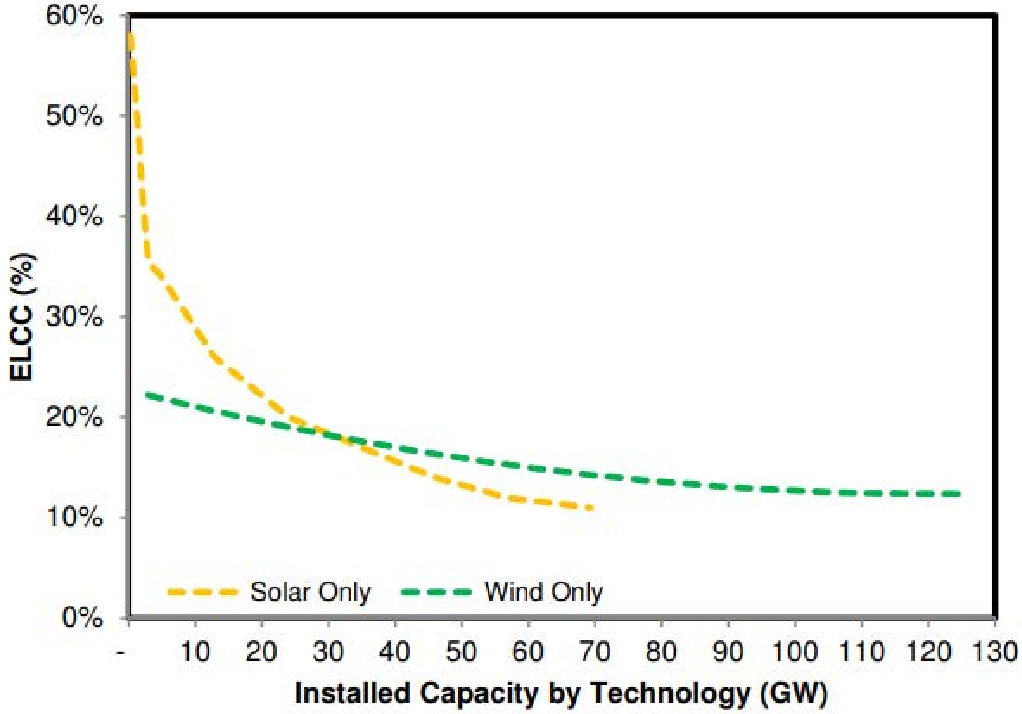


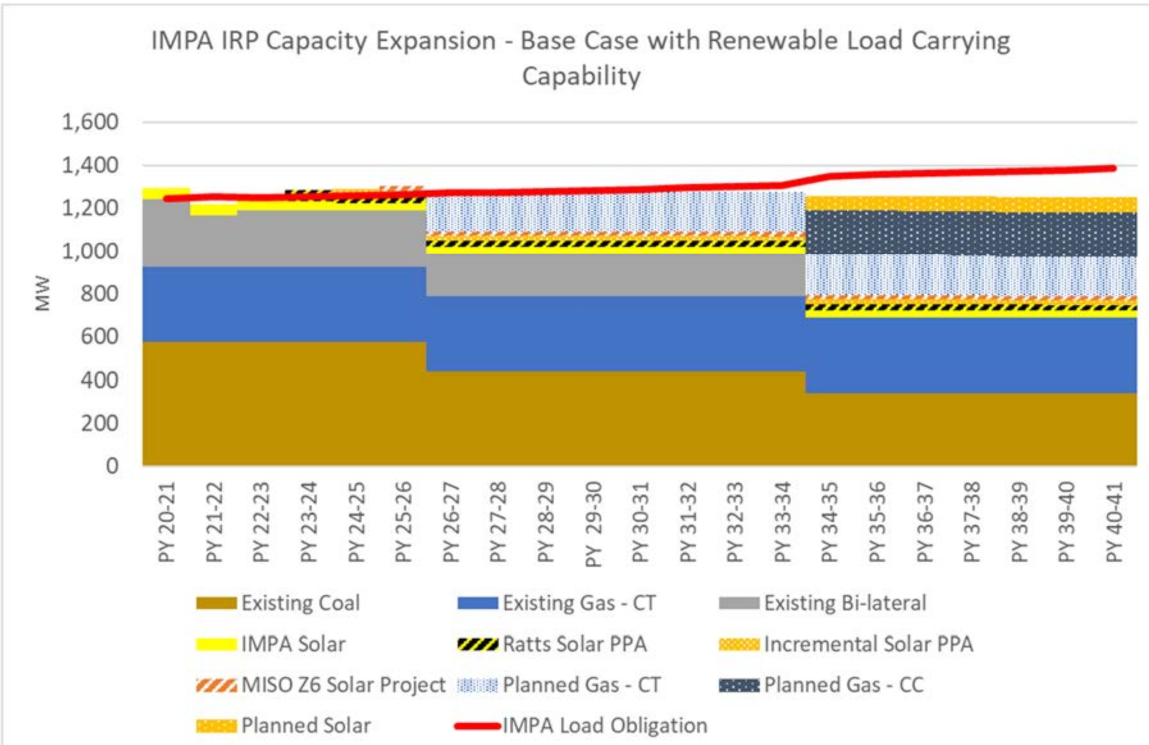
Figure 2 Wind and solar ELCC curves as a function of installed capacity

Given the state of MISO's generation interconnection queue, solar will play a much bigger role in the composition of MISO's portfolio. PJM is somewhat ahead of MISO procedurally and the "writing on the wall" for renewables is that they will be subject to more stringent (and lower), capacity accreditation from the ISOs in the future.

As a sensitivity to IMPA's capacity position, the chart below shows IMPA's MISO capacity position assuming the commercially feasible 240 MW CT (196 MW Summer) plus a reduction in the solar capacity credit from 70% (peak) to 20% in PY 26-27.

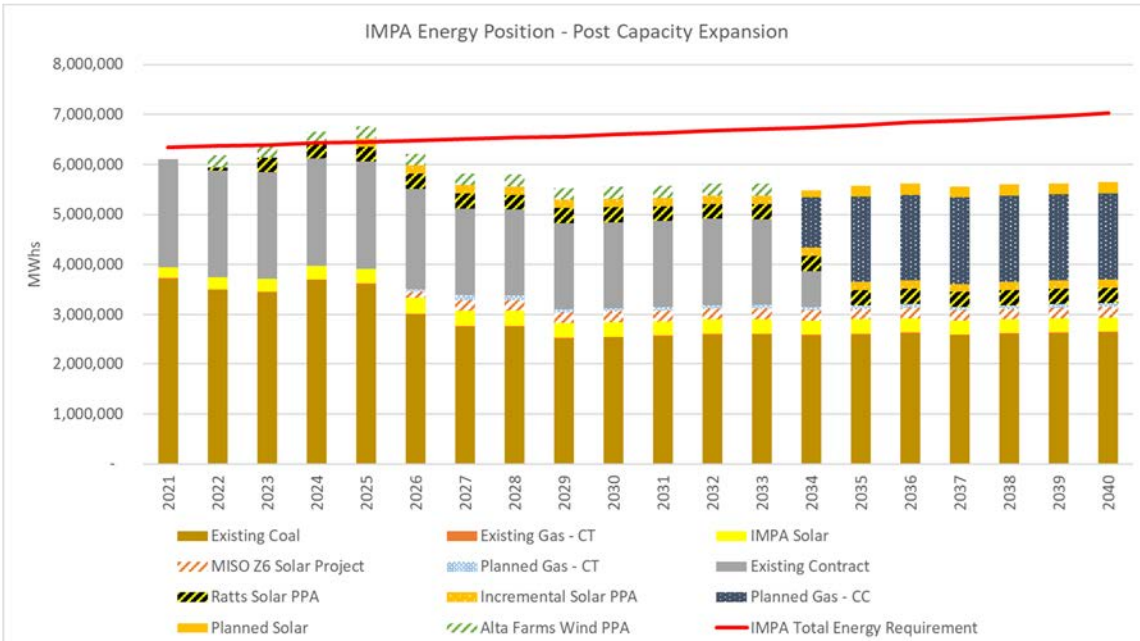
Should MISO reduce the capacity credit of solar, IMPA will still have the full offtake of the CT. Depending on load uncertainty and risks of potential COVID related demand destruction, the IMPA portfolio would be well positioned for these uncertainties.

Figure 37 Base Case Expansion Plan with Adjusted ELCC



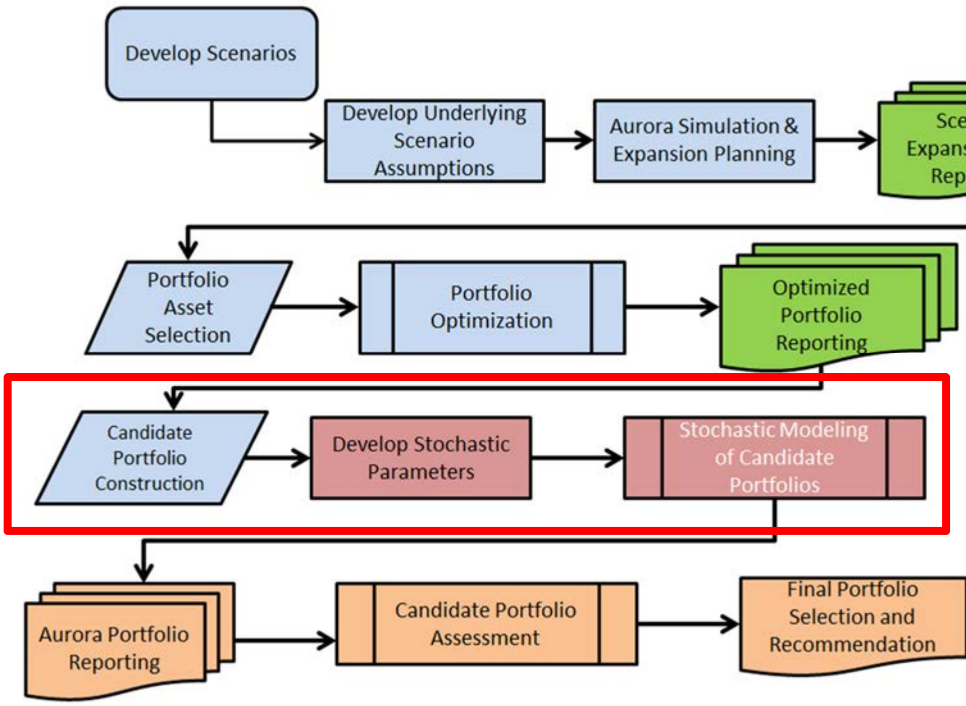
When planning for energy needs, IMPA typically allows for a relatively small position to be taken to spot markets with increasing volumes left unhedged over time. This strategy has allowed IMPA flexibility with regard to changes in load or market conditions. As a practical matter, IMPA can easily pivot between the cheaper of additional renewable resources or forward power purchases as market conditions dictate. As illustrated in the following chart, IMPA left the energy position open to reflect the ongoing real option to defer committing to an energy need in 2026.

Figure 38 Base Case Post Expansion Energy Position



11.8 Stochastics

Process



At this point in the process, the candidate portfolio has been identified by the Aurora optimization and now the risk of the portfolio needs to be established. In order to model the stochastic parameters of relevance, IMPA first needed to establish volatility and correlations across fuels, system demand and IMPA's own system demand. Primary risk drivers include:

- Natural Gas (Henry Hub) Prices
- Coal Prices
- MISO System Load
- PJM System Load
- Emissions Costs
- IMPA Load

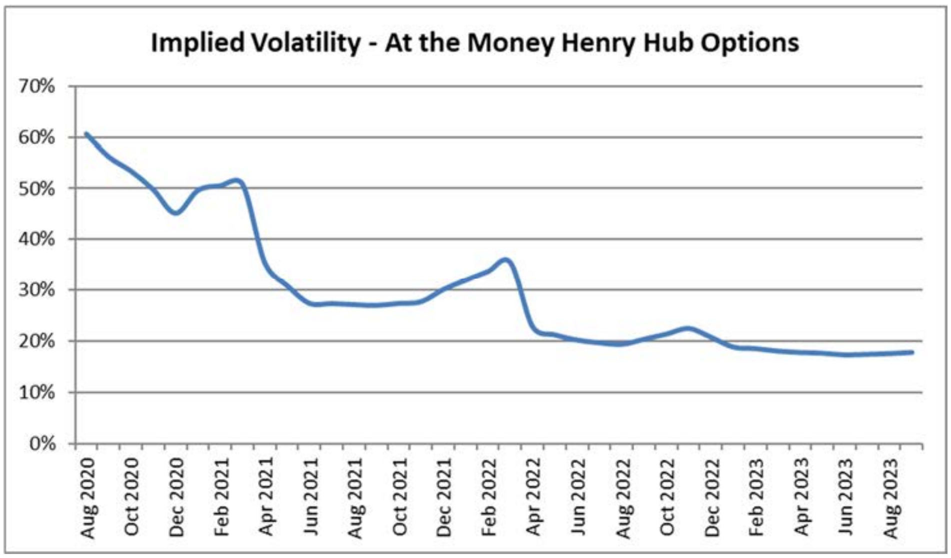
Historical data was used to establish correlations on emissions, coal, and load data while for Henry Hub natural gas, implied volatility on options on natural gas futures were used. Correlation data showed very little change from the last IRP. Those values are shown below.

Table 15 Base Case Correlations

Monthly Correlations 2012 to Present				
	Midcontinent ISO Load	*PJM Load*	*HH Gas*	*Coal*
Midcontinent ISO Load	1.00			
PJM Load Load	0.63	1.00		
HH Gas	0.10	0.20	1.00	
Coal	-0.62	-0.01	0.45	1.00

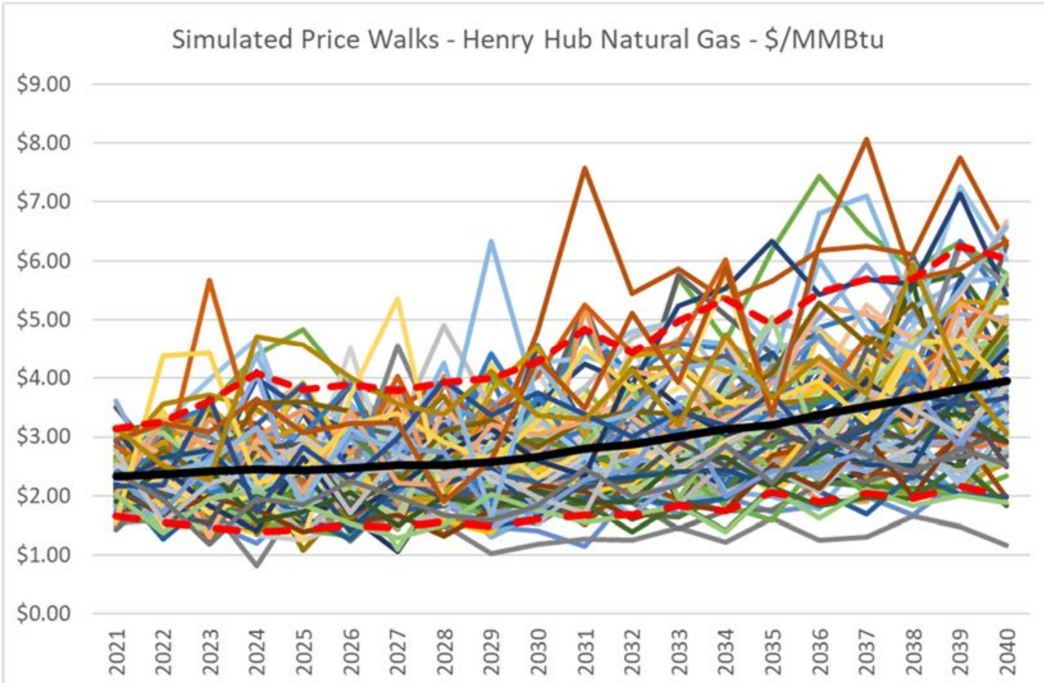
For natural gas volatility, as noted above, IMPA uses observed prices on natural gas options on futures to create a term structure of volatility. At the time of writing, the term structure for more liquid options carried implied volatilities resulting in the term structure illustrated below.

Figure 39 Base Case - Henry Hub Implied Volatility



As the IRP horizon extends beyond this range of liquid option pricing, IMPA assumes volatility implied in options gradually tapers down over time from levels seen in 2023. The following charts illustrate the resultant outcomes across all iterations of the simulation for the variables that were modeled stochastically.

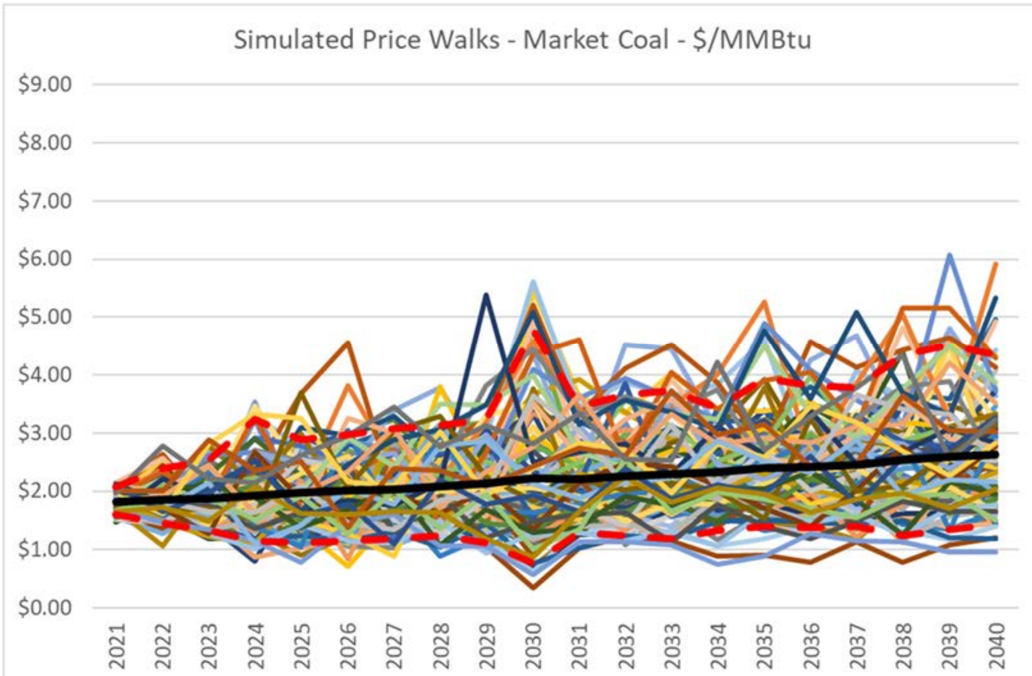
Figure 40 Base Case - Henry Hub Gas Simulated Price Walks



The relatively wide dispersion in 2021 results from the time component of annualized volatility. The annual means are illustrated by the heavy black line while the P5 and P95 prices in each year are represented by the dotted red lines. Given the term structure of volatility for natural gas and current forward market for Henry Hub futures, natural gas prices are expected to remain low for several years with a relatively low probability of exceeding even $4.00/MMBtu.

The following chart illustrates the same information but for market coal. As modeled in the base case, coal is somewhat cheaper than natural gas at the mean, and historically has had less volatility.

Figure 41 Base Case - Market Coal Simulated Price Walks

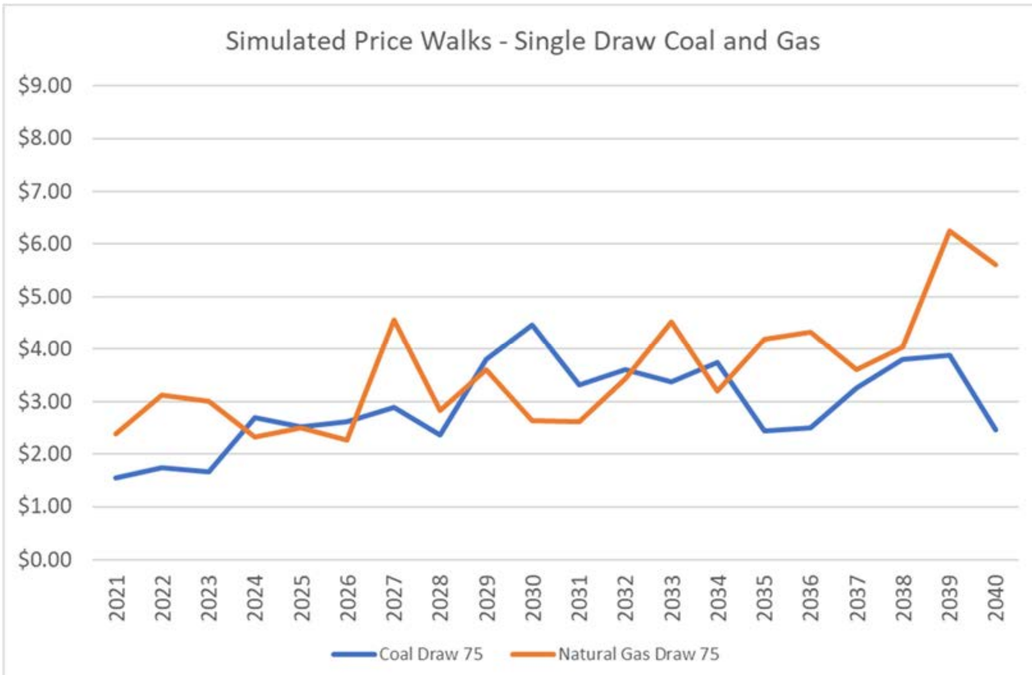


The average annual P95 for natural gas is $4.57 while for coal this value is only $3.47. Ignoring effects of correlation, this would imply that natural volatility puts it at a disadvantage to coal on the basis that, at a p95 cutoff, coal will always be cheaper than natural gas. However, this is where the importance of modeling cross commodity correlation comes into play.

By capturing cross commodity correlations, IMPA can capture some of the real-world uncertainty of what the most competitive fuel will be in the future.

The chart below illustrates this dynamic by just showing a single price draw on the same chart for both coal and natural gas.

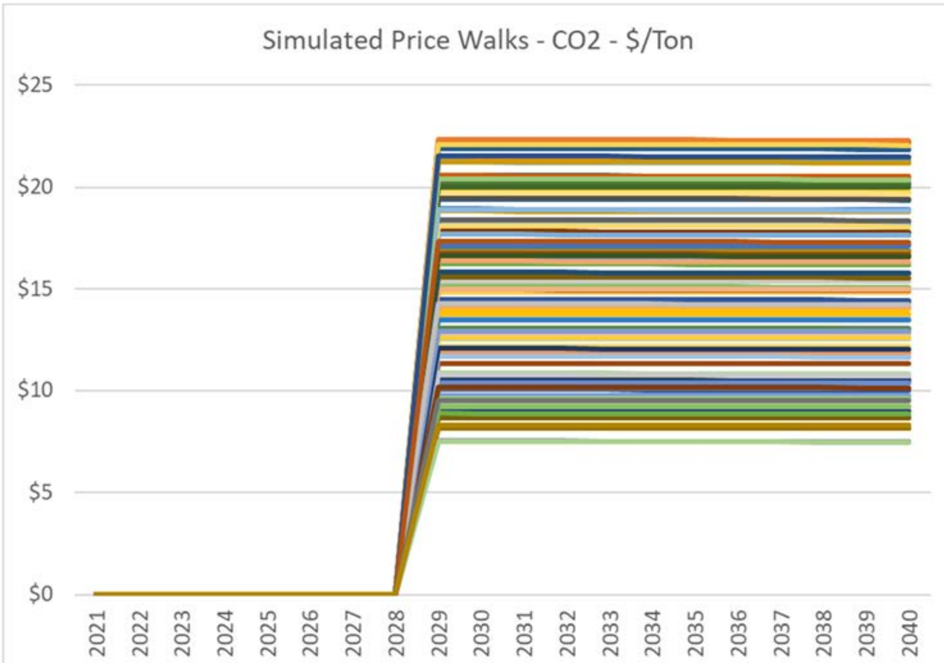
Figure 42 Base Case - Coal Price vs Gas Price Simulated Walk



While it is only 1 iteration of the 100 modeled, it illustrates the imperfect correlation between these two competing fuels. While coal, in this iteration, is generally less expensive than natural gas, there are years where the two fuels flip competitiveness. This ultimately underscores the risk of fixed asset decisions with very long lives in a very competitive marketplace.

IMPA models CO2 pricing with respect to markets having to live in a world where the policy is enacted yet the price the policy sets is relatively uncertain. The chart below illustrates the capturing of this uncertainty around the magnitude of pricing once CO2 is expected to come into play in 2029.

Figure 43 Base Case - CO2 Simulated Price Walks

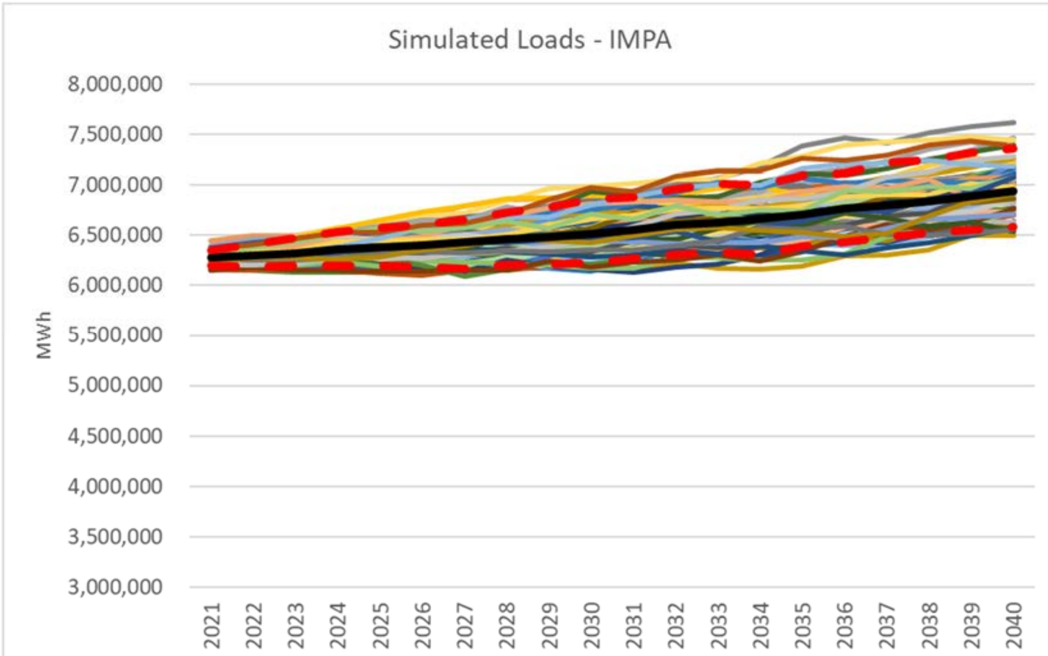


As shown, the expected range of CO2 pricing under the stochastic base case ranges from $7.50/ton on the low side to roughly $22 on the high side, with an expected price of $15/ton.

With the base case optimized in a deterministic world where carbon prices are expected to remain stable, this captures the risk to the resource plan associated with deviations from the expectation of a relatively fixed CO2 price.

The final stochastic parameter modeled for the IRP is system and IMPA loads. The chart below illustrates the simulated loads by iteration for IMPA.

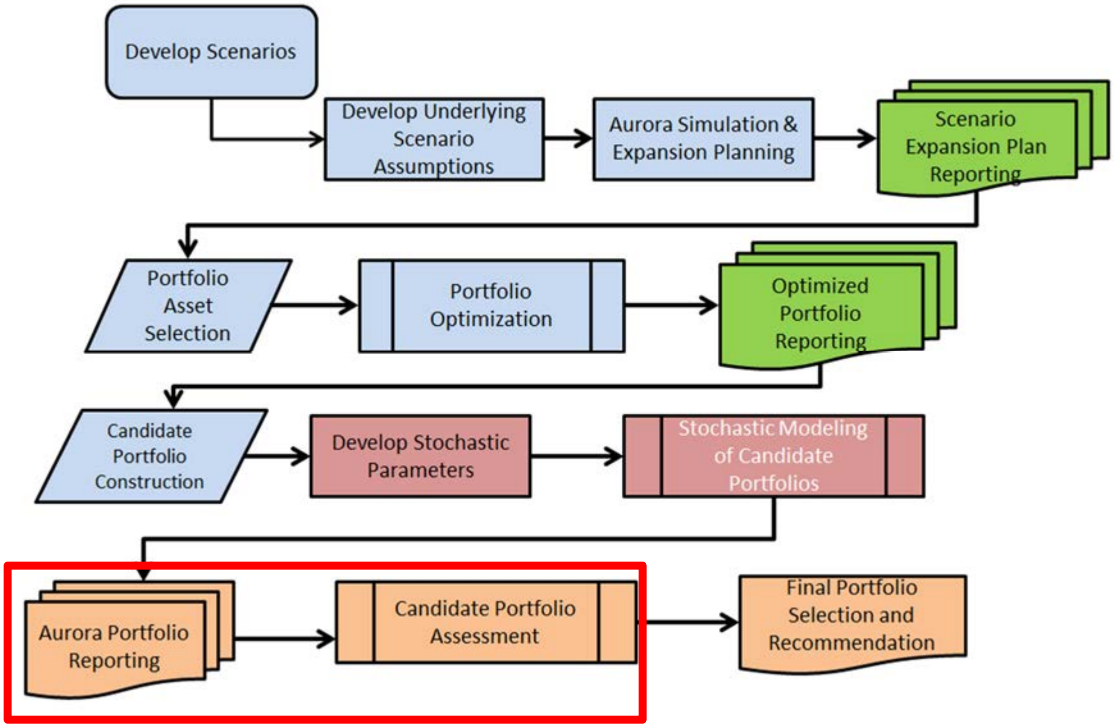
Figure 44 Base Case – Simulated Load Walks



Broadly speaking IMPA loads and system loads are highly correlated so that a high load draw for IMPA should result in a high system load draw. The correlation between system and IMPA load is important so as not to bias outcomes that favor build plans that benefit from excess off-system sales for times when IMPA load is low and system load is high.

11.9 Portfolio Assessment

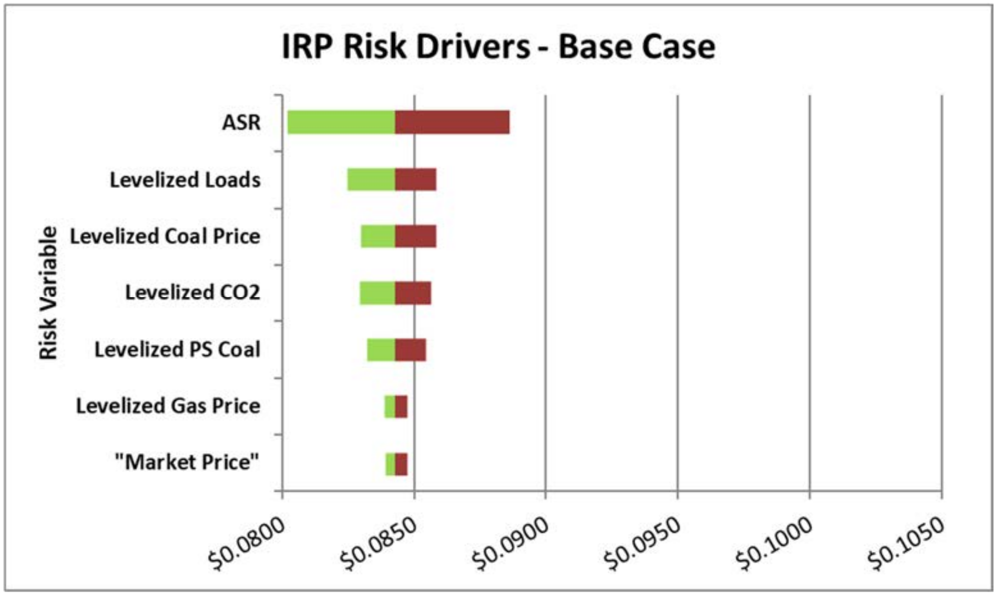
Process



While the candidate portfolio is formed from deterministic data, the stochastic outcomes test the portfolio composition for risk exposures and robustness to those exposures. As noted in the "Portfolio Selection" section, IMPA's least cost portfolio, as determined by Aurora replaces retiring Gibson 5 capacity with a natural gas combustion turbine. In addition to this, 100 MW of solar was selected. This portfolio was then run stochastically with the inputs from the previous section and the resulting outputs were entered into the MCR financial model.

These outputs were then used to assess the risk of the candidate portfolio in the stochastic world. The “tornado” chart below illustrates the risk exposures from key risk variables.

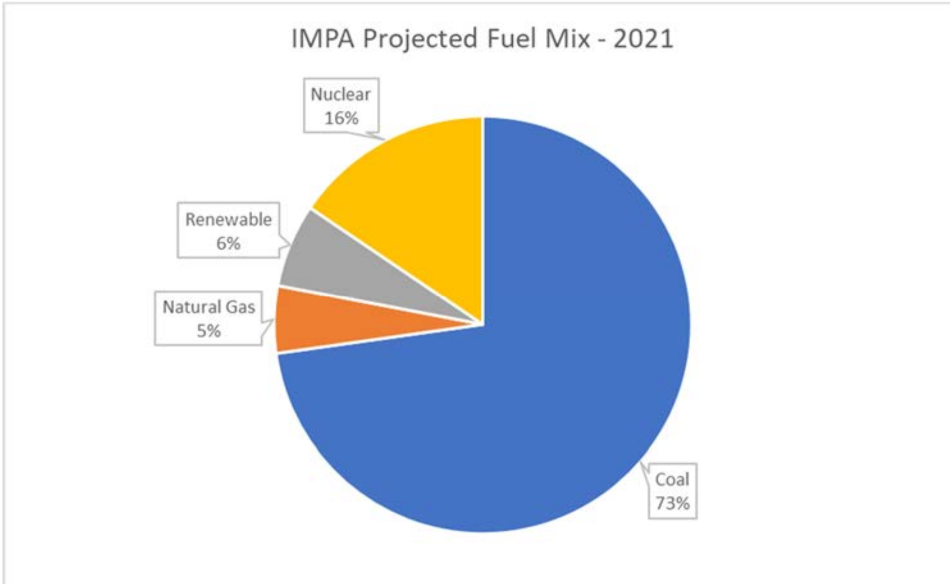
Figure 45 Base Case - Tornado Chart



ASR is IMPA’s average system rate in cents per kWh. Under uncertain conditions, the implementation of the base case candidate portfolio has a p5 value of just over $.08/kWh, a mean of $.0843/kWh, and a p95 of $.0886/kWh. In order to determine the risk drivers, a multiple regression was run on system rate, ranked highest to lowest against levelized risk variables. As demonstrated above, the largest risk to IMPA under the base portfolio are expected loads. Given the level of fixed investment, higher loads help lower the ASR, while lower loads increase it. The second greatest risk is the price of coal for the IMPA fleet, excluding Prairie State. Despite losing Gibson 5 due to retirement in 2026, IMPA’s fleet still is expected to be somewhat coal dominant with respect to fuel exposures under the base plan.

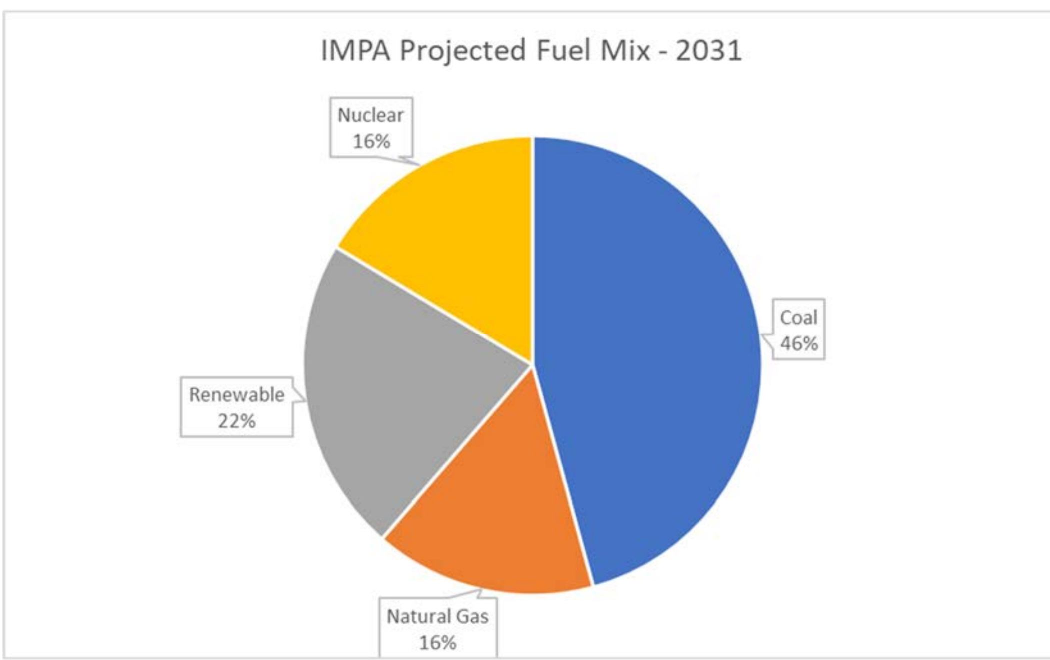
In order to place context around this, consider the following charts illustrating the projected fuel mix for IMPA’s power supply for 2021 and 2031.

Figure 46 Base Case - 2021 Fuel Mix



It is important to consider that in calculating this number, IMPA estimates fuel exposures from full requirements contracts (such as with AEP), forward purchases, and market purchases. This explains the 16% nuclear exposure in the chart above, which stems from IMPA load served by the AEP/I&M full requirements contract. Entering next year, IMPA's fuel mix is expected to be a little over 73% coal. However, transitioning to 2031, coal exposure is expected to shrink to 46% coal. Nevertheless, coal remains the single largest exposure.

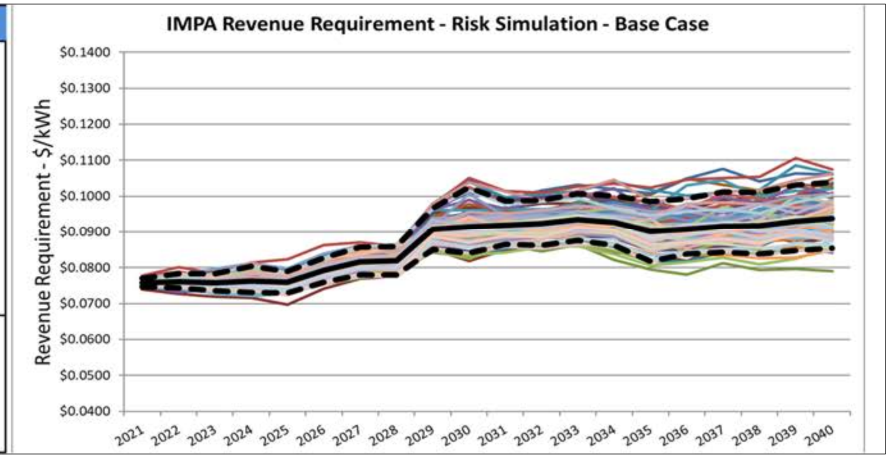
Figure 47 Base Case - 2031 Fuel Mix



11.10 BASE CASE SUMMARY

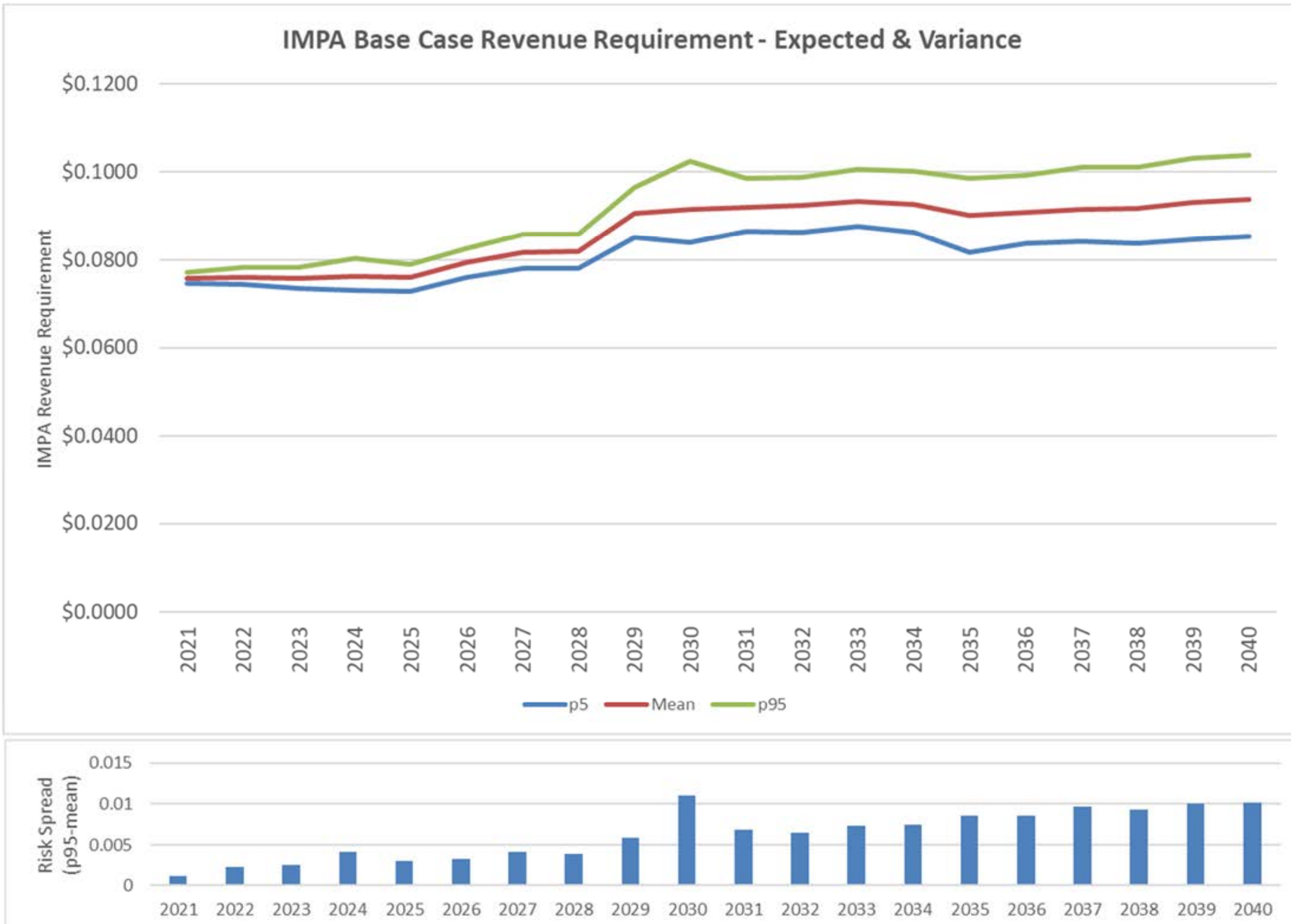
Plan Summary: In this optimization, generation retirements include Gibson 5 on 5/31/2026 (156 MW) and Whitewater Valley Station on 5/31/2034 (90 MW). Over the study period, IMPA sees the expiration of 363 MW of bilateral/full requirements capacity contracts. Planned replacements include: 150MW of solar from the Ratts Solar project effective in PY 23-24, 100MW from a MISO solar project currently under negotiation effective the following year, a 100 MW solar project in PY 25-26 and 196 MW (summer) of natural gas CT for PY 26-27, and 208 MW of natural gas CC and 100 MW of solar in PY 34-35.

Drivers	Base Case
Economic Growth	1.8%
Capital Costs	Reference
Load Forecast	IMPA Base Case
Natural Gas Prices	Reference
Coal Price	Reference
CO2 Policy	$15/Ton in 2029
RPS	Only extant state requirements
Reserve Margin	Reference Area
Asset Retirements - ICAP MW	-246
Net Market Capacity Transactions - ICAP MW	-321
Natural Gas Additions - ICAP MW	412
Renewable Additions - ICAP MW	627

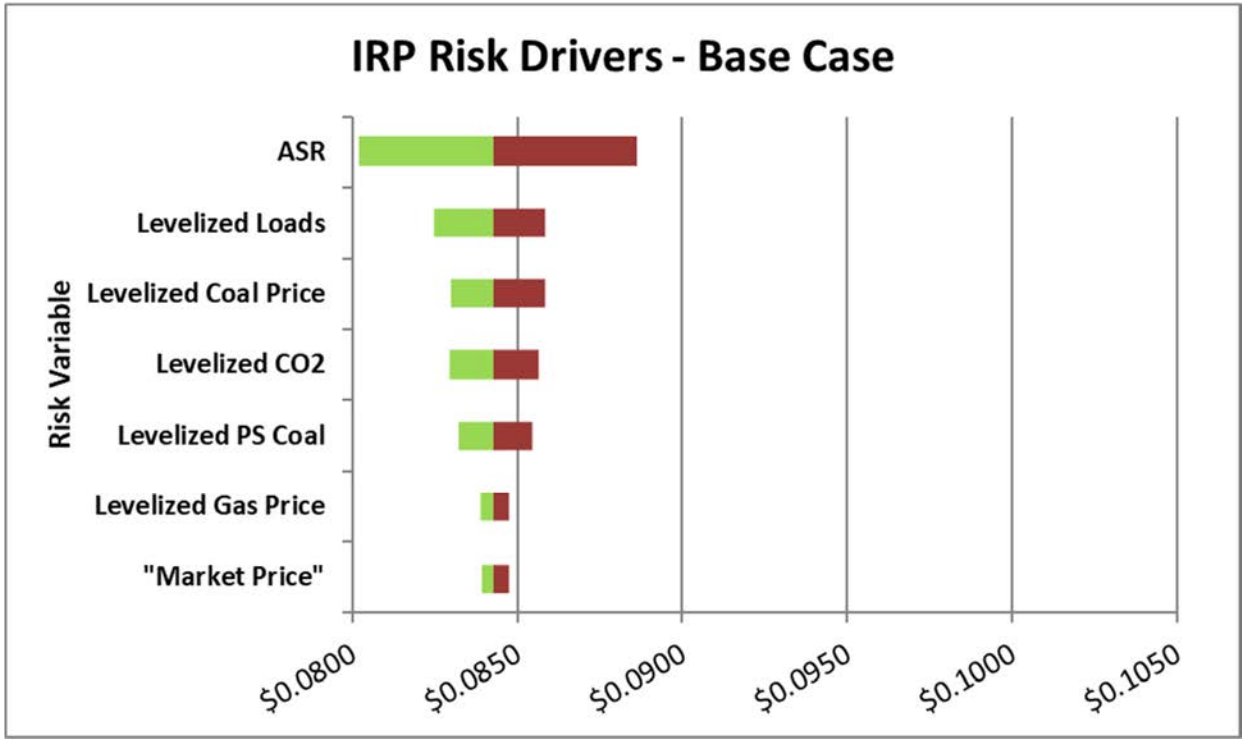


Plan Observations: With solar tax incentives winding down, IMPA has already begun to layer in solar prior to the sunsetting of the ITC. While this is expected to make IMPA slightly long energy in the short term, it offsets a gap in energy need after the 2026 retirement of Gibson 5. The least cost capacity solution is to build a 240 MW (196 MW Summer) CT, to fill MISO capacity obligations. For additional energy requirements in MISO, the model selected a third solar project (100 MW) for PY25-26. IMPA expects to gradually fill any remaining energy position with the cheaper of market forwards or renewables, depending on policy landscape and comparative economics. On the PJM side, PY 34-35 sees the simultaneous expiration of the AEP full-requirements contract and the retirement of WWVS, which are replaced with a natural gas combined cycle and solar.

Risk Profile Observations: IMPA's optimal portfolio is relatively low risk even after the presumed CO2 tax regime becomes effective. Over the study period the risk to the portfolio is generally under $.01/kWh. This is considerably lower than illustrated in IMPA's previous IRP filing largely due to a lower and later CO2 tax and lower commodity price volatility.



Tornado Chart Observations: As discussed previously, IMPA's largest risk in the base case revolves around the uncertainty of loads, with higher loads generally helping to lower the system cost while loss of load generally increases system cost as higher fixed costs are spread over a lower quantity of MWhs. By replacing capacity with a combination of peaking natural gas and renewable resources, the optimal portfolio lowers IMPA's exposure to CO_2 and natural gas prices. Coal remains comparatively large from a risk standpoint despite the retirement of Gibson 5 and WWVS due to a combination of IMPA's remaining coal fleet and exposure through market purchases and contracts.



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12 GREEN CASE

12.1 IRP SCENARIO DEVELOPMENT

This section sets the groundwork for the assumptions used to construct the green case, albeit in a somewhat more condensed layout than was used for the base case because some assumptions in the green case remain unchanged from the base case (e.g., capital costs). This section will generally follow the same format as the base case description.

12.2 CARBON POLICY

As this case is the "Green Case" IMPA opted to set up a world in which a transition away from carbon was quick and much more aggressive than outlined in the base case. Given the uncertainty surrounding the upcoming election, IMPA staff started by examining what sorts of energy and climate change policies have been proposed during the last year. At the time of writing, three primary bills dealing specifically with carbon legislation had been proposed: The Climate Action Rebate Act of 2019 (CAR Act), The Stemming Warming and Augmenting Pay Act (SWAP Act), and The Raise Wages, Cut Carbon Act of 2019 (RWCC Act).

Under the CAR Act, a $15/ton tax on CO_2 would be implemented and increased by $15/ton per year. The tax would double any year CO_2 reduction targets were not met. However, the escalation would cease once CO_2 levels were 10% below a 2017 base year. 70% of the tax revenue would be redistributed to low and middle income families as a monthly dividend.

The SWAP Act aims to reduce CO_2 emissions by 42% by 2030 versus 2005 levels (cyclical highs) by instituting a $30/ton tax on CO_2 increasing by 5% per year. Every two years, emissions are assessed and if goals aren't met, the tax goes up by $3/ton.

Finally, the RWCC Act proposes a $40/ton tax with a 2.5% increase each year PLUS an additional inflation adjustment. This tax would be designed to phase out once a 20% reduction in CO_2 emissions versus 2005 levels was achieved.

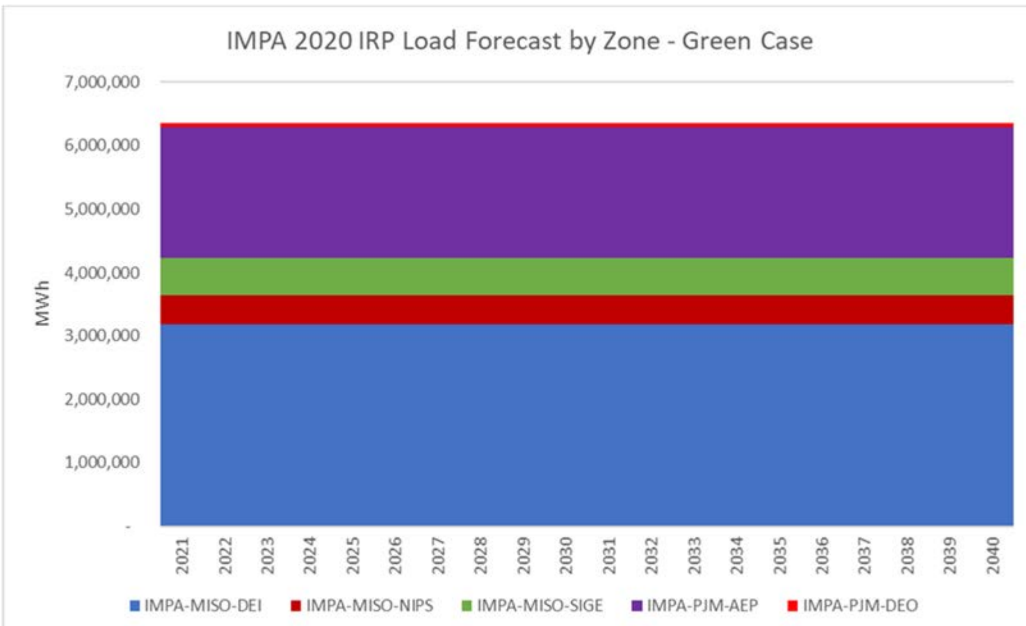
For this IRP, IMPA wanted to see the impacts to the system of a more punitive CO_2 regime and thus elected to model CO_2 taxes as contemplated under the CAR Act. However, as a deviation from the policy as proposed, IMPA allowed CO_2 prices to increase by $10/ton, per year until reaching a cap of $75/ton.

With respect to the timing of the tax, IMPA assumed this would probably be a second-term accomplishment of a potential Biden/Democratic successor administration and as such, IMPA assumes the tax is effective beginning in 2025.

12.3 LOAD FORECASTS – IMPA AND ISOS/RTOS

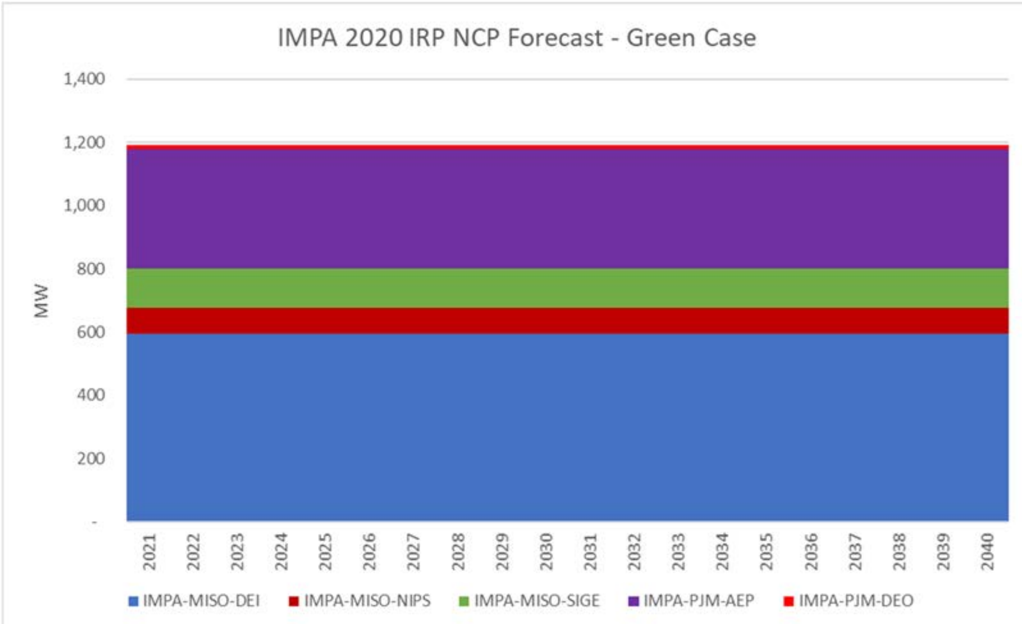
Under the IMPA CAR Act variant, IMPA assumed that despite the redistribution of tax revenue, most consumers would see the carbon intensive portions of their consumption go up in price (i.e. electricity) and would find ways to limit consumption of those goods. Furthermore, they may even be incentivized to move to distributed generation as a means of supply. With base case growth in loads being a very modest .5% over the IRP horizon, IMPA felt that, at best, loads under a green world would remain flat over the horizon despite the fact that a CO2 tax redistributed to families may spur increases in aggregate demand.

Figure 48 Green Case - IMPA Energy Forecast



As with the energy forecast in the Green Case, IMPA expects that a CO2 tax will cause consumers to be more conscious of their energy use during high periods of demand and consequently, IMPA will see flat demand growth over the IRP horizon. The figure below shows the peak demand forecast for IMPA zones over the horizon.

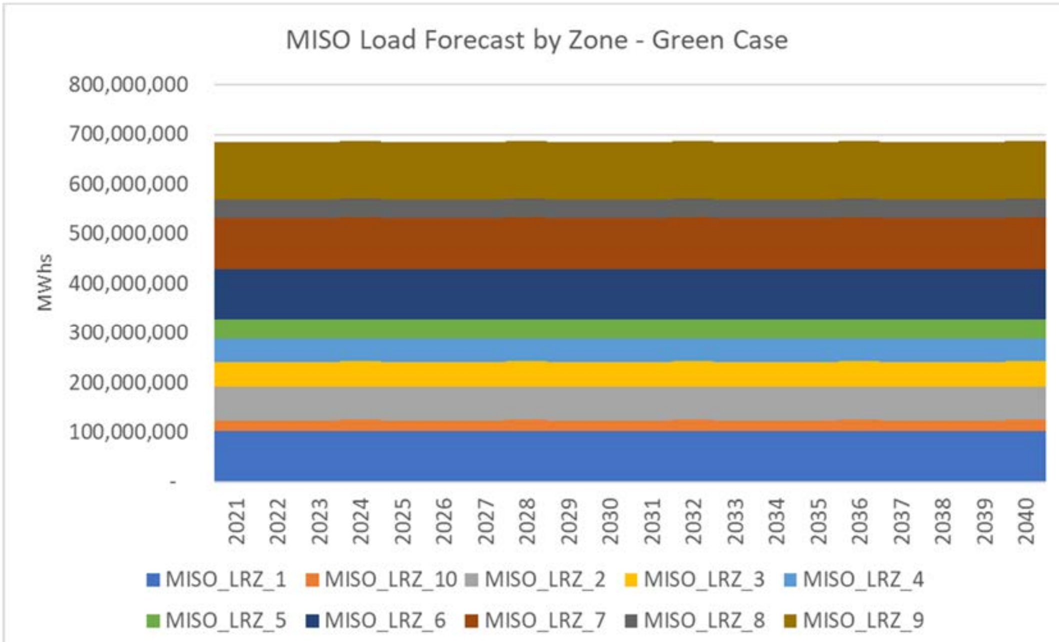
Figure 49 Green Case - IMPA Demand Forecast



Further reductions in consumer use stemming from a high CO2 tax would be due to increased penetration of distributed energy resources (DERs) and additional behind the meter generation.

In the green case, IMPA assumed that system load growth would likely correlate with any impacts felt by IMPA in a green world. The theme overall would be defined by a world that was carbon adverse, with a punitive tax regime to limit CO2 emissions. In turn, consumers would take steps to lower their energy usage over time. The chart below illustrates the system forecast for energy in MISO by zone.

Figure 50 Green Case – MISO Energy Forecast



While there may be some pockets of load growth due to increased EV penetration in a carbon adverse world, IMPA believes those are likely to be drivers in urban areas. While it is too early to tell for certain, there also appeared to be some demographic shifts away from cities and into more rural areas during the COVID pandemic. Should these remain in place, that may mute any impacts from EV penetration.

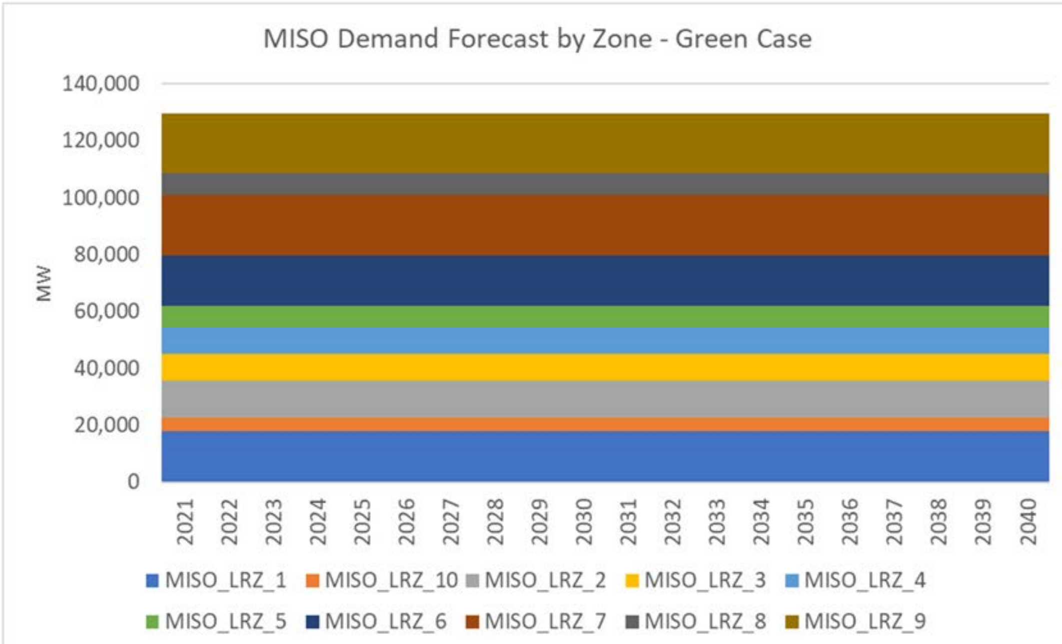
While EV penetration is undisputedly growing, it is notable that publicly accessible charging infrastructure is still relatively early in adoption in the United States. [12],[13]

[12] IEA, Publicly accessible electric vehicle slow chargers by country, 2019, IEA, Paris https://www.iea.org/data-and-statistics/charts/publicly-accessible-electric-vehicle-slow-chargers-by-country-2019

[13] IEA, Publicly accessible electric vehicle fast chargers by country, 2019, IEA, Paris https://www.iea.org/data-and-statistics/charts/publicly-accessible-electric-vehicle-fast-chargers-by-country-2019

Similarly, peak demand is expected to remain flat for all MISO zones as well and are shown in the chart below.

Figure 51 Green Case – MISO Demand Forecast



In the Green Case, IMPA assumes flat load growth is the pervasive theme and this extends to PJM loads and peak demands across all of PJM's zones.

Figure 52 Green Case – PJM Energy Forecast

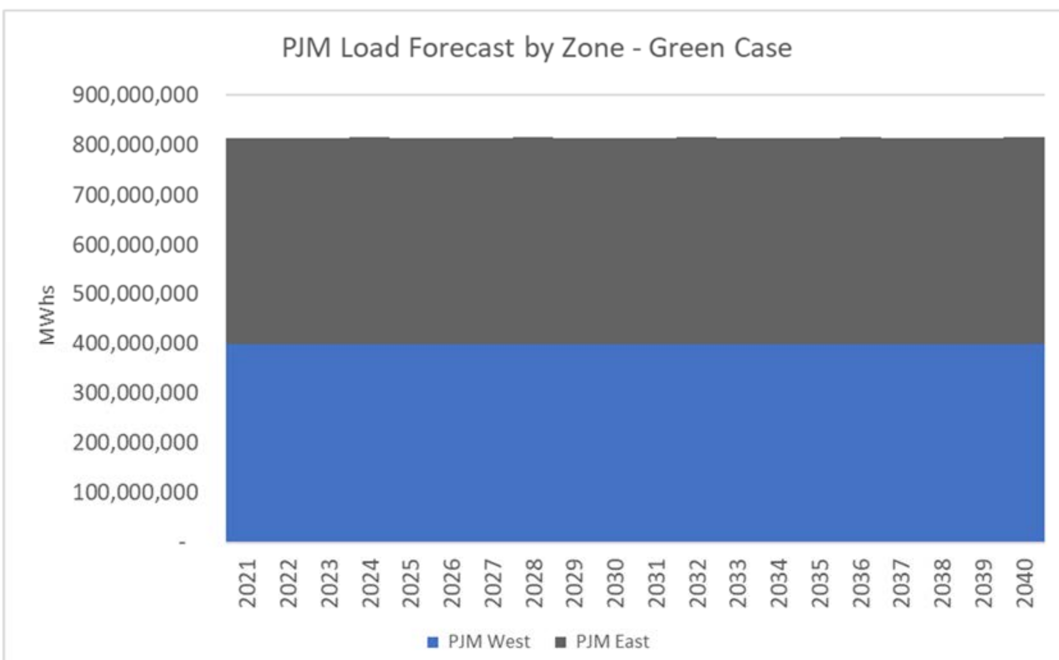
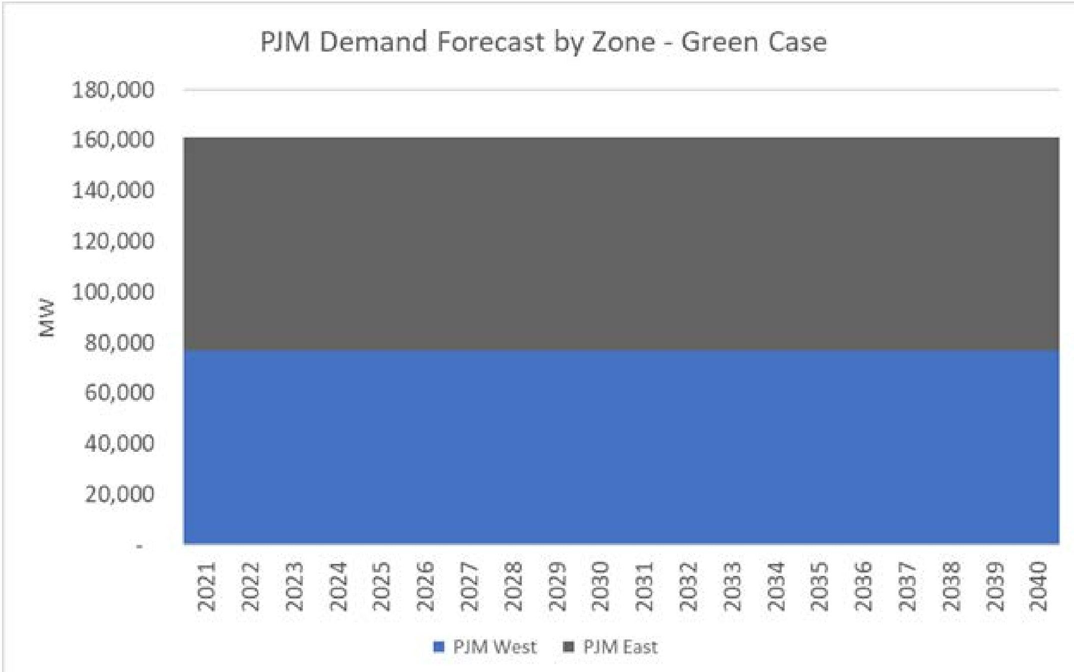


Figure 53 Green Case – PJM Demand Forecast

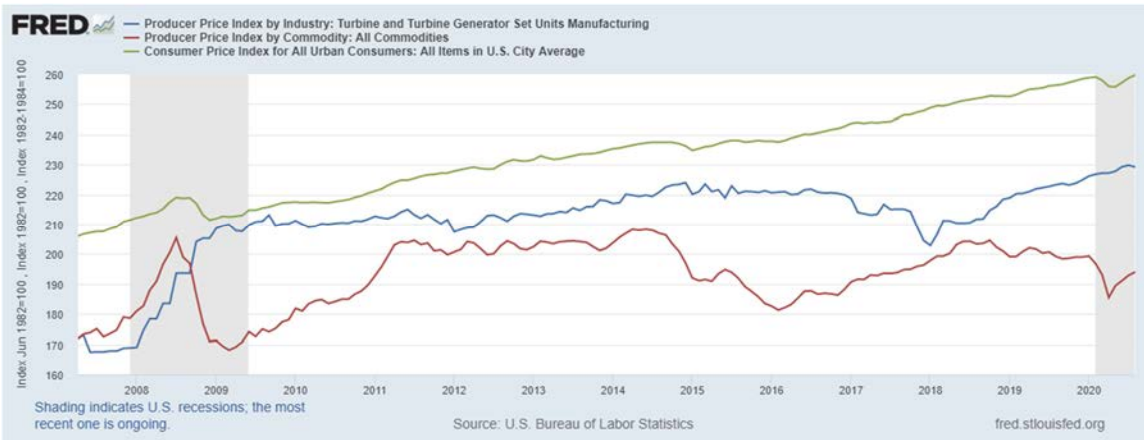


In summation, IMPA believes that any introduction of an aggressive CO2 policy, in this case via a high CO2 tax, will result in lower end-use consumption. Arguably the CAR Act, as written, could increase aggregate demand through the redistribution of wealth to lower- and middle-income families. However, this windfall to those households will likely be offset by higher utility bills. As a result, it does not seem to take a leap of faith that consumers will become even more conservation minded than today under current rules and regulations.

12.4 GENERATION AND TECHNOLOGY COSTS

Under the Green Case, IMPA assumes capital costs for technology and equipment will be largely unchanged from assumptions in the Base Case. According to data from the Federal Reserve Bank of St. Louis, Producer Prices for Turbines and Generator sets and, more broadly, for all commodity producers, have failed to maintain pricing power since "The Great Recession" of 2008.

Figure 54 Green Case - FRED PPI



In the above chart, prices for CPI have generally trended up while producer prices for turbines and commodities have stayed relatively flat over the same period. As for renewable technology, any increases in demand for panels and inverters are likely to be met with increases in technological advancement and efficiency. Ultimately, this, in IMPA's view, leads to a net zero change in cost per installed watt for solar.

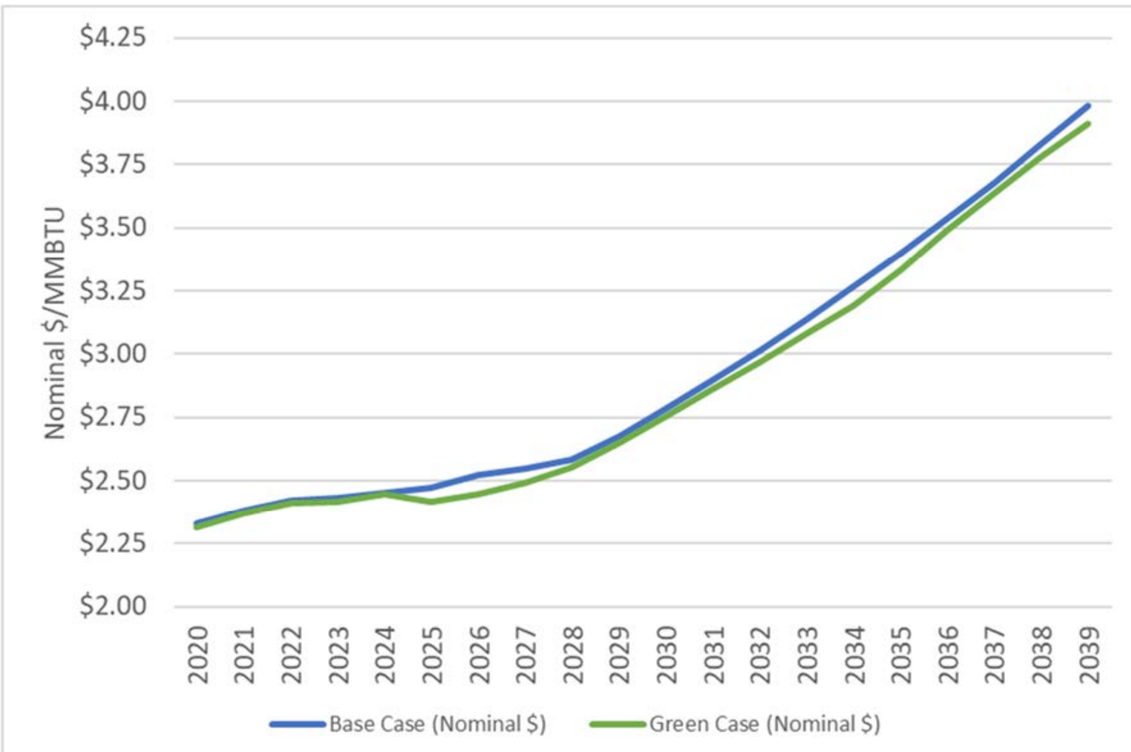
12.5 FUELS

Natural gas pricing represents a challenge as a massive shift towards lower carbon resources would lower demand for natural gas, yet a transition towards that world would no doubt require dispatchable resources to make up for the intermittency of renewable resources.

For the Green Case forecast, IMPA relied on the differences between EIA's base case forecast and their "Green" case which assumes a 50% renewable portfolio standard. These differences between the EIA's base case and green case were then applied to the IMPA Base Case for natural gas (i.e., the Henry Hub forward curve).

As illustrated in the chart below, the differences are negligible.

Figure 55 Green Case - Henry Hub Natural Gas Prices



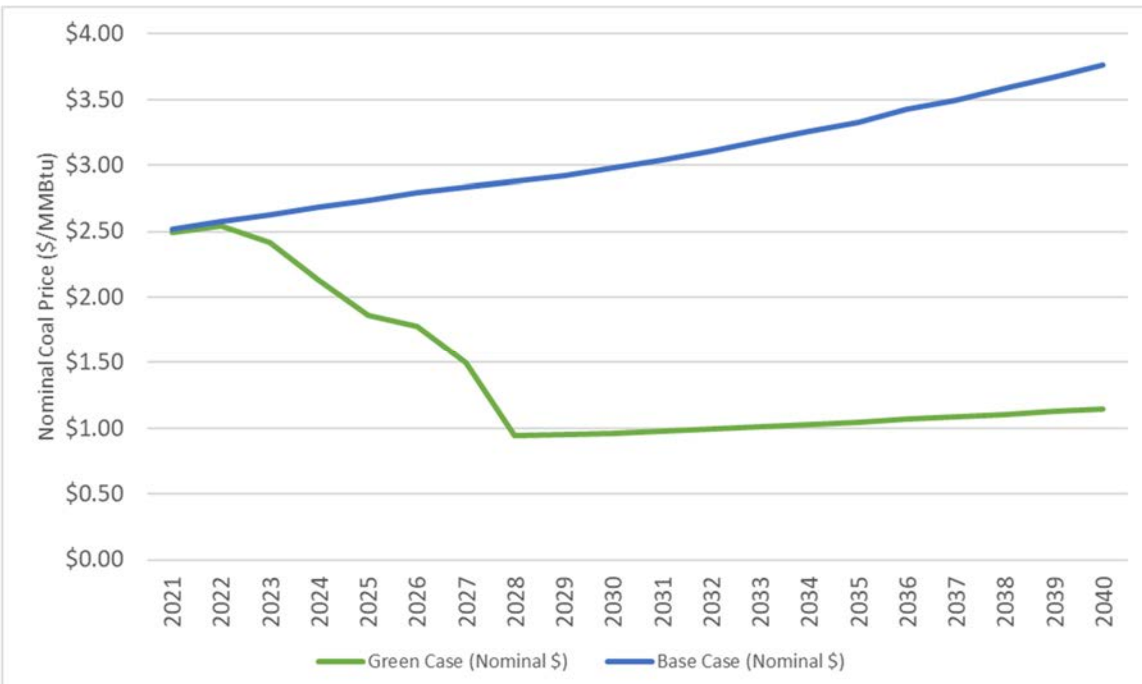
Ultimately, the currently oversupplied US natural gas market may be able to absorb increased utility demand as renewable penetration may lessen expected natural gas capacity additions. In addition, in a green world, vast installations of renewable resources may stymie around the clock natural gas demand, resulting in natural gas demand that is highly sensitive to hourly swings in renewable generation.

In contrast to technology and capital costs, IMPA's green case for fuels assumes a rapid drop in demand for steam coal. To form this forecast, IMPA relies on coal forecasts from JD Energy, Inc. In JD Energy's Green Case coal forecast, JD Energy, like IMPA, views a Green future as one that is committed to moving away from coal as a fuel for the supply of electricity. JD Energy projects coal prices in all major basins in a green world to reach $0 by 2028.

IMPA then blended this forecast into the nominal base case coal price forecast.

The chart below illustrates IMPA's forecasts for the Green Case as well as the Base Case for comparison.

Figure 56 Green Case – Coal Prices



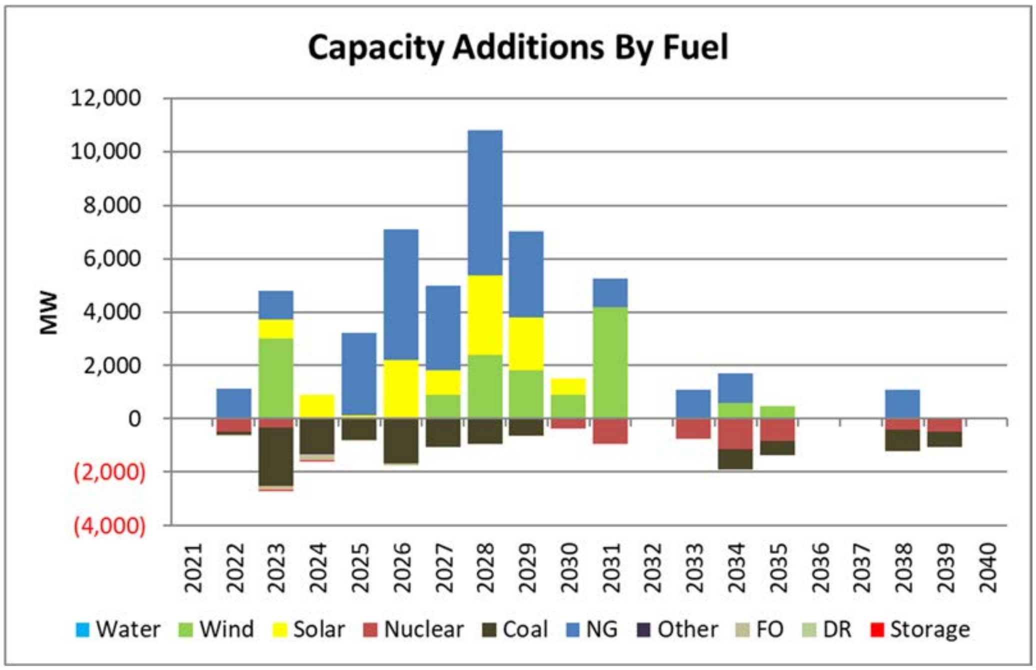
The sharp decline over the first eight years reflects the fundamentals of an abundant yet unwanted/unneeded fuel source. Less pessimistic than the JD Energy Green forecast, IMPA predicts at least some demand from legacy contract supplies and possibly some export demand.

12.6 Market Expansion

As in the base case, IMPA took the underlying assumptions set out in the Green Case in the previous section and allowed Aurora to create a capacity expansion plan that was able to maintain required reserve margins at the lowest system cost. As a static assumption, it should be noted that IMPA kept announced retirements from the base case in the Green Case.

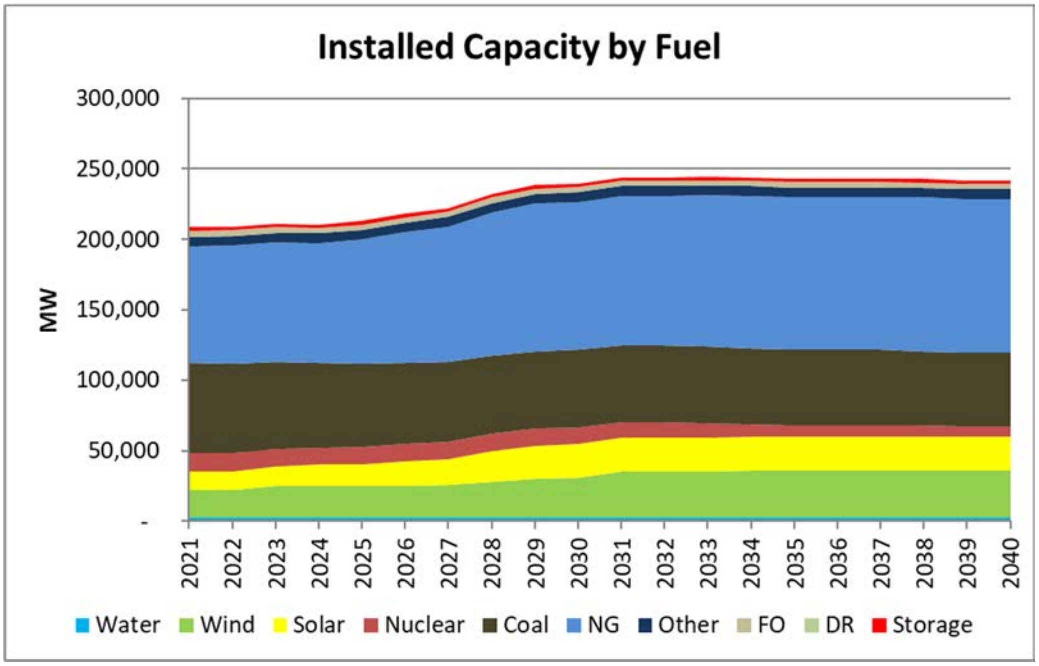
The chart below illustrates the year over year changes in capacity additions and retirements in the MISO market under the green case assumptions. Notably, the green case sees considerably more wind capacity installed when compared to the base case. The chart below illustrates the year over year changes in the capacity additions by fuel.

Figure 57 Green Case – MISO Net Capacity Additions by Fuel



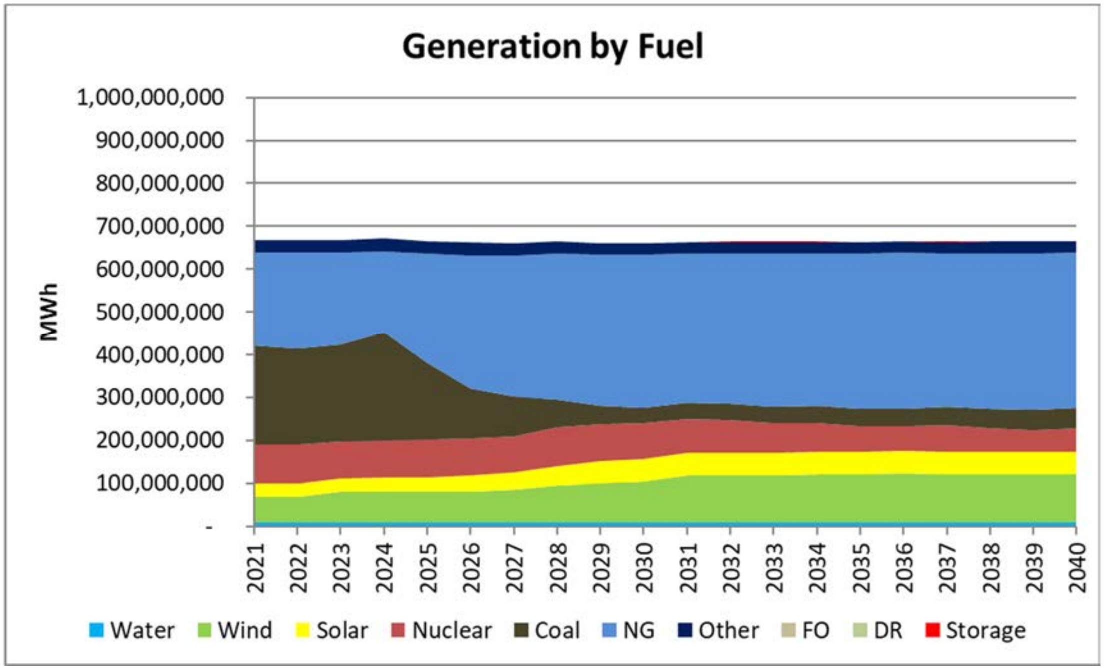
Also notable is the relative lack of outright retirements in the green case. This is being driven by coal retaining some value as a seasonal peaking resource. The following chart illustrates MISO installed capacity by fuel. Renewables and natural gas claim most of the increased capacity installations while coal remains somewhat stable after the initial retirements.

Figure 58 Green Case – MISO Installed Capacity by Fuel



Coal is projected to lose the most is in energy production, as illustrated in the chart below. The impacts of an initial $15/ton CO2 tax become apparent in 2025 when the tax is assumed to be implemented. Additional $10/ton increases in subsequent years drives coal generation even lower.

Figure 59 Green Case – MISO Generation by Fuel

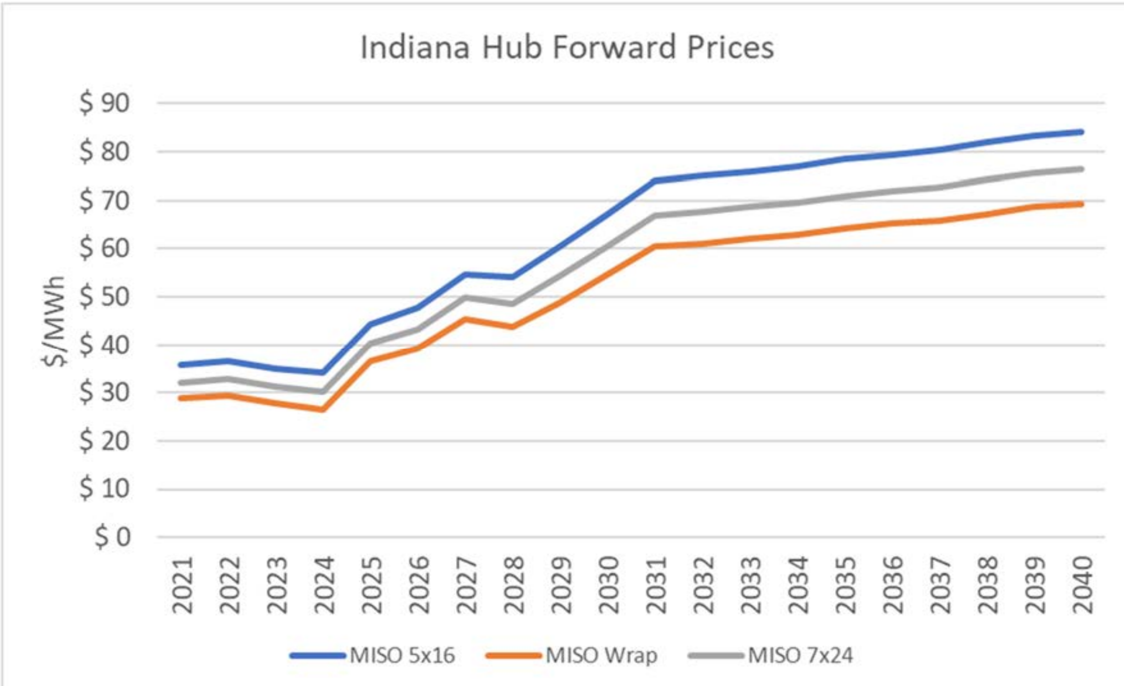


Coal still manages to cover some of fixed cost via capacity revenues and a small portion of energy market revenues to remain in the system; however, the system then finds itself short energy and is required to rebalance its energy supply portfolio by building wind (a comparatively energy rich renewable resource), solar and combined cycles.

MISO Market Prices

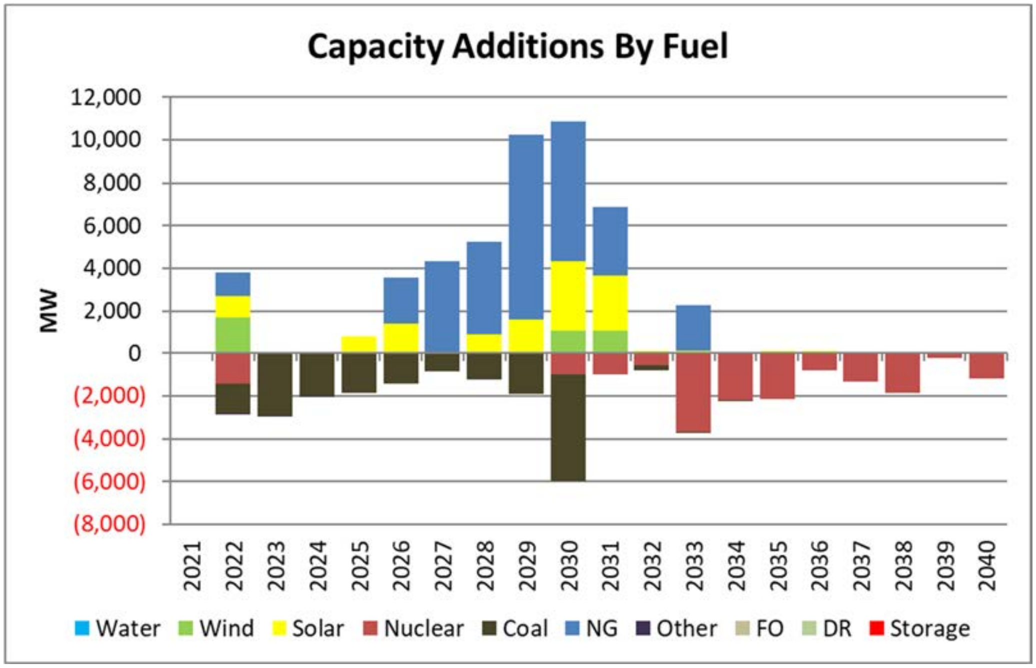
The table below illustrates prices at Indiana Hub under the assumed Green Case build plan. There is a noticeable increase first in 2025 when CO2 prices become effective at $15/ton. These increases are followed by additional $10/ton per year increases until plateauing at $75/ton in 2031.

Figure 60 Green Case – Indiana Hub Prices



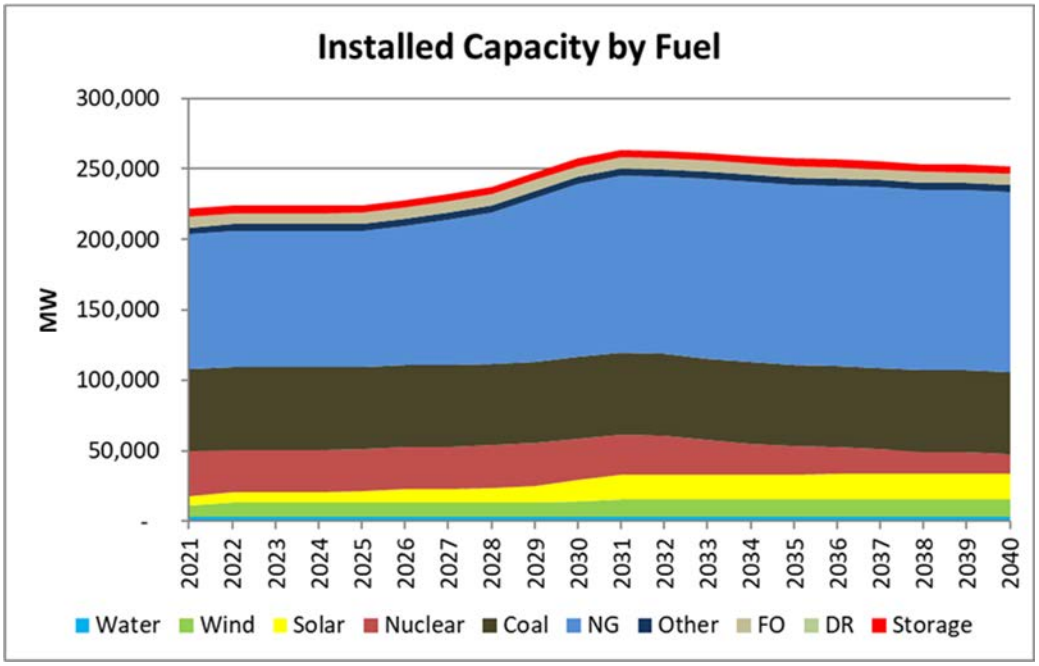
The build in PJM under the Green Case assumptions is similar to MISO with mostly natural gas combined cycles being built and with solar being favored over wind. Similar to the base case, PJM has little need in the short term for new generating capacity, however there is an initial expansion of renewable resources as the window for tax credit expires. The chart below illustrates the year over year change in capacity additions in PJM.

Figure 61 Green Case – PJM Net Capacity Additions by Fuel



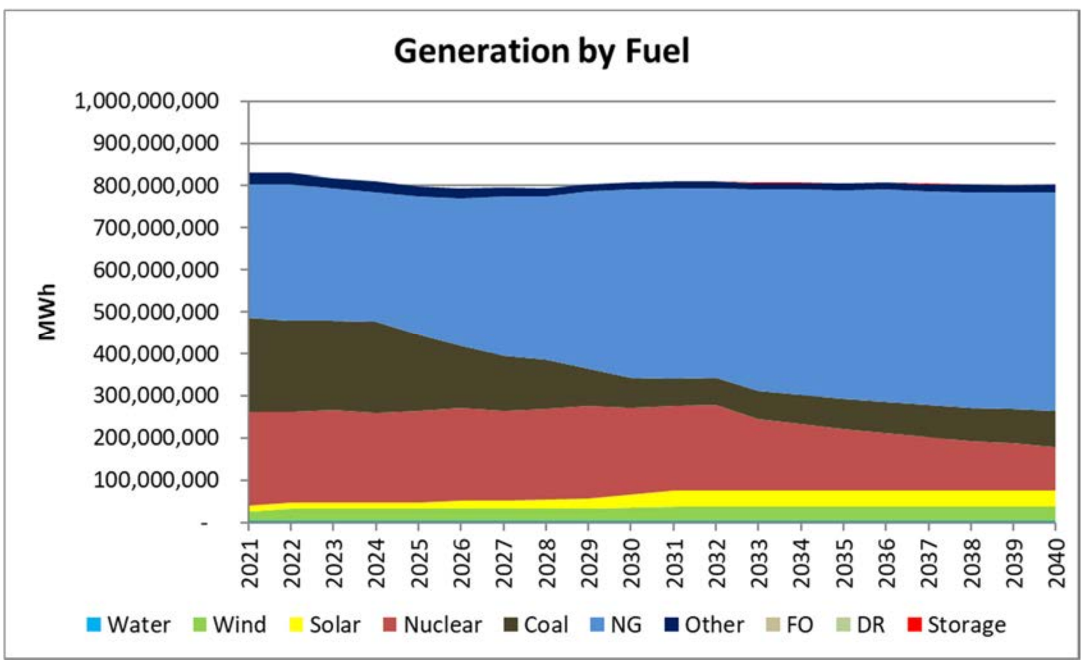
New capacity favors natural gas and solar, while coal and nuclear are the primary sources of retired capacity. IMPA assumes nuclear units will not pursue additional license extensions.

Figure 62 Green Case – PJM installed Capacity by Fuel



However, on actual generation, solar and natural gas see increases while coal generation declines dramatically.

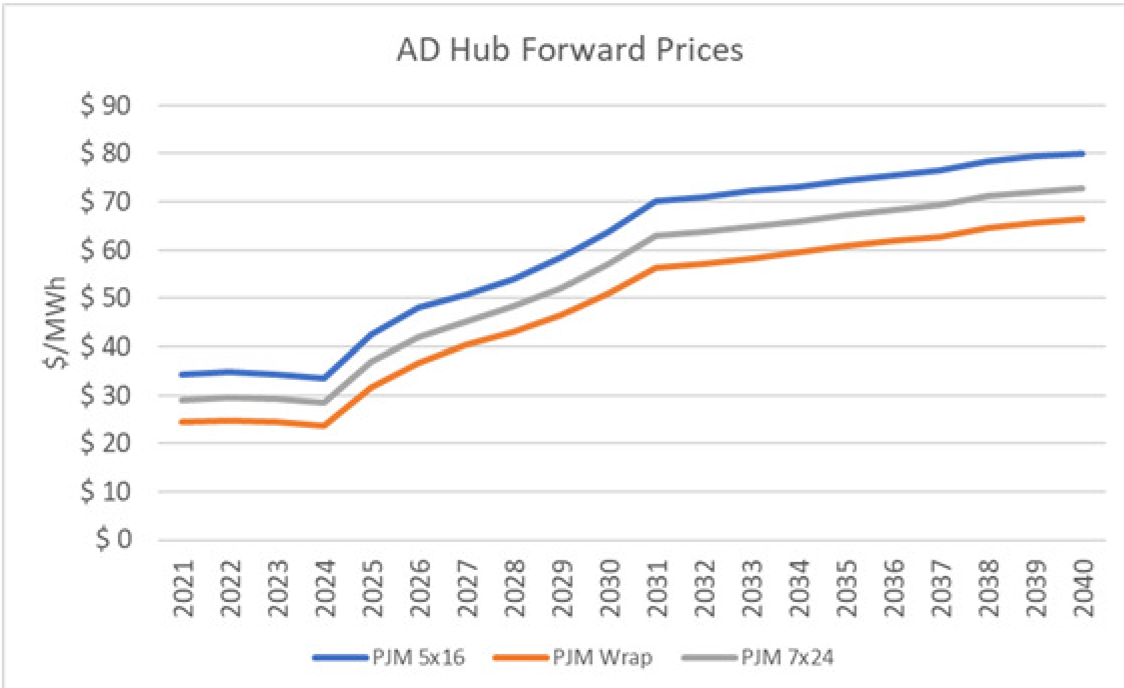
Figure 63 Green Case – PJM Generation by Fuel



PJM Market Prices

The table below illustrates prices at AD Hub under the assumed Green Case build plan. Given AD Hub's proximity to Indiana Hub, there is not much deviation from Indiana Hub pricing.

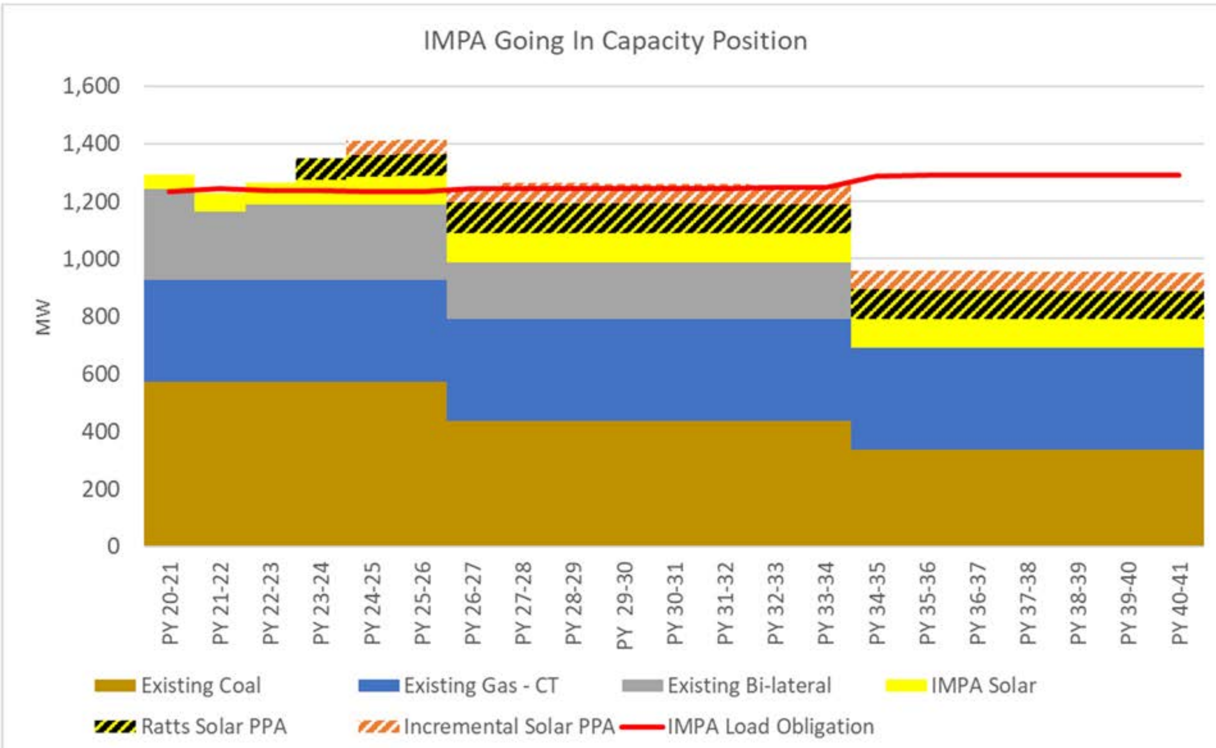
Figure 64 Green Case – AD Hub Prices



12.7 Portfolio Selection

Identical to the Base Case process, the IMPA portfolio is optimized for cost within the market expansion that was created. In this case, the portfolio is deterministically optimized around a markedly green world. The going in position, shown below, illustrates needs given the expectation of flat load growth under a green world.

Figure 65 Green Case – Going In Capacity Position



The key difference between the base case and the green case in optimization of the portfolio is that while loads are presumed to be lower, thus lowering the capacity requirement, energy needs are actually higher due to the non-retirement of generally out-of-the money coal resources.

Nevertheless, IMPA, in a green world, would need to replace capacity from expiring bilateral contracts, the retirements of Gibson 5 and Whitewater Valley Station, and finally the expiration of the AEP contract. In this case, the optimal capacity additions include a Pre-ITC expiration solar project, ideally in MISO Z6, 150 MW of MISO wind and roughly 214 MW of natural gas combined cycle. This optimization would make IMPA appear long capacity but would also replace lost generation from infrequently dispatched coal units. In PJM, the AEP and Whitewater Valley capacity is replaced with roughly 170 MW of natural gas combined cycle, 100 MW of solar, and 150 MW of wind.

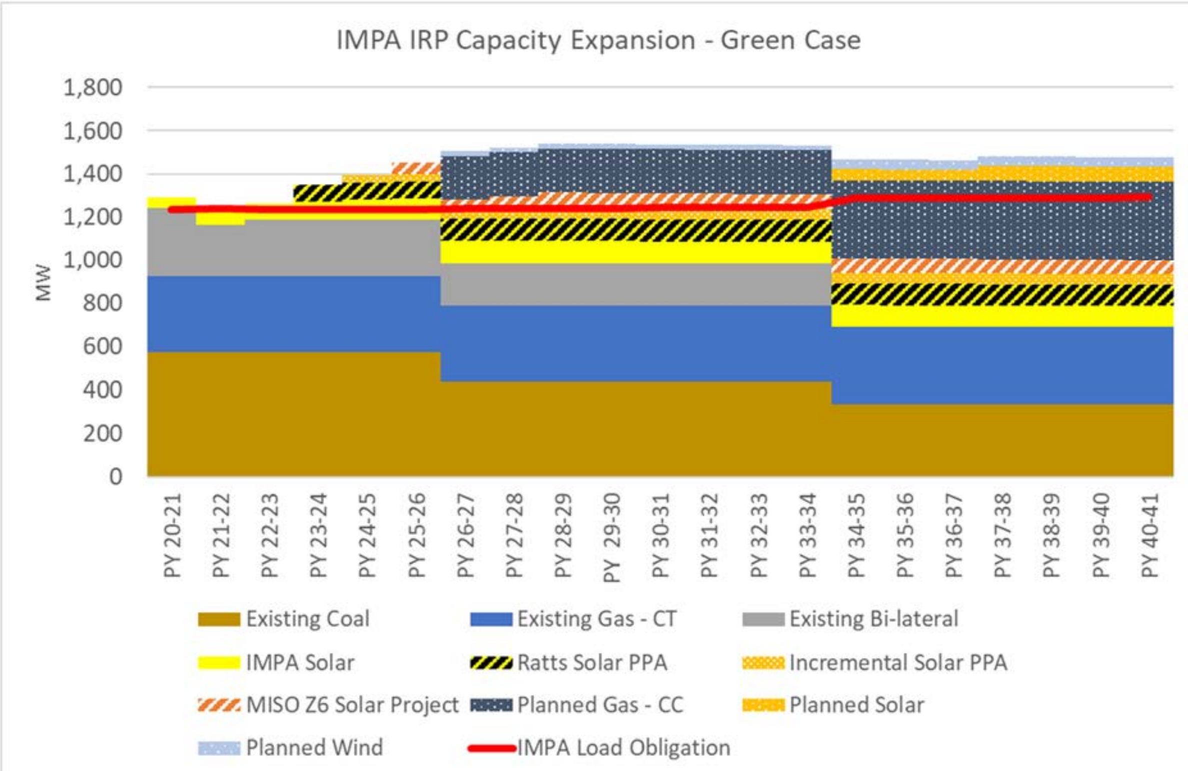
The table below illustrates a year-by-year summary of capacity additions and withdrawals under the green case.

Table 16 Green Case Expansion Plan

IMPA Green Case Plan - ICAP Capacity (Summer Ratings)					
Planning Year	MW Withdrawn	MW Withdrawn Notes	MW Capacity Added	MW Capacity Added Notes	Net Capacity Added/(Withdrawn)
PY 21-22	-100	Duke Option Expires	72	Increase in Bilateral Contract Qty, IMPA Solar	-28
PY 22-23			111	Increase in Bilateral Contract Qty + IMPA Solar + Alta Farms Wind PPA (Energy Only)	111
PY 23-24			161	Ratts Solar PPA + IMPA Solar	161
PY 24-25			111	Solar PPA (currently in negotiation) + IMPA Solar	111
PY 25-26			111	MISO Z6 Solar Project + IMPA Solar	111
PY 26-27	-231	Gibson #5 Retirement/Bilateral Capacity Expiration	375	Planned Natural Gas Combined Cycle (214 MW)+ wind project (150) + IMPA Solar	144
PY 27-28					
PY 28-29					
PY 29-30					
PY 30-31					
PY 31-32					
PY 32-33					
PY 33-34					
PY 34-35	-286	AEP Contract Expiration/WWVS Retirement	417	Planned NG Combined Cycle + 100 MW Solar + 150 MW Wind	131
PY 35-36					
PY 36-37					
PY 37-38					
PY 38-39					
PY 39-40					
PY 40-41					

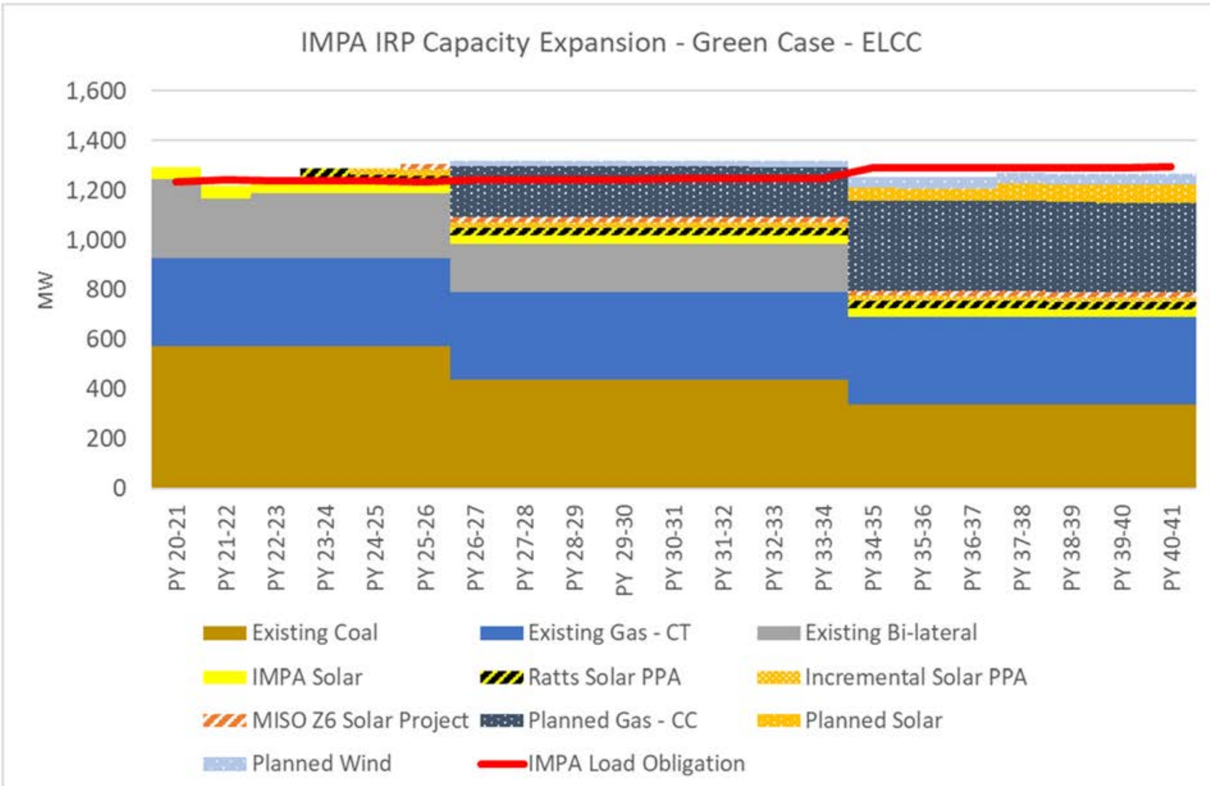
The chart below illustrates IMPA's capacity position after optimization and assuming standard renewable capacity credits.

Figure 66 Green Case – Expansion Plan



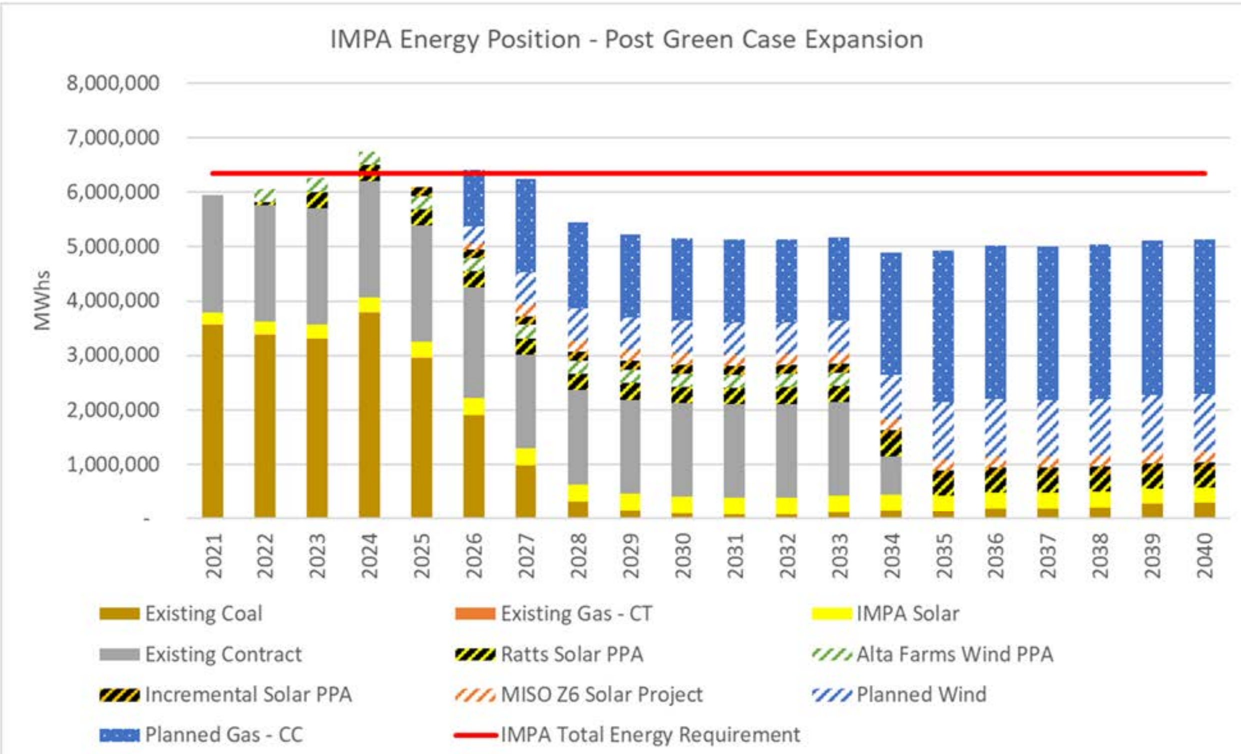
As discussed in the Base Case section, ISO/RTO markets have expressed concern with the impact higher renewable penetration will have on system reliability. Once renewable capacity credit is adjusted for its "Effective Load Carrying Capability" IMPA's projected capacity position flattens out, as shown in the chart below.

Figure 67 Green Case – Expansion Plan with Adjusted ELCC



The chart below illustrates IMPA's projected energy needs after optimization. Over time, the increasingly large CO2 price gradually drives coal generation to less than 5% of portfolio generation. Generation from resources acquired in the optimization replaces the displaced coal generation. A bulk of the new generation stems from the addition of natural gas combined cycle generation in both the MISO and PJM portfolios, with solar and wind filling in the balance.

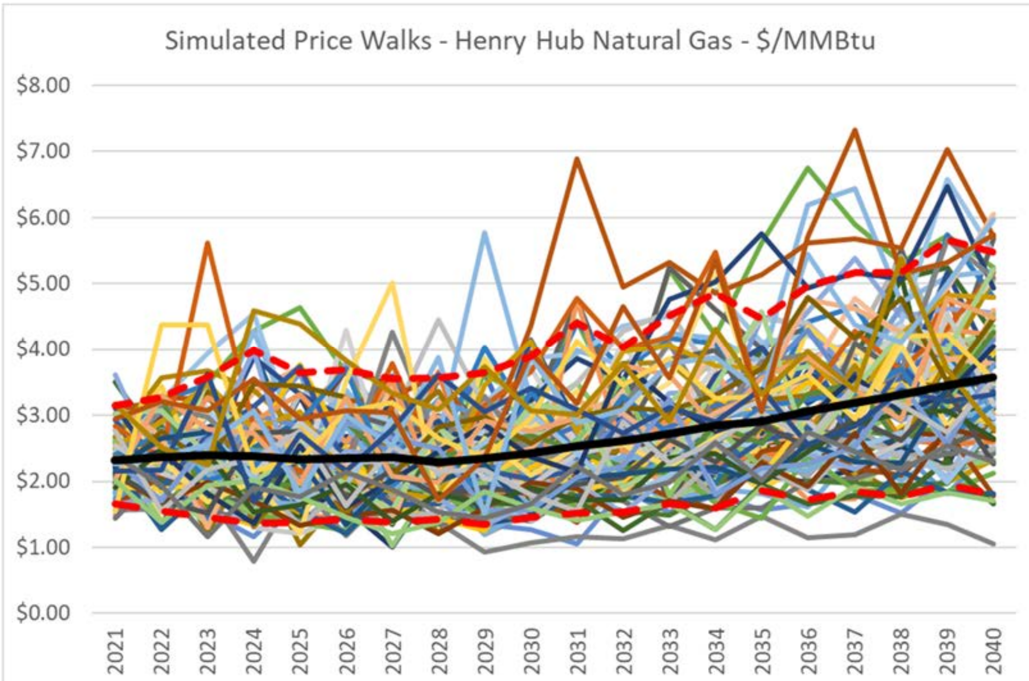
Figure 68 Green Case – Post Expansion Energy Position



12.8 STOCHASTICS

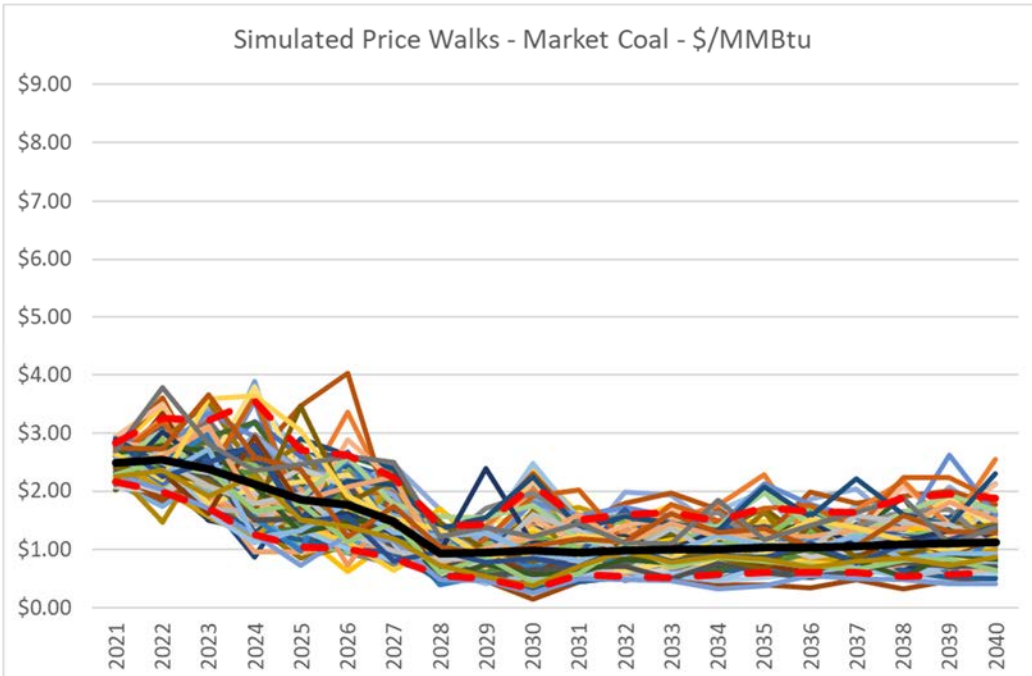
Key parameter estimates for the Green Case stochastics is unchanged from the Base Case. However, the expected values of those underlying risk variables (e.g., natural gas), changes to reflect the underlying Green Case assumptions. The chart below illustrates the price walks for natural gas at Henry Hub.

Figure 69 Green Case – Henry Hub Gas Simulated Price Walks



As shown, the walks are similar to the Base Case price walks with only a slight difference at the mean. Simulated coal price walks, however, differ considerably, largely due to the lower overall expectation in forward prices.

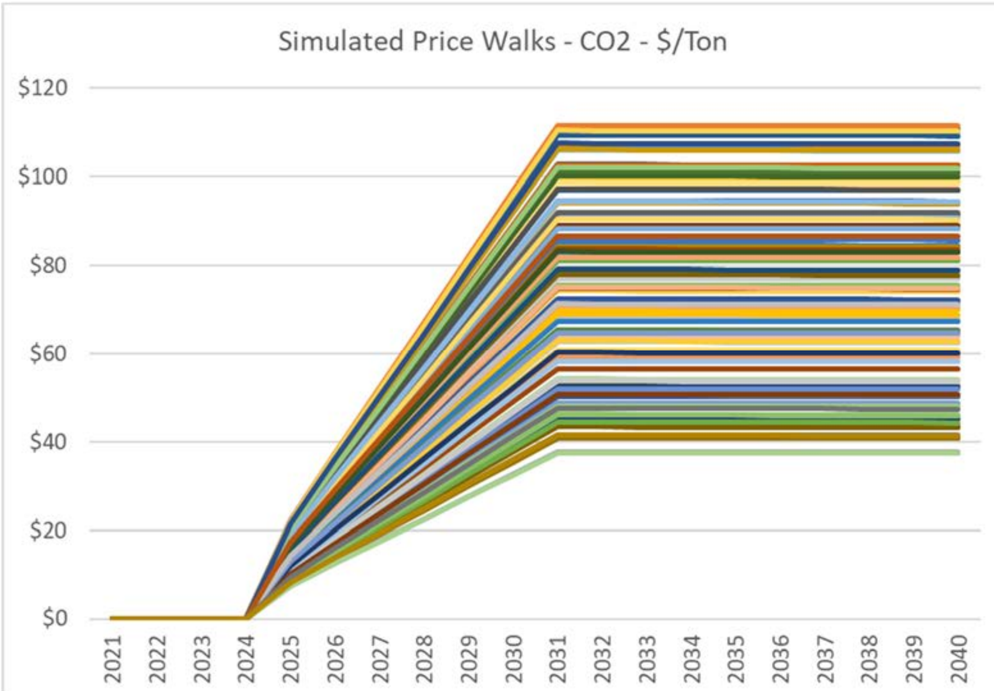
Figure 70 Green Case - Market Coal Simulated Price Walks



In iteration-by-iteration detail, there is never a draw where the coal price exceeds natural gas prices after 2029. Despite this, the stochastic draws for CO_2 pricing ensures that despite a low coal price, the additional cost of CO_2 makes coal uncompetitive.

The iteration detail for CO2 pricing is shown below.

Figure 71 Green Case – CO2 Simulated Prices Walks

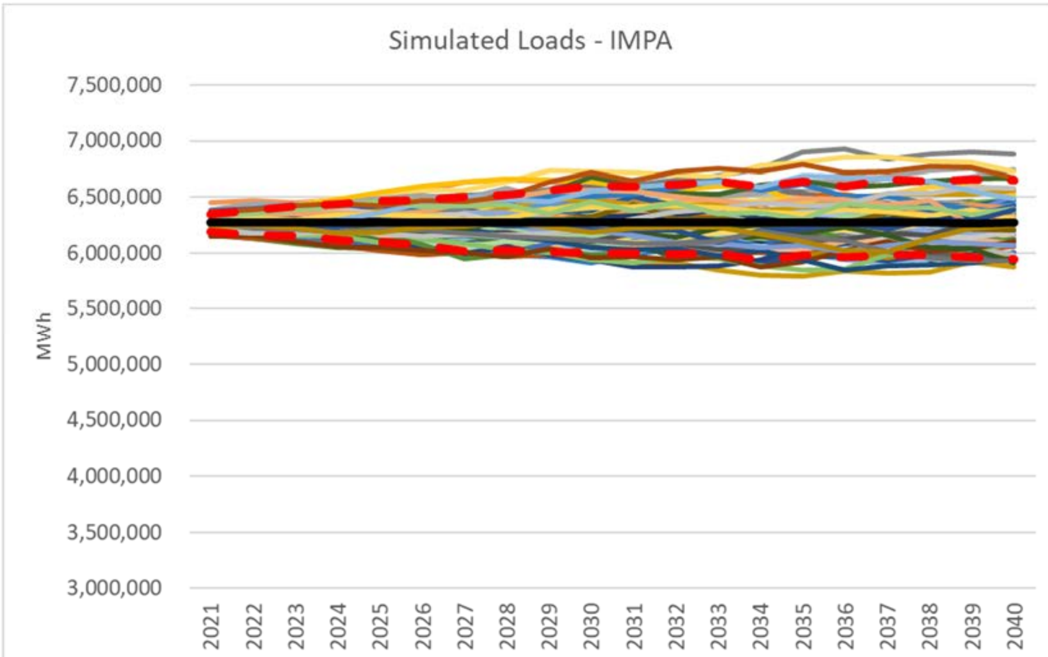


Under the Green Case, the expected value for CO2 starts in 2025 at $15/ton and escalates by $10/ton each year until reaching a terminal value of $75/ton in 2031. Stochastically, uncertainty around CO2 prices varies widely. Once the price reaches its zenith, the deviation around the mean at a 90% confidence interval is $33/ton.

Simulated load walks are very similar to the Base Case load walks, but around the Green Case mean loads.

The figure below illustrates the Green Case load walks.

Figure 72 Green Case – Simulated Load Walks

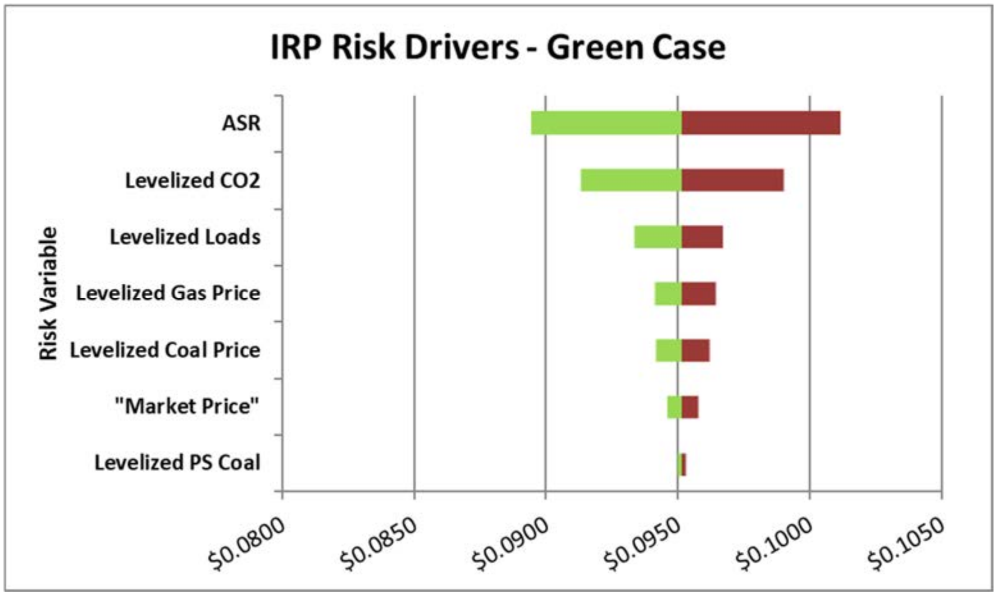


12.9 Portfolio Assessment

The IMPA Average System Rate (ASR) has an expected mean of \$.095/kWh (versus the Base Case ASR of \$.0830). More telling is the risk around this mean at the 90% confidence interval. In the Green Case portfolio, the ASR has a 5^{th} percentile ASR of \$.08949/kWh and a 95^{th} percentile ASR of \$.1011/kWh.

The risk spread between the 95^{th} percentile and mean is roughly \$.06/kWh, roughly \$.02/kWh higher than in the Base Case.

Figure 73 Green Case – Tornado Chart

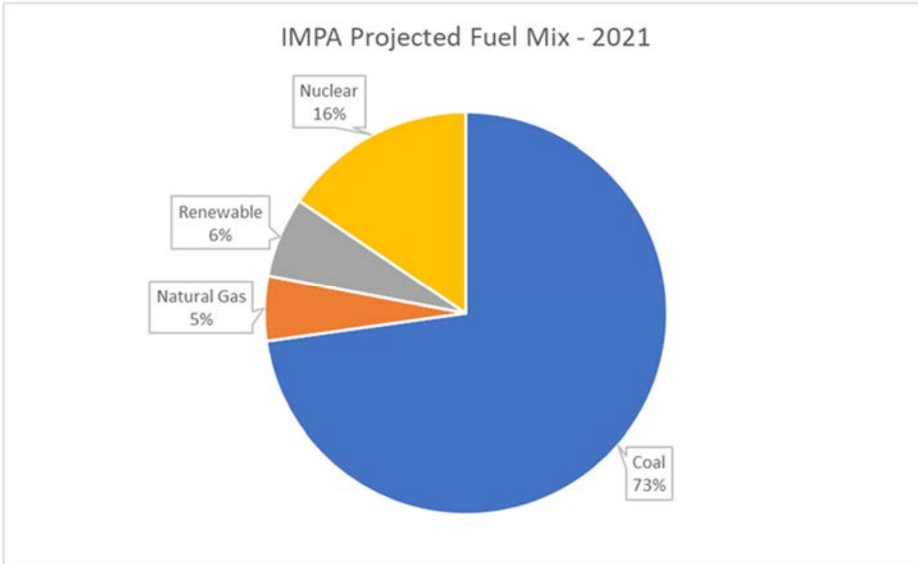


When risks within the variance of total ASR are ranked however, the risk profile changes with Levelized CO2 impacts being the largest single risk. In the base case, CO2 risk was 3^{rd}.

The only way to effectively hedge these risks is by decarbonizing the portfolio via carbon neutral sources of power supply, which the Green Case portfolio does accomplish. However, the need for replacement energy from a natural gas combined cycle increases the portfolio sensitivity to natural gas prices when compared to the Base Case, with natural gas moving up to 3^{rd} largest risk factor from 5^{th} in the Base Case.

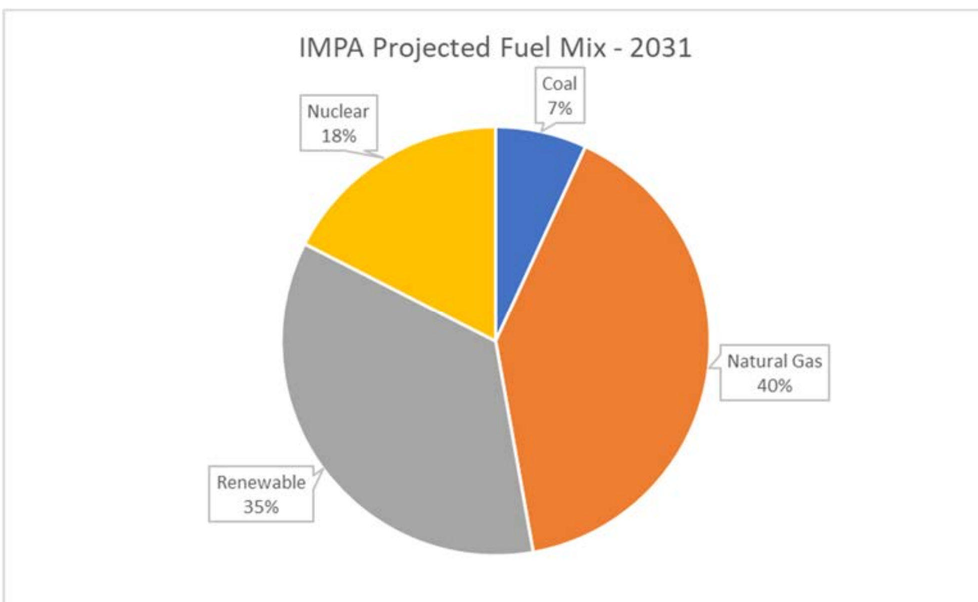
The following charts illustrate a rapidly decarbonizing IMPA power supply portfolio under the optimal mix. The projected 2021 mix remains the same as in the base case, with a bulk of generation coming from coal fired resources.

Figure 74 Green Case - 2021 Fuel Mix



However, as show below, the mix after 10 years has aggressively pivoted towards natural gas and renewables.

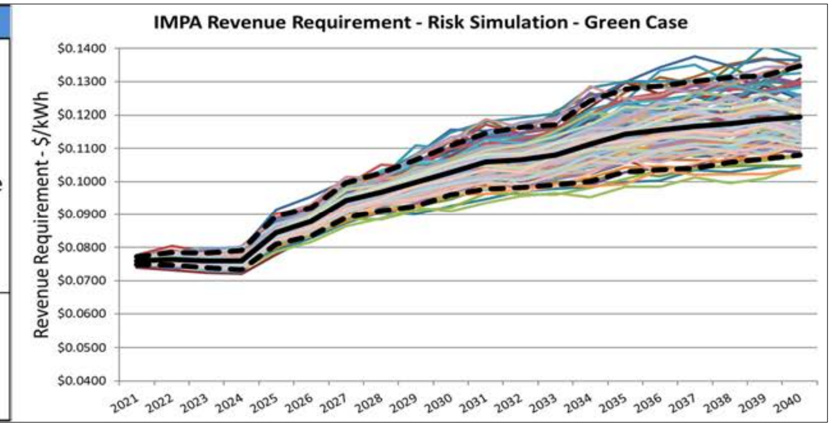
Figure 75 Green Case – 2031 Fuel Mix



12.10 GREEN CASE SUMMARY

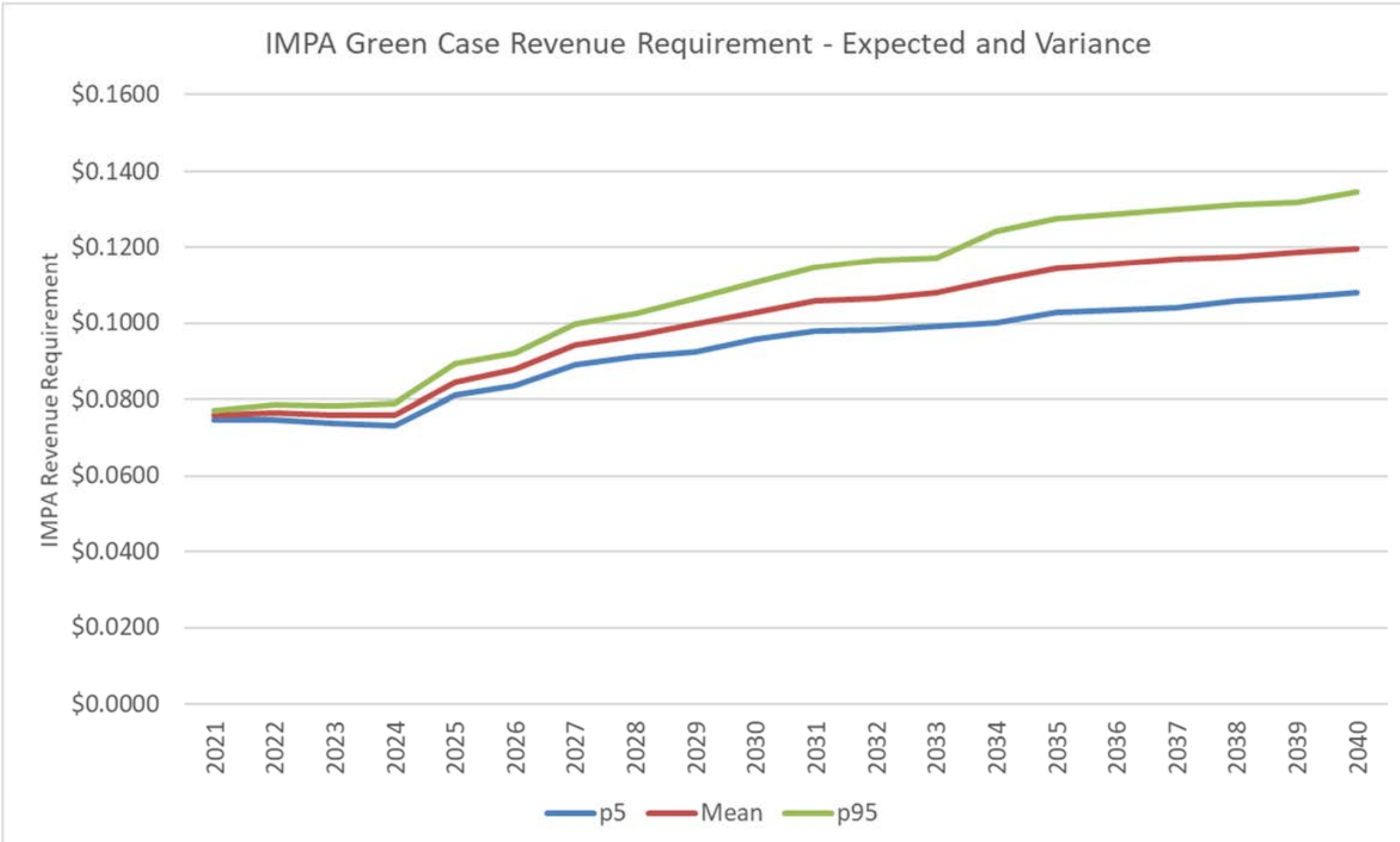
Plan Summary: In this optimization, generation retirements include Gibson 5 on 5/31/2026 (156MW) and Whitewater Valley Station on 5/31/2034 (90 MW). Over the study period, IMPA sees the net expiration of 321 MW of bilateral/full requirements capacity contracts. Planned replacements include: 100 MW of solar in PY 25-26 and 150 MW of wind and 214 MW of natural gas combined cycle in PY 26-27. In PJM, planned replacements include 167 MW of natural gas combined cycle along with 150 MW of wind and 100 MW of solar.

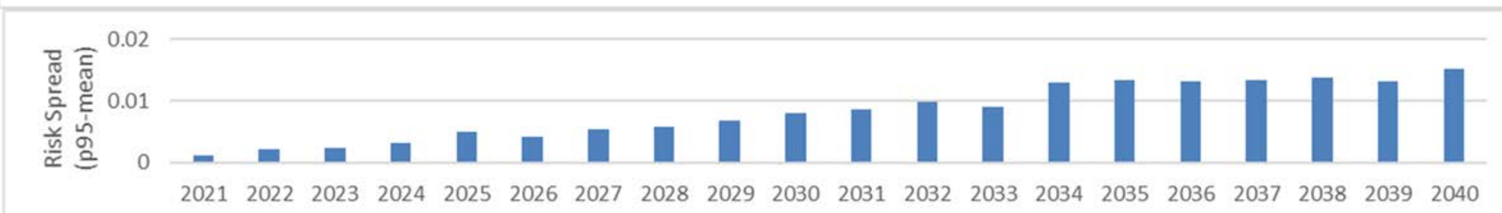
Drivers	Green Case
Economic Growth	1.8%
Capital Costs	Reference
Load Forecast	Zero Growth
Natural Gas Prices	Market x EIA Green Case Change
Coal Price	Reference less JD Energy Green Forecast Case
CO2 Policy	$15/ton esc. at $15/ton per yr.
RPS	Only extant state requiremetns
Reserve Margin	Reference Area
Asset Retirements - ICAP MW	-246
Net Market Capacity Transactions - ICAP MW	-321
Natural Gas Additions - ICAP MW	381
Renewable Additions - ICAP MW	927



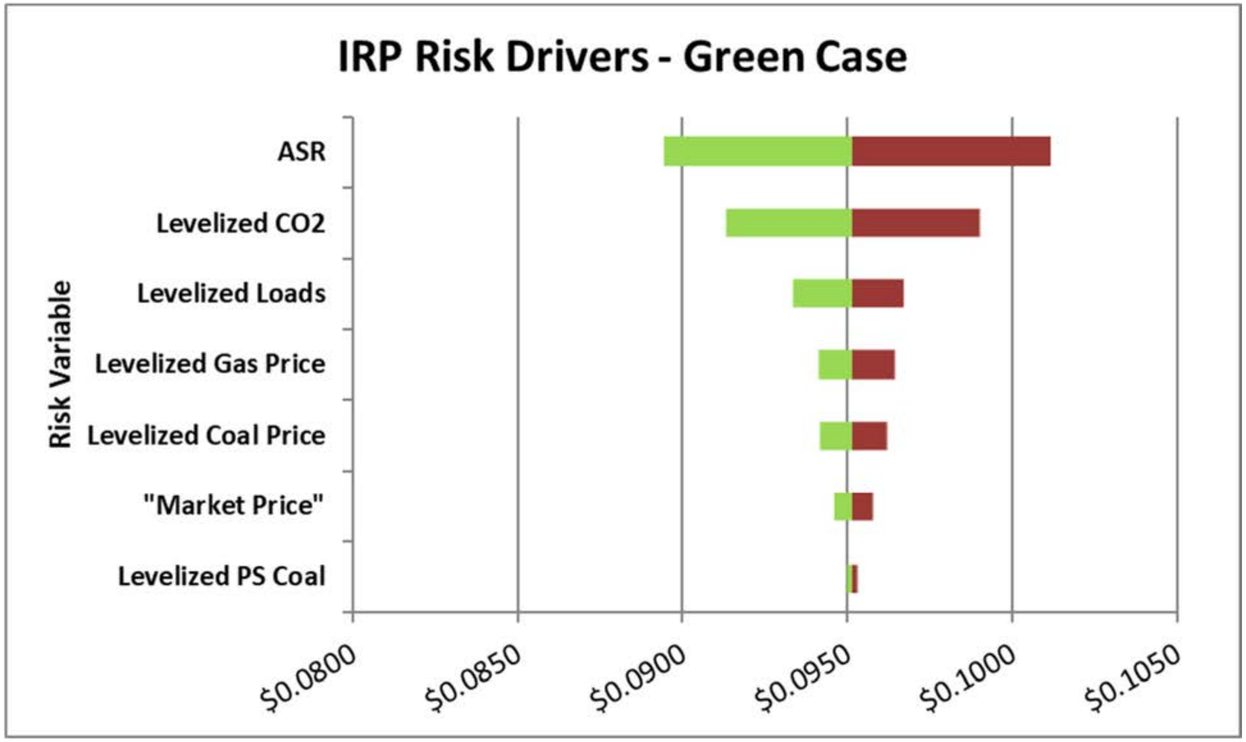
Plan Observations: Despite being long capacity, the planned expansion under the Green Case remains somewhat short energy. This is largely due to the retention of out of the money coal assets being used for capacity resource, but still needing to replace the energy lost from those resources with less carbon intensive forms of generation. The Green Case portfolio has the largest variance in revenue requirement, largely owing to uncertainty in CO2 price regimes.

Risk Profile Observations: The Green Case portfolio has the largest variance in revenue requirement, largely owing to uncertainty in CO_2 price regimes. In addition, the relatively high cost of CO_2 at the mean drives the comparatively high revenue requirement.





Tornado Chart Observations: As coal generation becomes a much smaller portion of IMPA's portfolio, risk associate with coal decline. However, the plan replaces some coal generation with a natural gas combined cycle, in addition to renewable sources. The combined cycle generation, along with uncertain market purchases around the IMPA asset base, increases exposure to CO2 prices (with market purchases having CO2 prices effectively embedded in them). Exposure to natural gas prices in increases relative to the base case due to the addition of the combined cycles as well, owning to their operation as baseload assets in the model runs.



13 HIGH GROWTH CASE

13.1 IRP Scenario Development

This section sets the groundwork for the assumptions used to construct the High Growth Case, condensed where possible. This section will generally follow the same format as the prior sections.

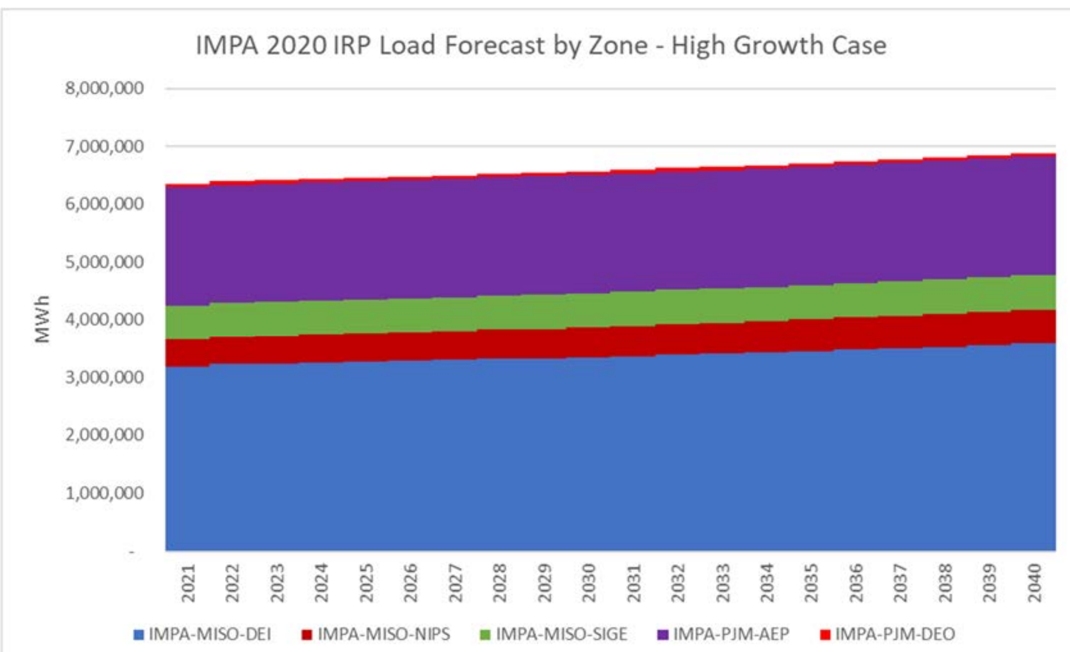
13.2 Carbon Policy

The underlying assumptions for the High Growth Case attempt to reflect a world in which policies pursued are tilted toward "economic growth at all costs." Consequently, IMPA assumes in this world that CO2 policy of any kind fails to materialize, leading to a $0/ton CO2 price.

13.3 Load Forecasts – IMPA and ISOs/RTOs

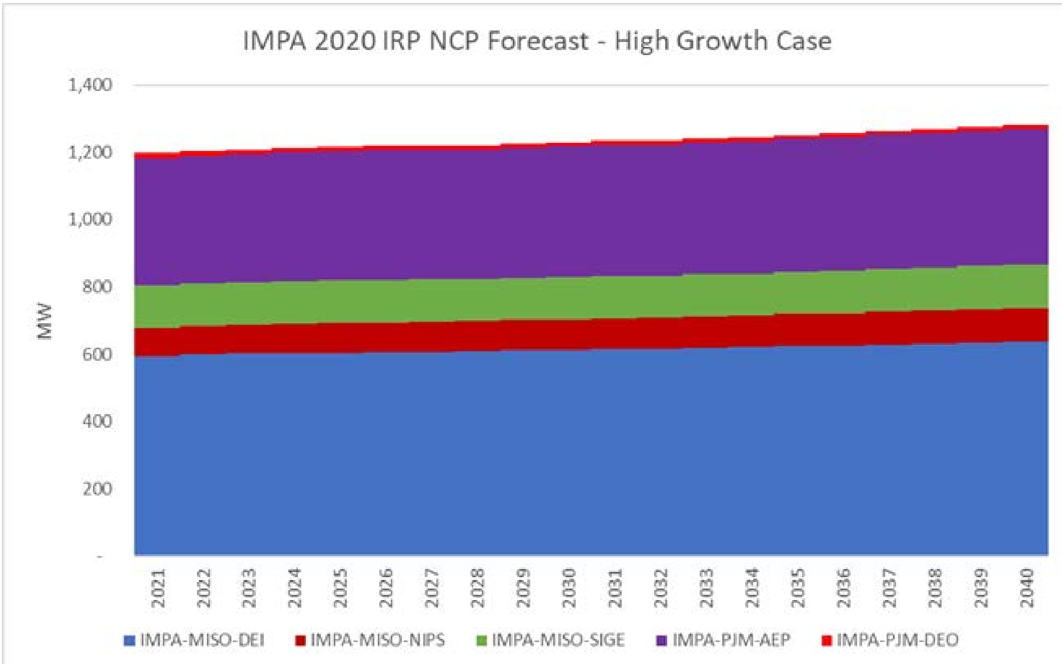
Generally speaking, the utility industry has been seeing loads well under that of broader economic growth. Specific to IMPA, load growth is somewhat constrained by a fixed geographic territory. Population growth in IMPA's member communities has been historically low. Assuming economic growth does resume, and some catalyst arises to spur consumption growth (i.e. EV charging), IMPA estimates that "high" growth is around 1% higher than the base case. For reference, please refer to Section 6 where weather adjusted y/y changes in load are illustrated. Absent a sharp rebound post "Great Recession" it is somewhat rare for IMPA to see 1% y/y growth in load. The chart below illustrates the energy forecast under the High Growth Case.

Figure 76 High Growth Case - IMPA Energy Forecast



IMPA assumes peak loads move in lockstep with the underlying energy forecast, illustrated below.

Figure 77 High Growth Case - IMPA Demand Forecast



In a high growth world, it is likely that the load impacts felt by the broader market would be higher than IMPA due to a wider geographic footprint and a wider distribution of incomes. These factors would presumably lead to more opportunities for economic growth, EV adoption, etc. For both PJM and MISO markets, IMPA assumes those markets will average 1.1% growth in energy and peak demand. The following charts illustrates the MISO and PJM load forecasts.

Figure 78 High Growth Case – MISO Energy Forecast

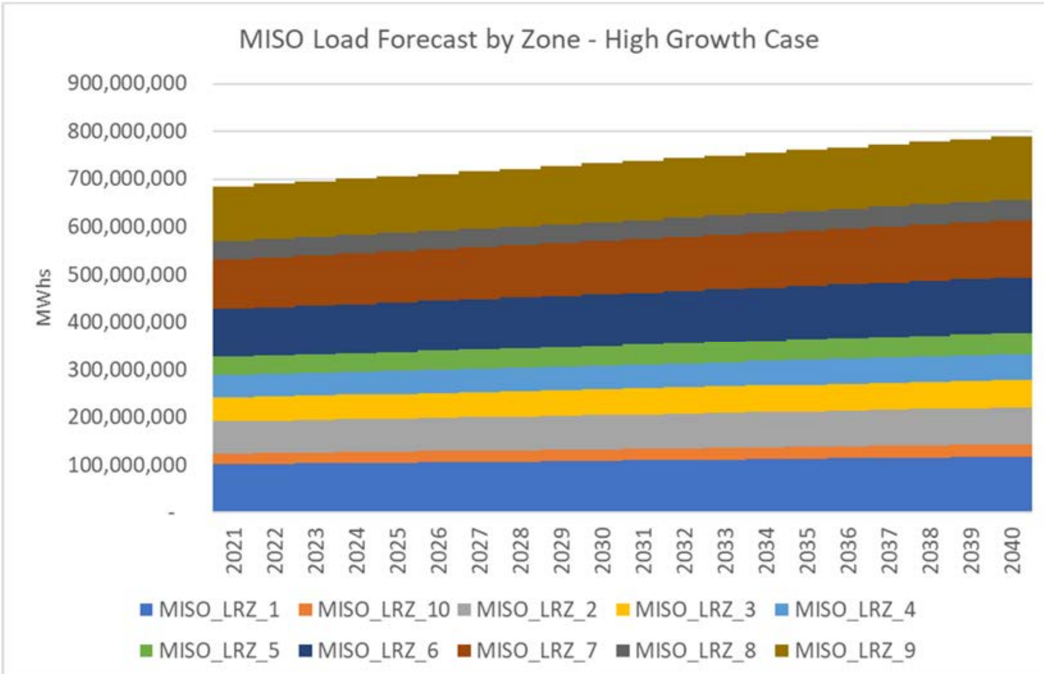


Figure 79 High Growth Case – MISO Demand Forecast

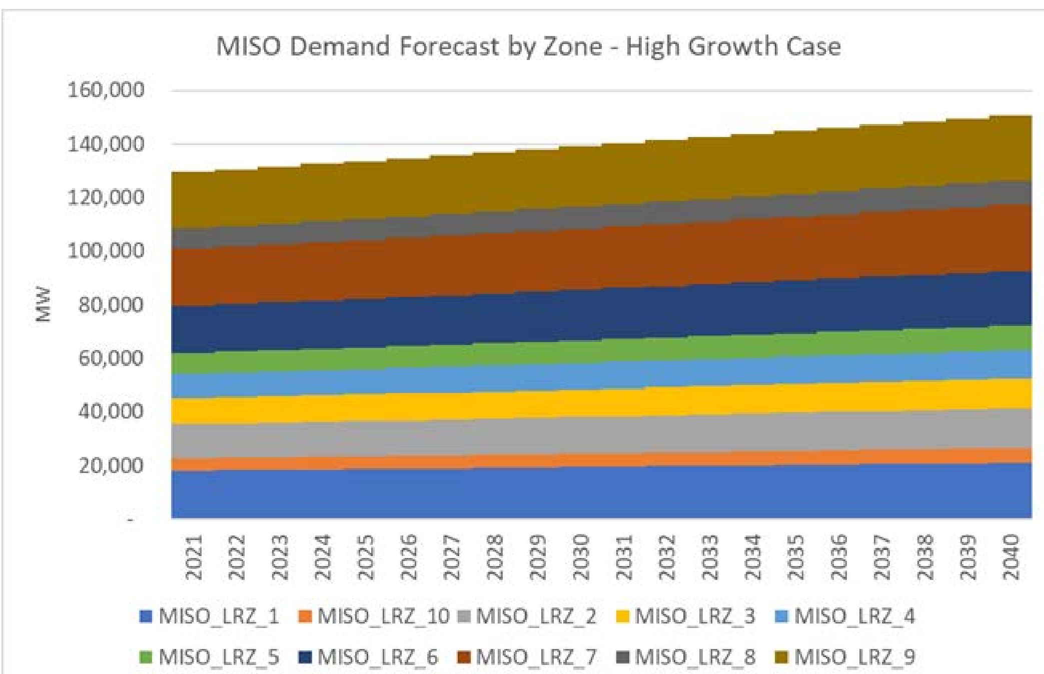


Figure 80 High Growth Case – PJM Energy Forecast

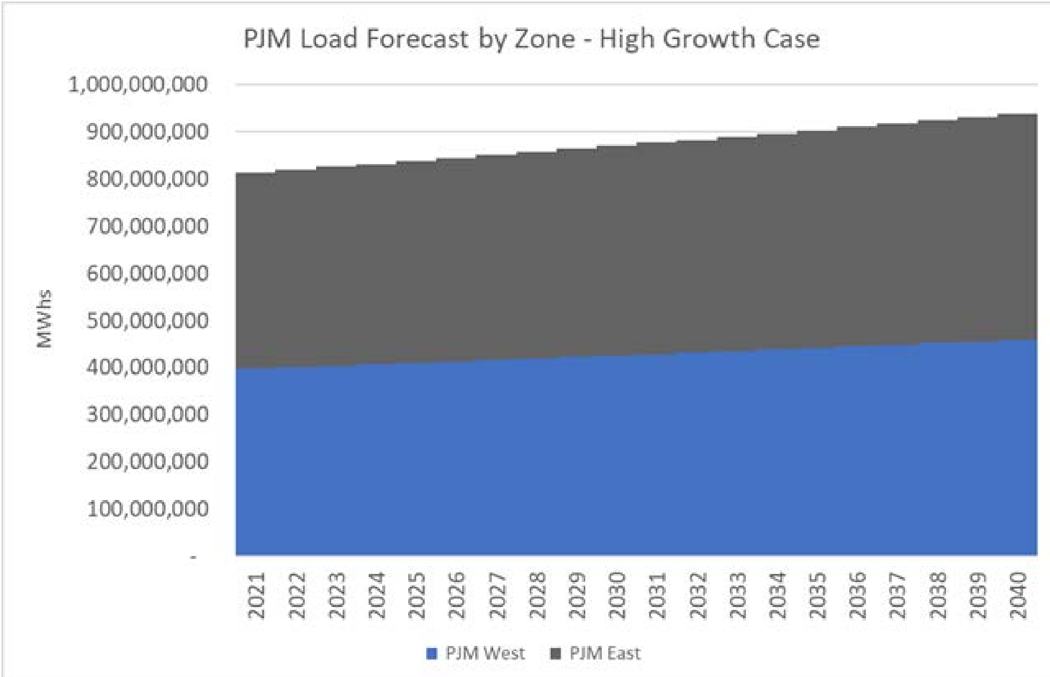
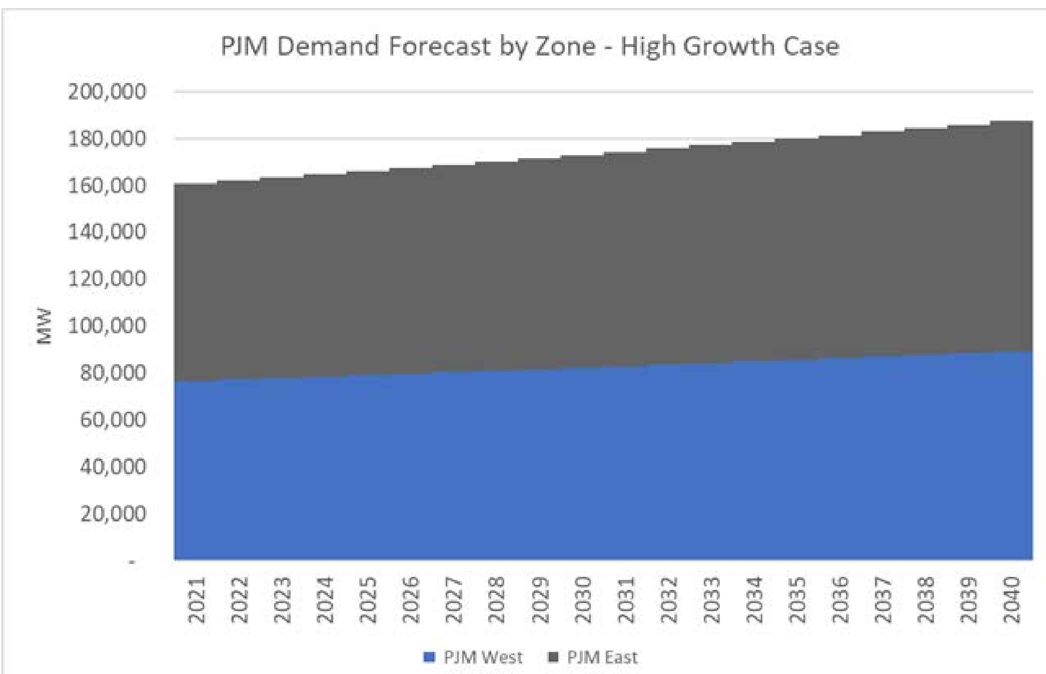


Figure 81 High Growth Case – PJM Demand Forecast



13.4 Generation and Technology Costs

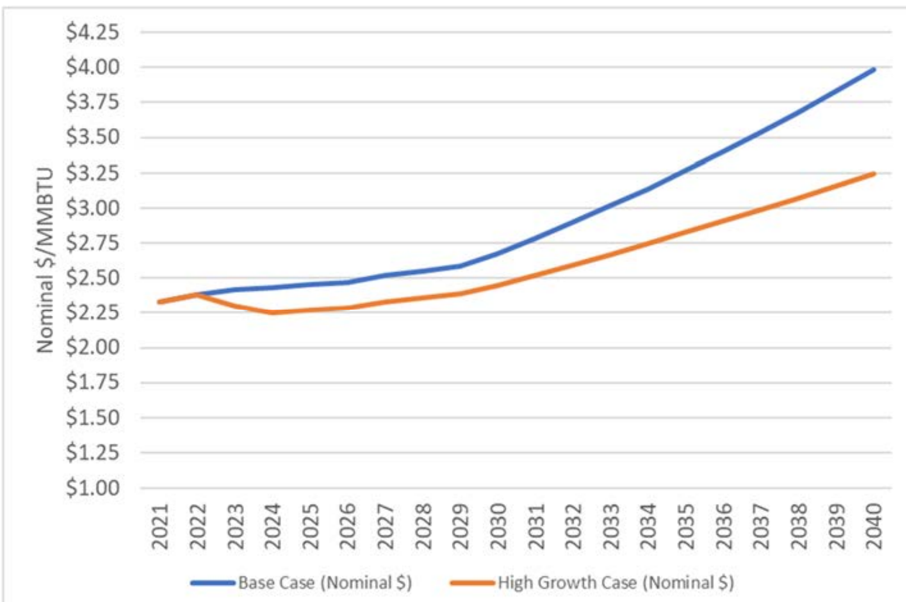
As was discussed in the Green Case, generation equipment suppliers have seen relatively low pricing power when compared to broader levels of inflation and economic growth. Consequently, IMPA keeps generation and technology costs unchanged in the High Growth Case.

13.5 Fuels

IMPA's underlying assumptions for the high growth case assume little additional regulation that would inhibit additional exploration and production of natural gas. In addition, it is assumed additional technology gains in resource extraction lower the extraction cost for natural gas.

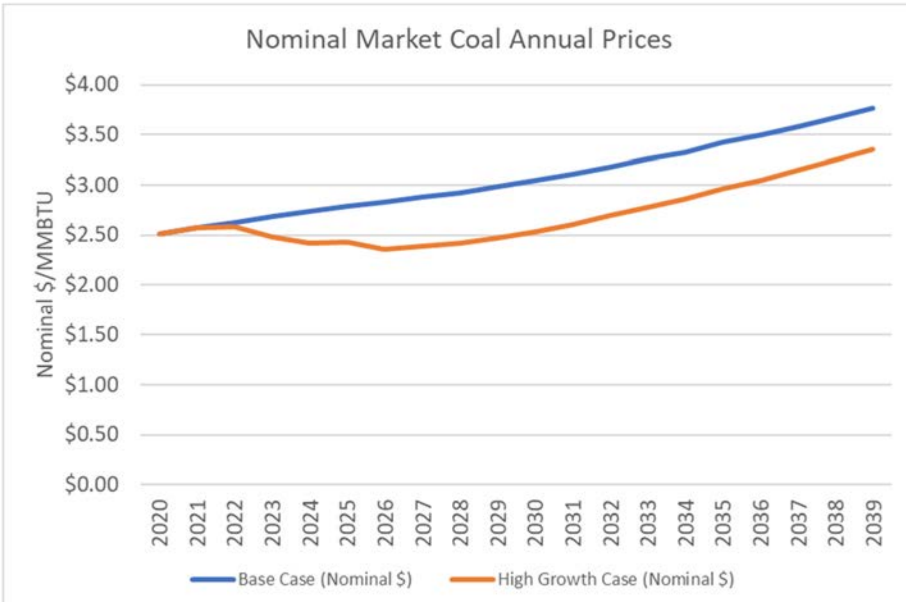
From a supply standpoint, this would exacerbate the continued oversupply of natural gas. As a result, the forward price assumption for natural gas is assumed to track with the futures market (i.e. the base case) in the near term before deviating in 2023. Prices remain suppressed but generally track higher from 2023 onward.

Figure 82 High Growth Case - Henry Hub Natural Gas Prices



With respect to coal pricing, IMPA expects shifts to coal markets to mimic natural gas with additional supply coming to market via reduced regulation. Additional demand will remain muted however, given the number of announced near term coal retirements.

Figure 83 High Growth Case - Coal Prices

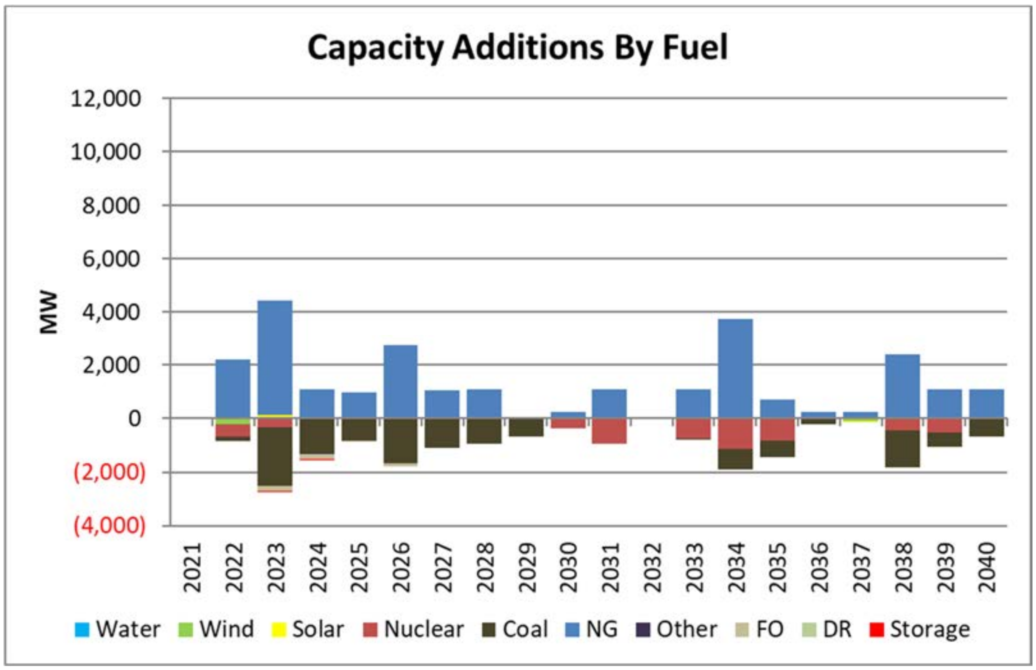


13.6 MARKET EXPANSION

Absent any market rule on CO2 emissions and with relatively abundant and cheap fuel sources, the transition to natural gas in the High Growth Case becomes very slow.

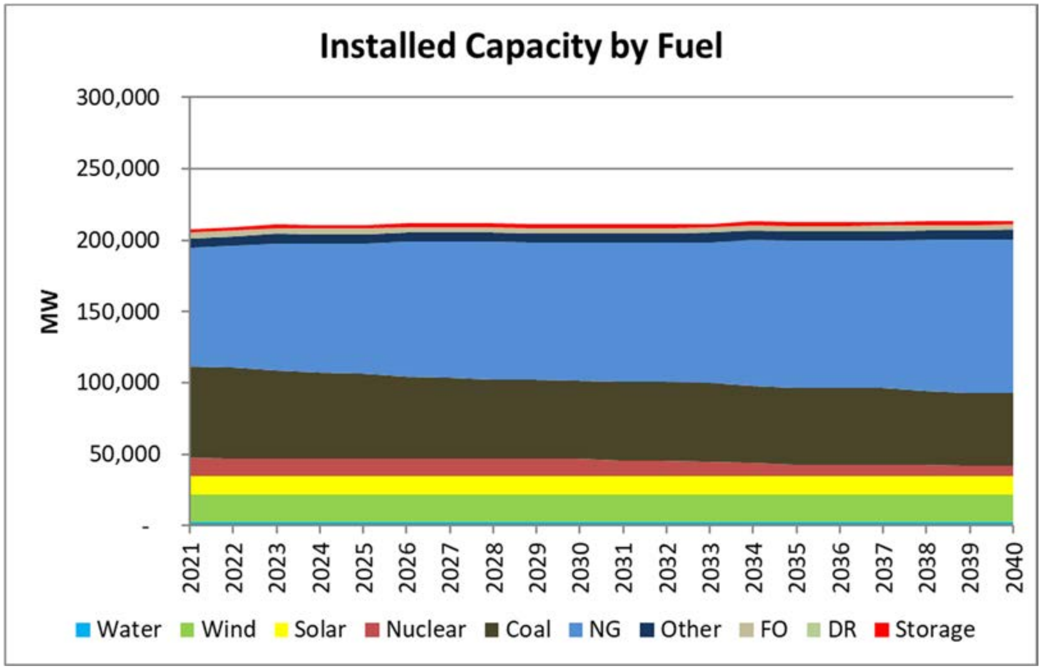
The chart below illustrates the year-over-year changes in capacity additions and retirements in the MISO market under the High Growth Case assumptions. Coal retirements are replaced with natural gas fired generation given its low capital cost. Most renewable expansion occurred in 2021 as reflected in Figure 85.

Figure 84 High Growth Case - MISO Net Capacity Additions by Fuel



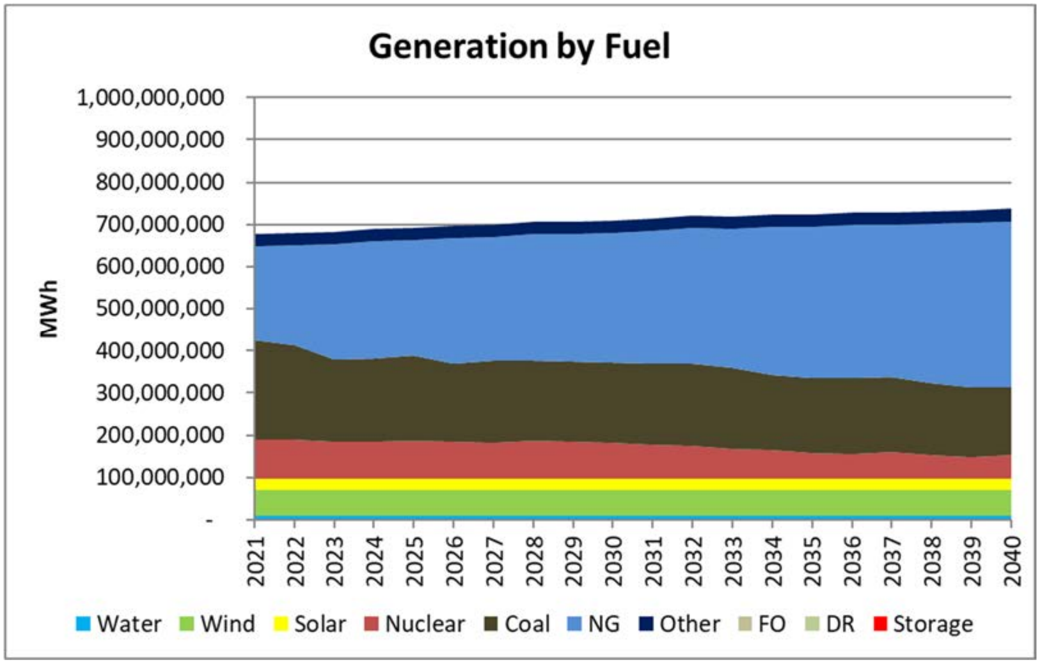
Consistent with the outlook presented above, installed capacity gradually shifts from coal to natural gas with little in the way of other additions after 2021.

Figure 85 High Growth Case - MISO Net Capacity Additions by Fuel



Over time, coal generation becomes less and less a role in the MISO market, despite there being no tax or penalty assumed on coal (or carbon) in the High Growth Case. This is ultimately driven by comparatively cheap natural gas and low capital costs for natural gas assets.

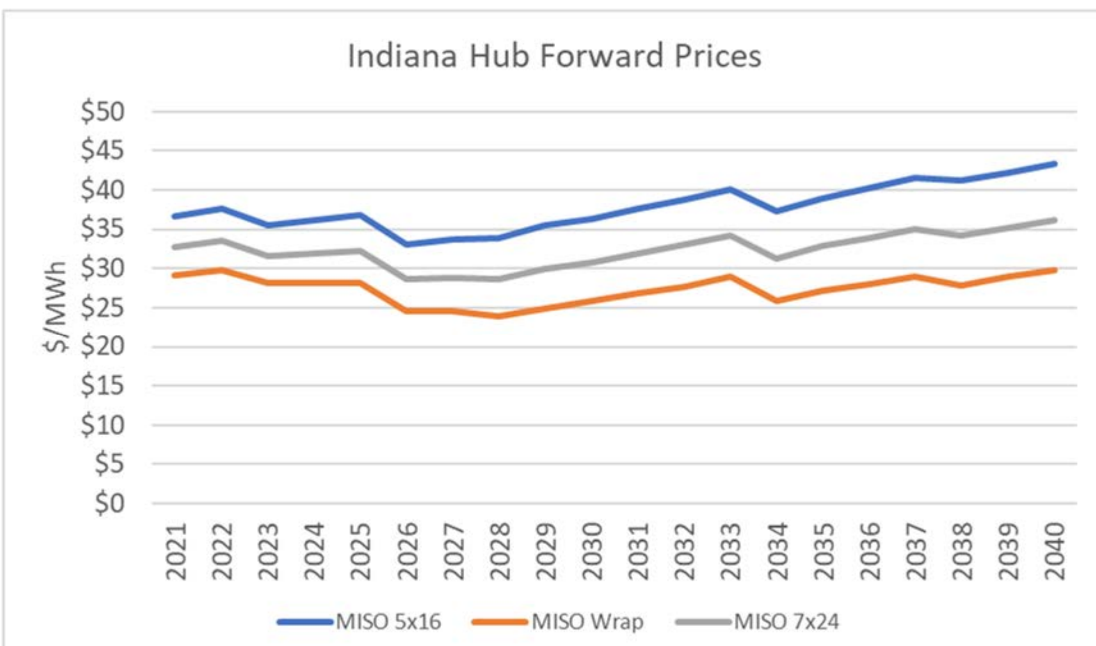
Figure 86 High Growth Case - MISO Generation by Fuel



MISO Market Prices

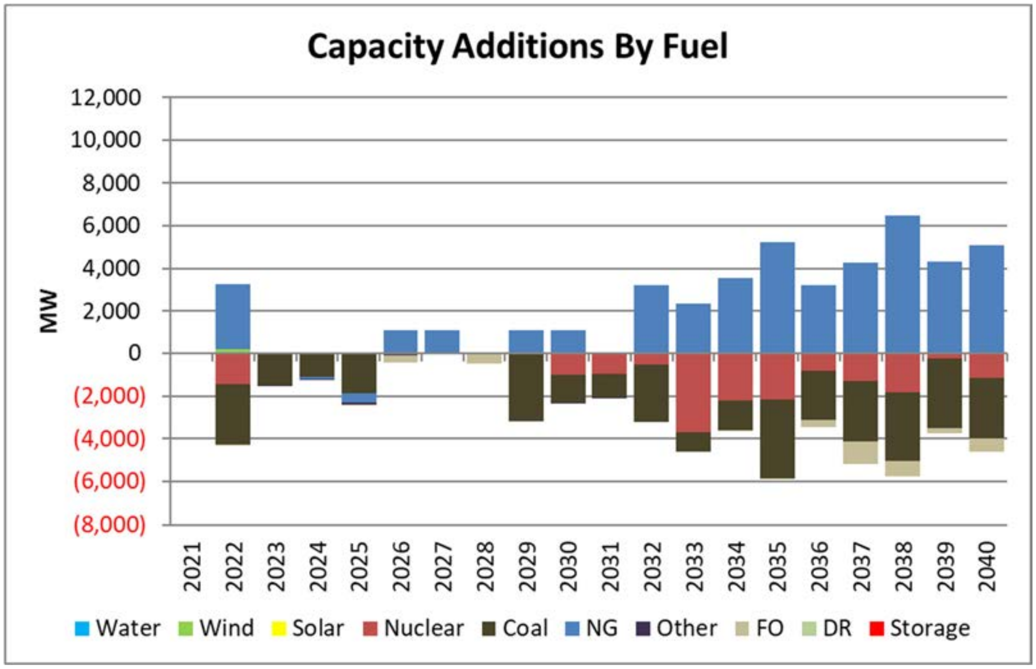
The resulting market prices from the MISO expansion are shown below.

Figure 87 High Growth Case – Indiana Hub Prices



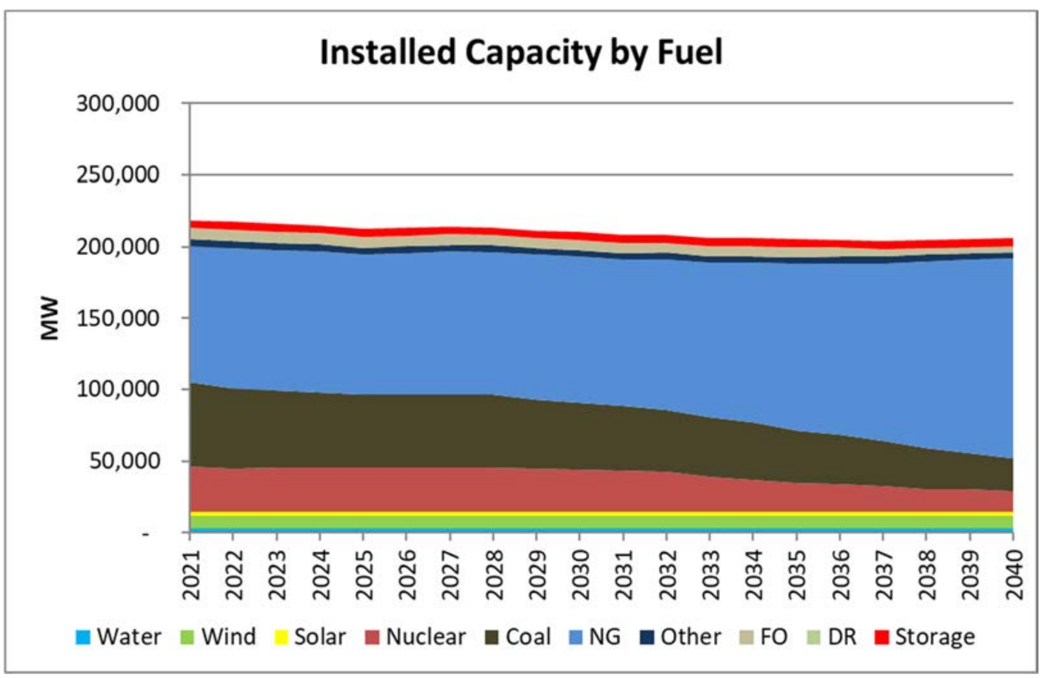
As has been previously shown, the PJM market's reserve margin is high in the near term. As a result, there is very little need for new capacity until 2032. These retirements are replaced entirely by natural gas generation.

Figure 88 High Growth Case – PJM Net Capacity Additions by Fuel



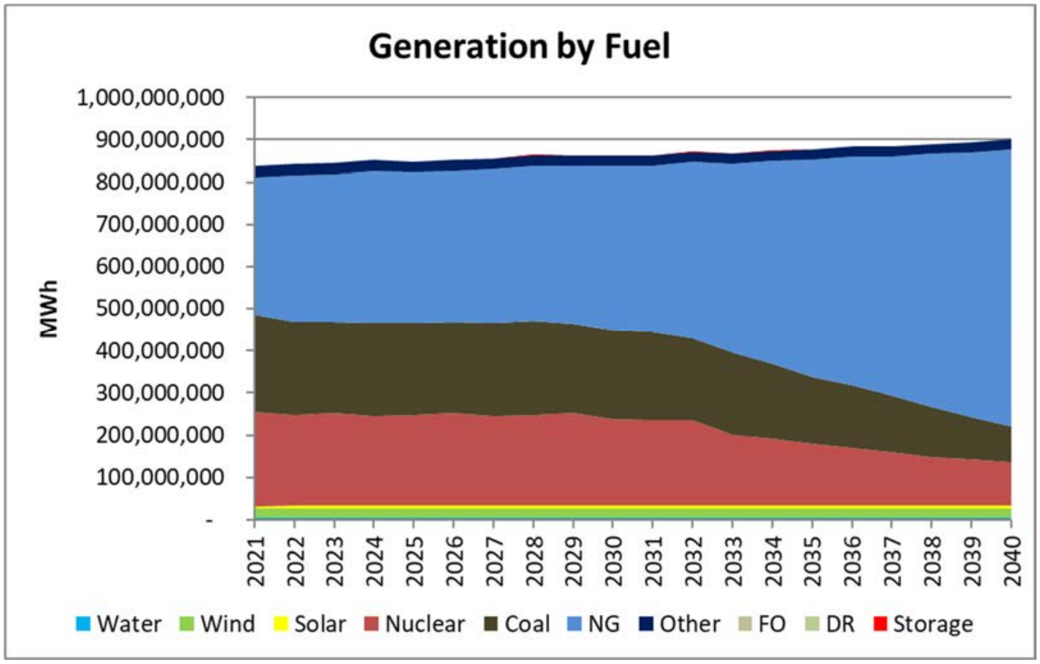
As is the case in MISO, installed capacity shifts increasingly, yet slightly, to being dominated by natural gas.

Figure 89 High Growth Case – PJM Installed Capacity by Fuel



As is consistent with the previous charts, coal generation gradually loses competitiveness to new gas fired generation in PJM.

Figure 90 High Growth Case – PJM Generation by Fuel

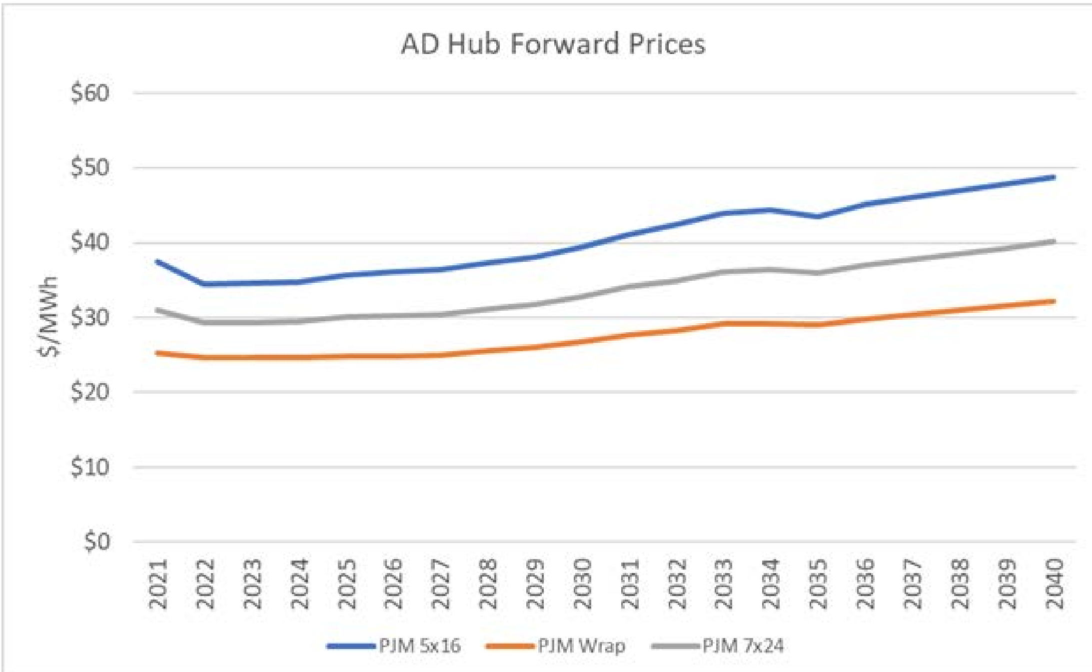


In the modeling of all cases, it is notable that coal loses market share in all 3 scenarios. In the base case, the presumed CO2 tax, although modest, accelerates the inevitable decline in coal generation. As illustrated in the High Growth Case, coal fired generation's high cost is too much to overcome when faced with lower technology costs and competitive fuel supply. Coal, simply stated, is not the path forward in any of the three scenarios modeled.

PJM Market Prices

PJM prices from the resulting expansion are shown below.

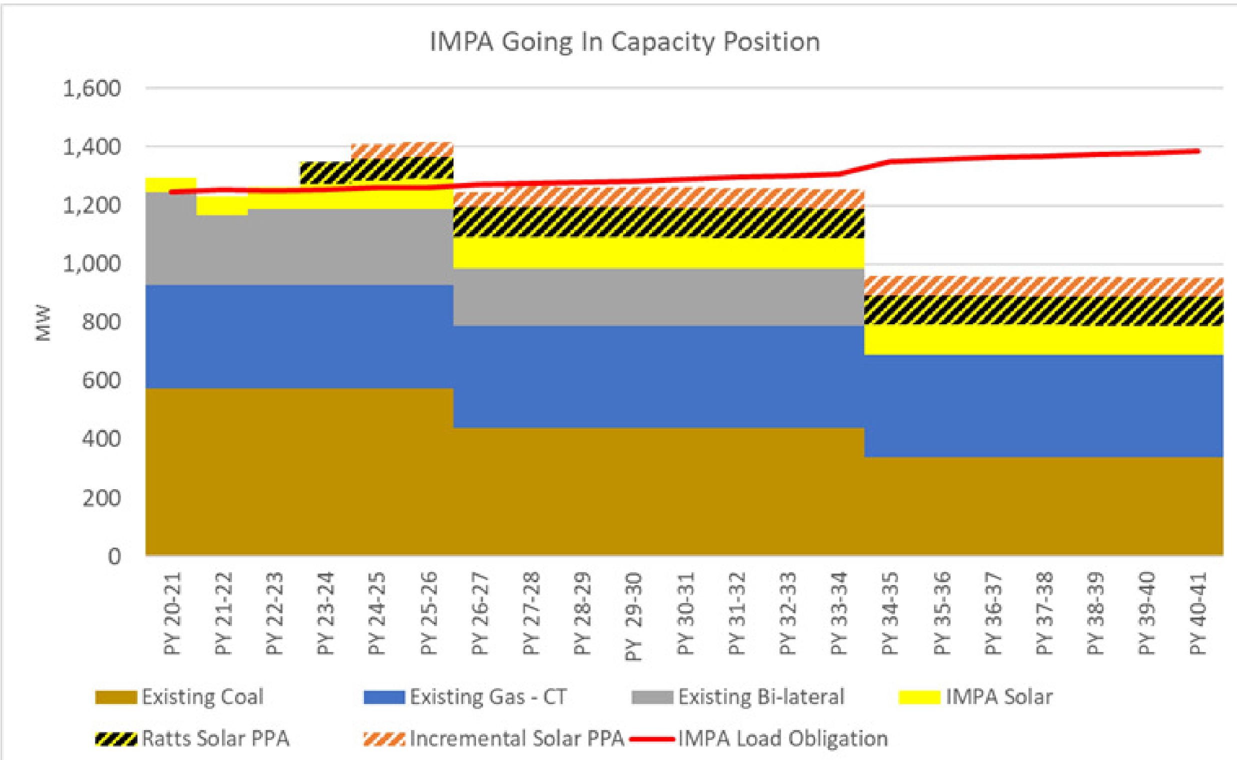
Figure 91 High Growth Case – AD Hub Prices



13.7 Portfolio Selection

Identical to the Base Case process, the IMPA portfolio is optimized for cost within the market expansion that was created. In this case, the portfolio is deterministically optimized around a world where there is comparatively cheap natural gas, high economic growth, and subsequently higher loads. The chart below illustrates the going in position for the optimization. It echoes the base and green case going in positions but with higher load obligations.

Figure 92 High Growth Case – Going In Capacity Position



The model acquires additional solar prior to the PY 26-27 retirement of Gibson 5, but the bulk of that need is replaced with a 125 MW off take from a combined cycle. The AEP contract is replaced with roughly 180 MW of combined cycle and 100 MW of solar. Note that due to scaling, the load requirement illustrated appears close to the base case but does reflect the higher obligation assumed under the High Growth Case.

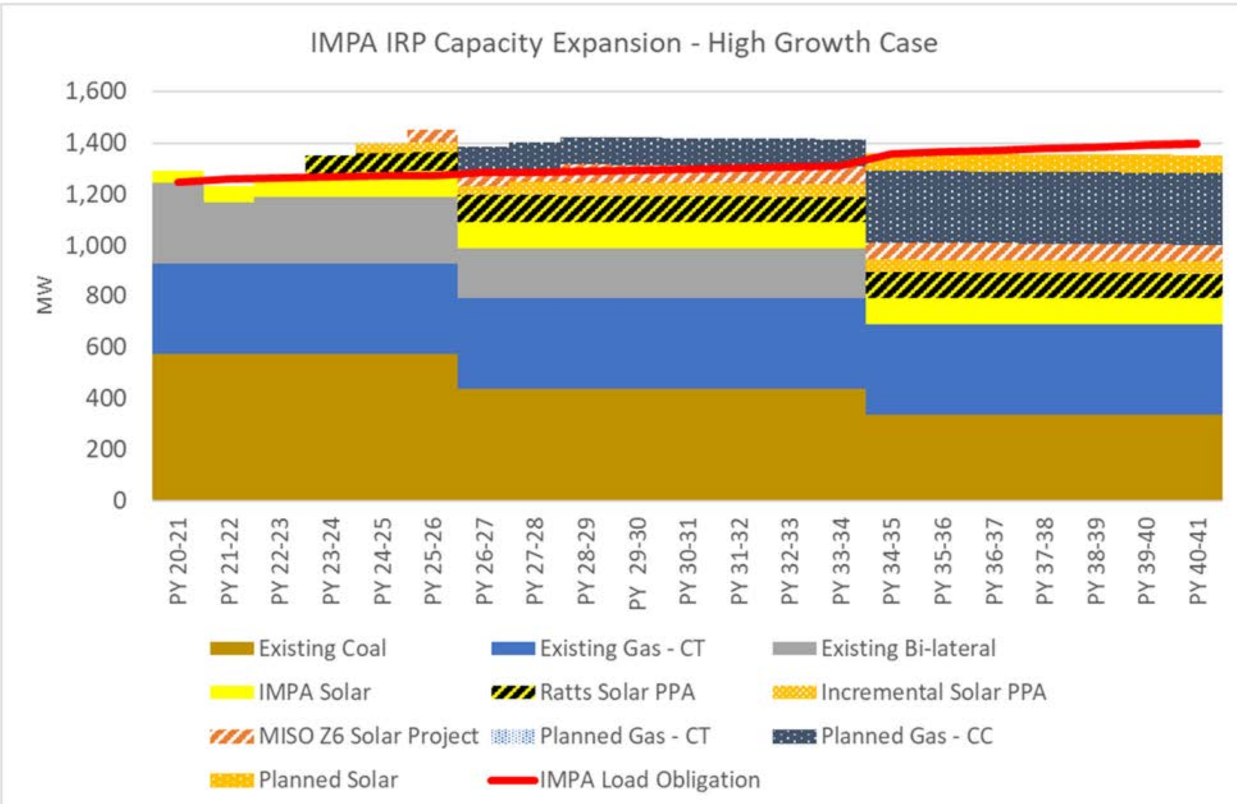
The table below illustrates a year by year summary of capacity additions and withdrawals under the high growth case.

Table 17 High Growth Case Expansion Plan

IMPA High Growth Plan - ICAP Capacity (Summer Ratings)					
Planning Year	MW Withdrawn	MW Withdrawn Notes	MW Capacity Added	MW Capacity Added Notes	Net Capacity Added/(Withdrawn)
PY 21-22	-100	Duke Option Expires	72	Increase in Bilateral Contract Qty, IMPA Solar	-28
PY 22-23			111	Increase in Bilateral Contract Qty + IMPA Solar + Alta Farms Wind PPA (Energy Only)	111
PY 23-24			161	Ratts Solar PPA + IMPA Solar	161
PY 24-25			111	Solar PPA (currently in negotiation) + IMPA Solar	111
PY 25-26			111	MISO Z6 Solar Project + IMPA Solar	111
PY 26-27	-231	Gibson #5 Retirement/Bilateral Capacity Expiration	136	Planned Natural Gas Combined Cycle (125 MW) + IMPA Solar	-95
PY 27-28					
PY 28-29					
PY 29-30					
PY 30-31					
PY 31-32					
PY 32-33					
PY 33-34					
PY 34-35	-286	AEP Contract Expiration/WWVS Retirement	283	Planned NG Combined Cycle + 100 MW Solar	-3
PY 35-36					
PY 36-37					
PY 37-38					
PY 38-39					
PY 39-40					
PY 40-41					

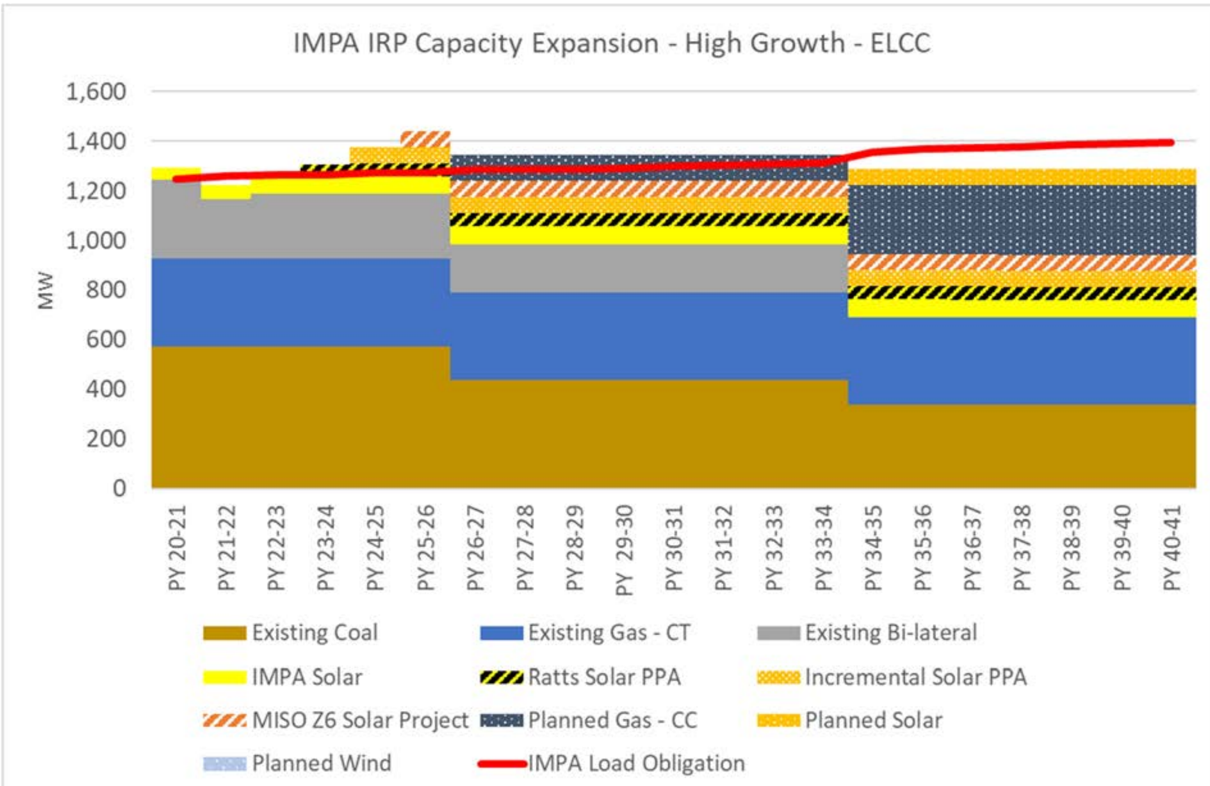
The figure below shows the capacity position after the High Growth optimization but before ELCC accreditation.

Figure 93 High Growth Case – Expansion Plan



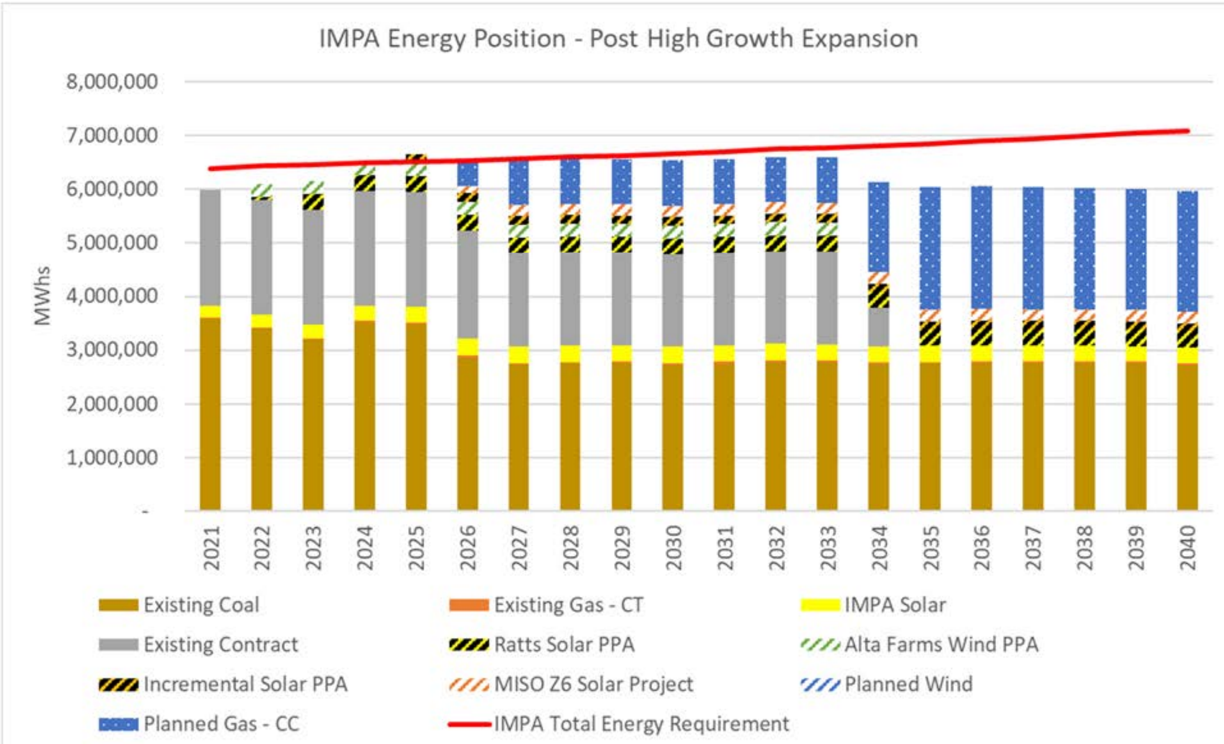
The following figure illustrates the application of the ELCC to the High Growth Case build plan. The ELCC figures used in this case result in a higher capacity credit due to the lower installed zonal capacity of renewable resources. When the forecast ELCC value is applied based on the modeled installed capacity of solar, much of the capacity length seen previously is mitigated. In addition, there is still a capacity shortfall of a little over 50 MW in PY 34-35.

Figure 94 High Growth Case – Expansion Plan with Adjusted ELCC



IMPA's energy position after optimization is relatively balanced with only a slight short energy position expected after 2034.

Figure 95 High Growth Case – Post Expansion Energy Position

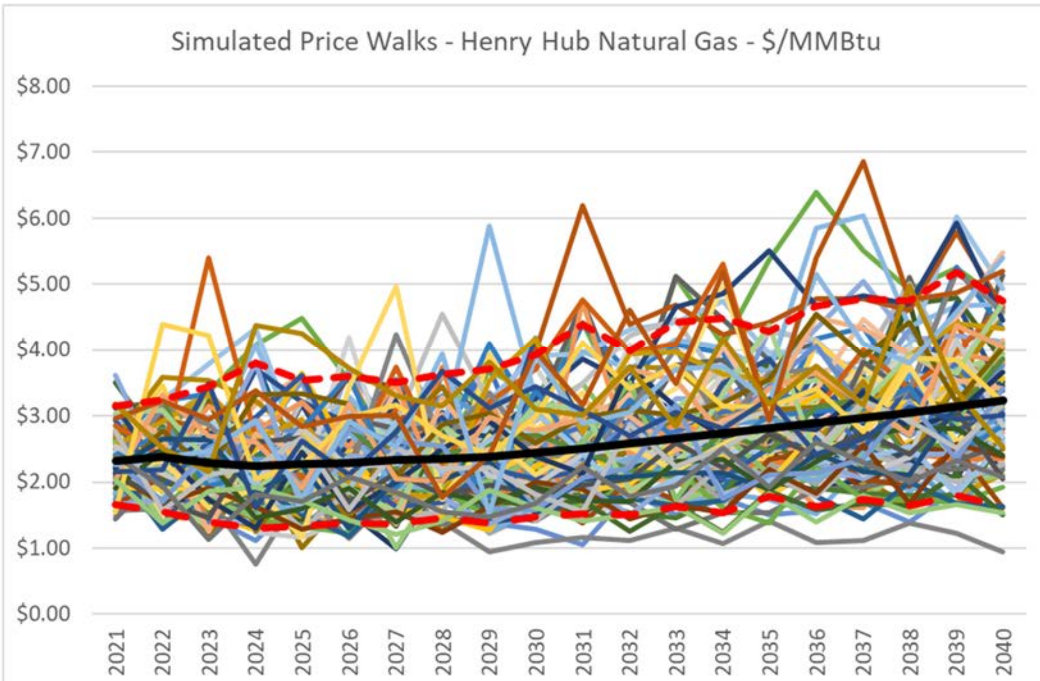


13.8 STOCHASTICS

The following figures reflect the stochastic elements of the High Growth Case run.

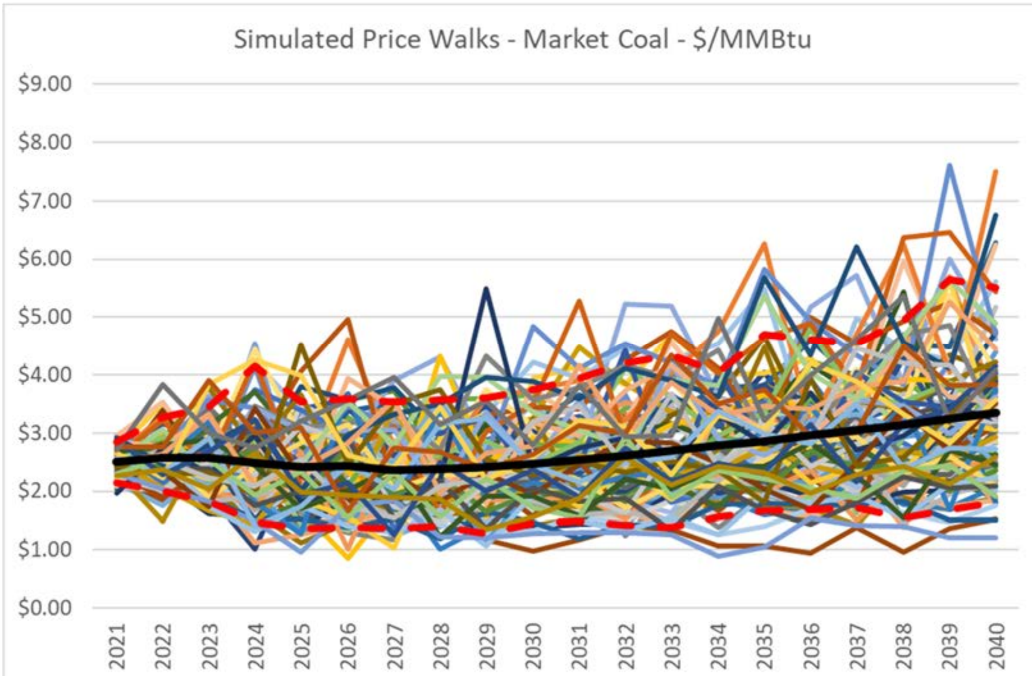
Natural gas volatility is presumed to be the same, however, with a lower overall expected mean (as reflected in the underlying High Growth Case assumptions. Consequently, the tail risk in natural gas is nominally lower in some draws than seen in the Green and Base Cases.

Figure 96 High Growth Case - Henry Hub Gas Simulated Price Walks



Coal prices and their volatility are shown in the figure below. The mean price for coal reflects the expected mean for coal in the High Growth Case. This happens to be very close to the Henry Hub assumption and formatting may make differences difficult to distinguish between the Henry Hub charts.

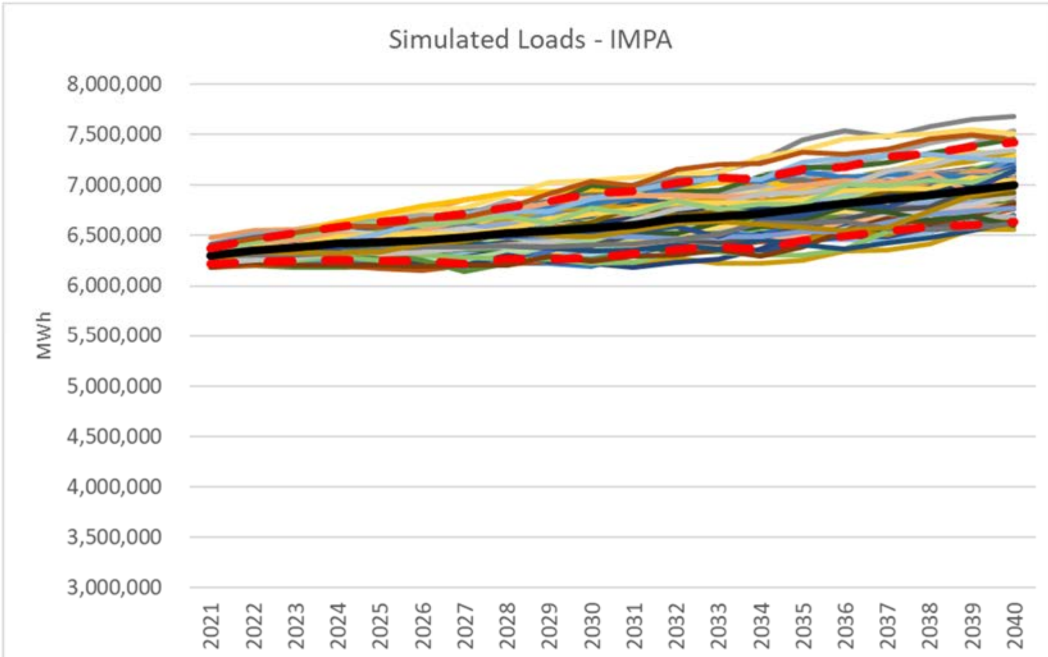
Figure 97 High Growth Case - Market Coal Simulated Price Walks



In the high growth case, there are no CO2 price assumptions. Consequently, there were no simulated price walks for CO2.

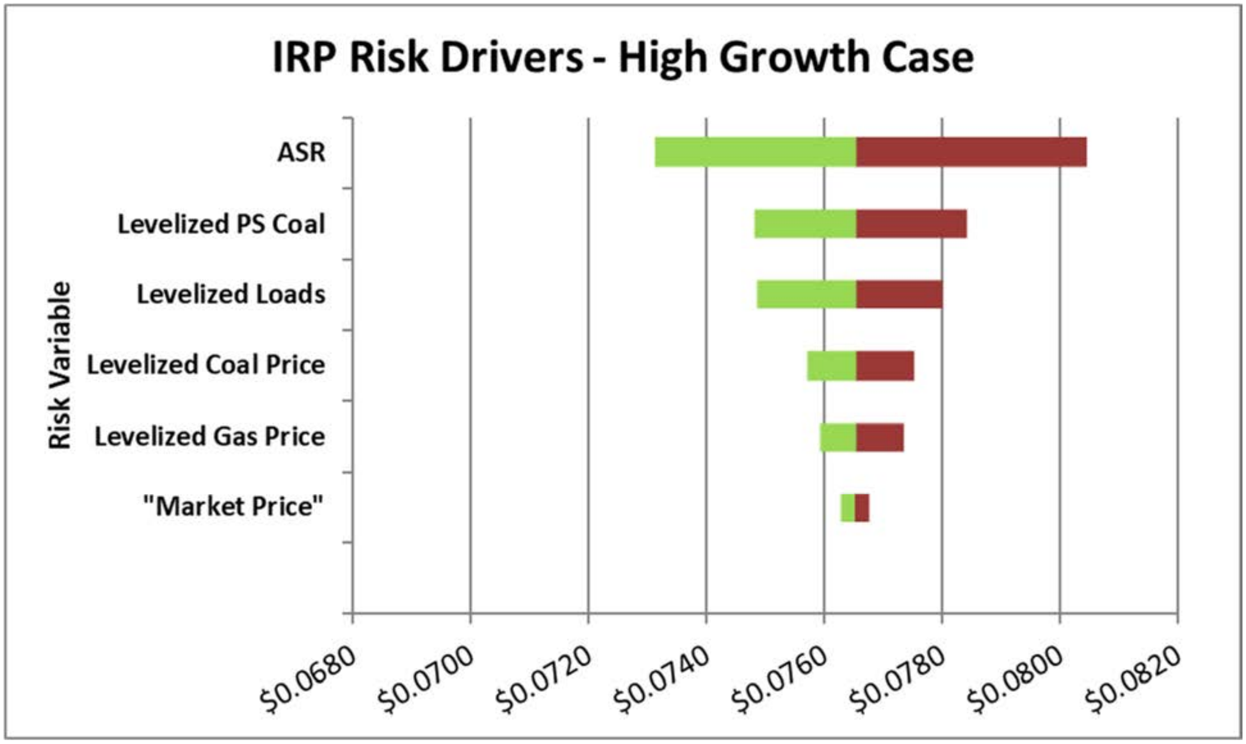
Loads were the final parameter to model stochastically. The stochastic portfolio loads are shown in the figure below. System loads were also modeled stochastically.

Figure 98 High Growth Case - Simulated Load Walks



13.9 PORTFOLIO ASSESSMENT

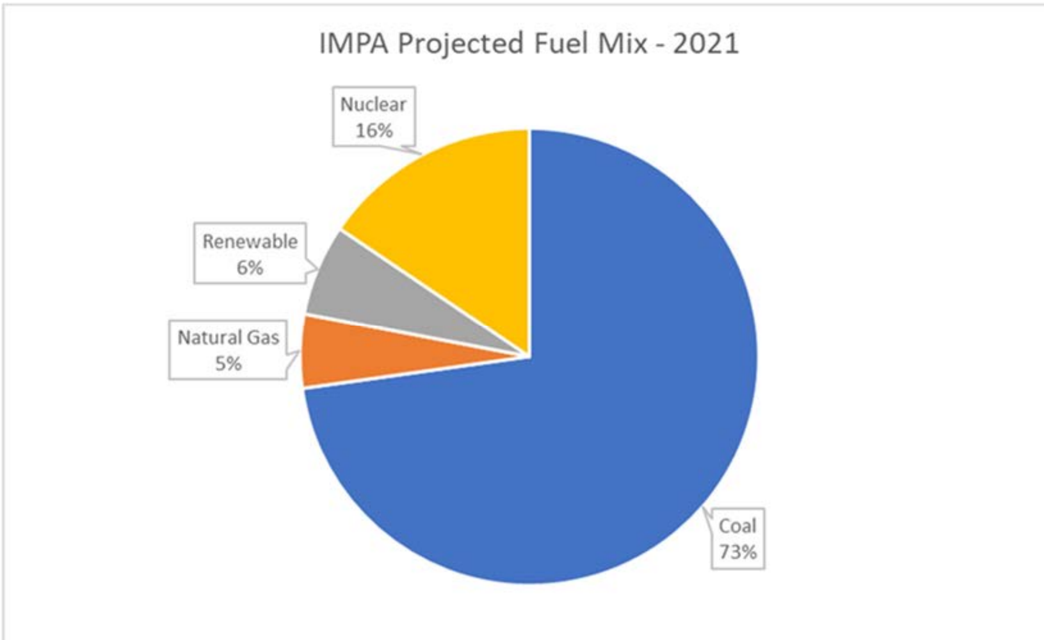
Figure 99 High Growth Case – Tornado Chart



The Average System Rate (ASR) has an expected mean of $.076/kWh (versus the Base Case ASR of $.0830). Key risks are coal prices at Prairie State and loads. Despite the addition of combined cycle capacity, uncertainty in natural gas prices is not significant relative to other factors. In addition, the price at which IMPA is expected to interact with the market is minimal.

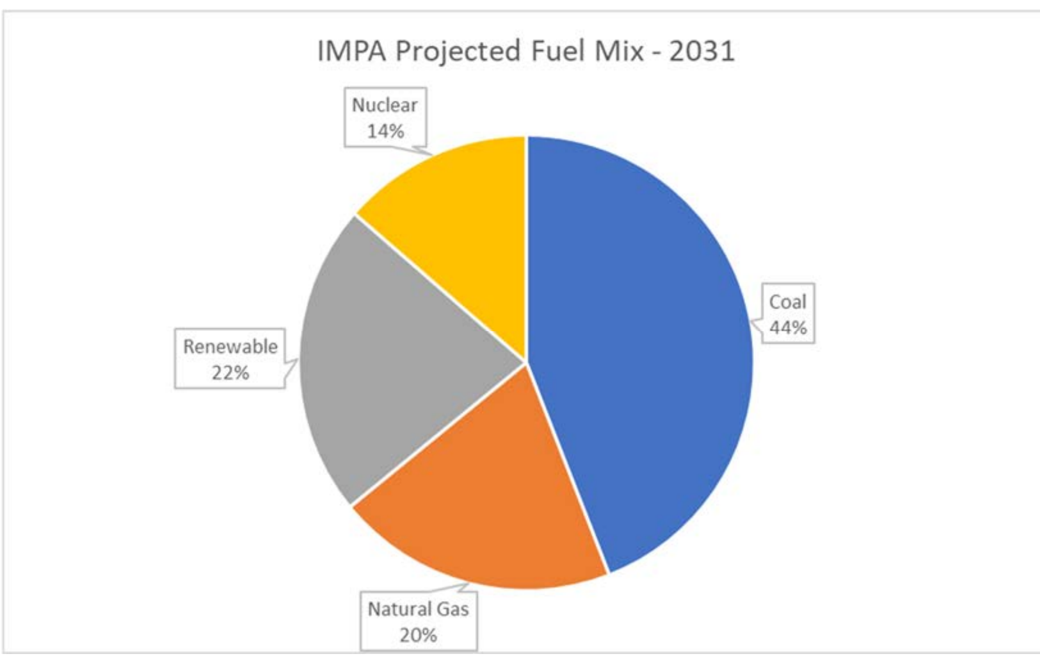
As noted in the market expansion discussion of the High Growth Case, even absent any penalty on carbon, coal faces a bleak future as natural gas fueled generation out competes coal generation on both a capital cost and fuel cost basis.

Figure 100 High Growth Case - 2021 Fuel Mix



Even in a "High Growth" world, IMPA sees a transition away from coal generation that is similar to the Base Case, but more natural gas dependent.

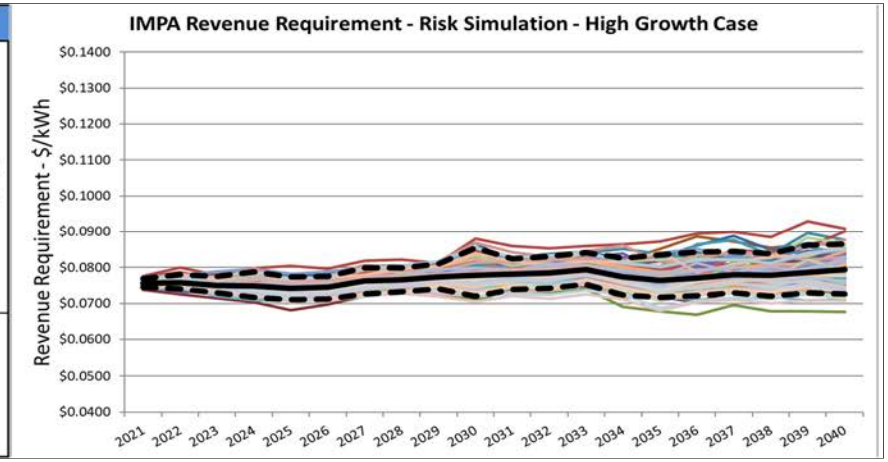
Figure 101 High Growth Case - 2031 Fuel Mix



13.10 HIGH GROWTH CASE SUMMARY

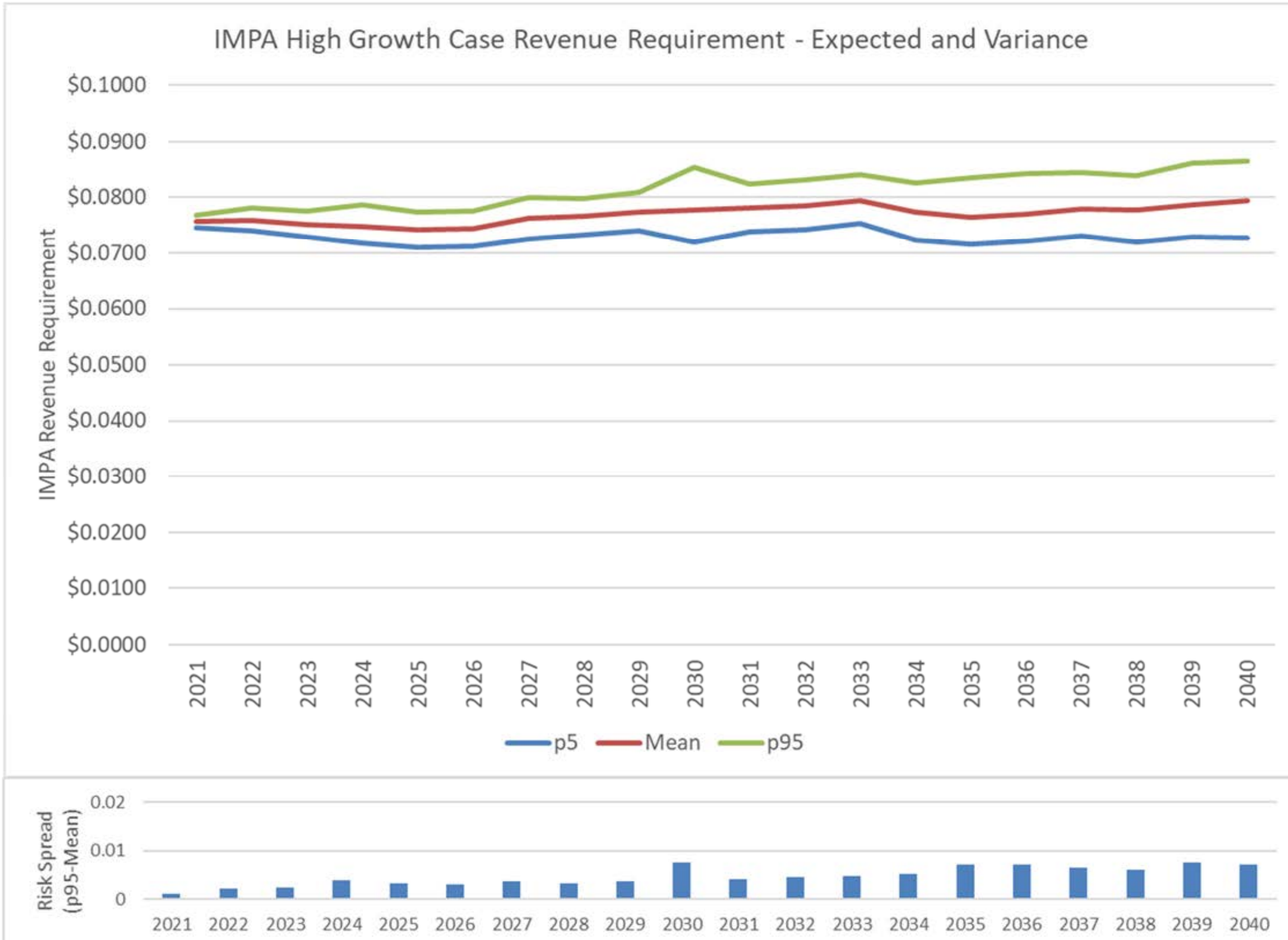
Plan Summary: In this optimization, generation retirements include Gibson 5 on 5/31/2026 (156 MW) and Whitewater Valley Station on 5/31/2034 (90 MW). Over the study period, IMPA sees the net expiration of 321 MW of bilateral/full requirements capacity contracts. Planned replacements include 100 MW of solar pre-ITC expiration and 125 MW of natural gas combined cycle. In PJM, planned replacements include 183 MW of natural gas combined cycle along with 100 MW of solar.

Drivers	Robust Growth/De-regulation
Economic Growth	2.0%
Capital Costs	Reference
Load Forecast	IMPA Reference +1%
Natural Gas Prices	Reference x EIA High Growth Case
Coal Price	Base Case x EIA High Growth Case
CO2 Policy	None
RPS	No
Reserve Margin	Reference Area
Asset Retirements - ICAP MW	-246
Net Market Capacity Transactions - ICAP MW	-321
Natural Gas Additions - ICAP MW	308
Renewable Additions - ICAP MW	627

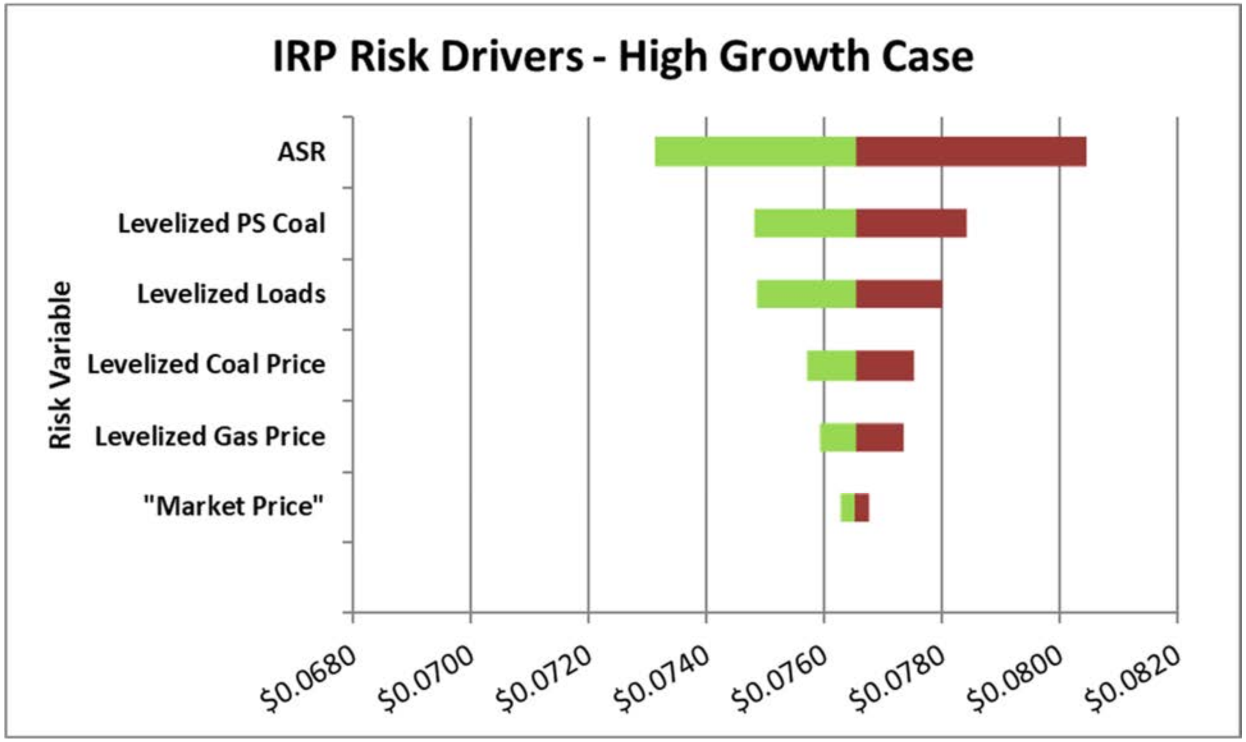


Plan Observations: Despite not having any penalty for CO2 emissions, the High Growth Plan sees IMPA transition away from coal fired generation, replacing coal retirements with a combination of solar and natural gas combined cycle resources. Nevertheless, coal remains a relatively large source of fuel risk in the High Growth Case portfolio, however, overall risk in the plan is the lowest among the three scenarios.

Risk Profile Observations: Overall the risk profile of the High Growth Case portfolio is among the lowest of the three cases, largely due to the assumption of no regime change during the study horizon (i.e., carbon).



Tornado Chart Observations: Absent any carbon pricing regime, IMPA's risks are largely related to fuel (Prairie State Coal) and member loads. With a relatively high fixed cost base, deviations in loads can have large impacts on expected revenue requirement. Less material risks stem from natural gas prices and the cost of market purchases.



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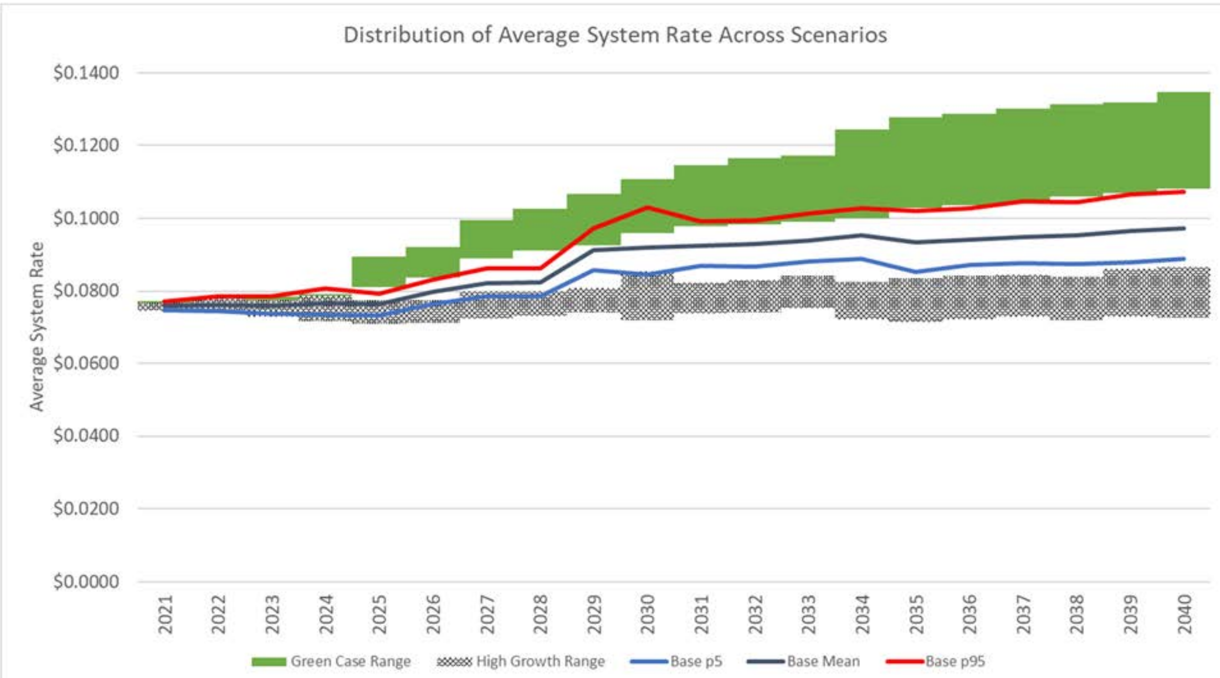
14 PLAN COMPARISON AND SELECTION

14.1 PLAN COMPARISON - RESULTS

Average System Rate Comparison: The aggressive assumptions made in the Green Case give it the widest range between the P5 and P95, largely driven by the assumption of a dramatic pivot away from carbon intensive resources and an aggressive CO_2 tax. At best, the P5 of the Green Case would still be more expensive in some years than the p95 of the Base Case. Conversely the worst case of the High Growth Case would still have less rate impact than the p5 scenario in the Base Case.

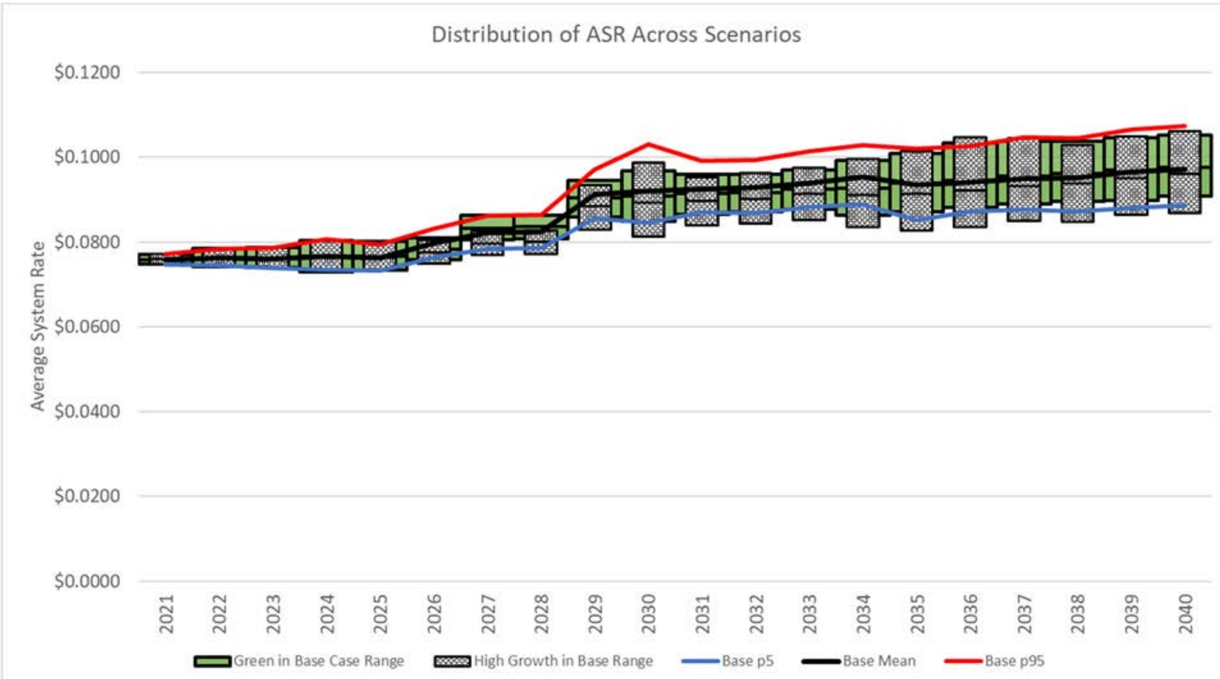
Figure 102 Plan Comparison - Stochastic Results



In the numbers reflected above, each portfolio has been optimized for its future expected environment. Unsurprisingly, the lowest cost portfolio is the portfolio designed for a world where fuels are abundant and cheap, and CO_2 emissions are not subject to any legislation or tax. Conversely, the most expensive portfolio is the portfolio that is optimized for a world where CO_2 emissions are taxed heavily. As a measure of robustness, IMPA opted to run final stochastic runs where the Green Case and High Growth Portfolios were implemented in the Base Case world.

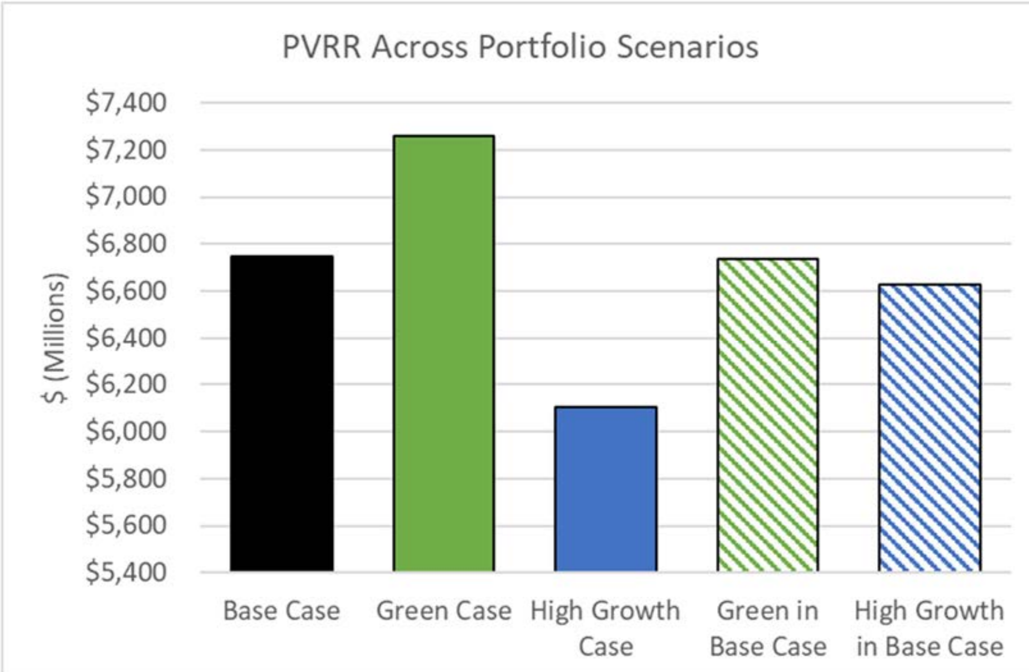
Portfolio Cross Analysis: IMPA has modeled three different future paths and created an optimized portfolio for each path. As an additional test of robustness, IMPA has modeled the green and high growth portfolios under the base case assumptions. The chart below illustrates the range of projected ASR at for the base case, as well as the range of outcomes for the Green Portfolio in the Base Case and the High Growth Portfolio in the Base Case.

Figure 103 Plan Comparison - Comparison of Stochastic Results – Cross Analysis



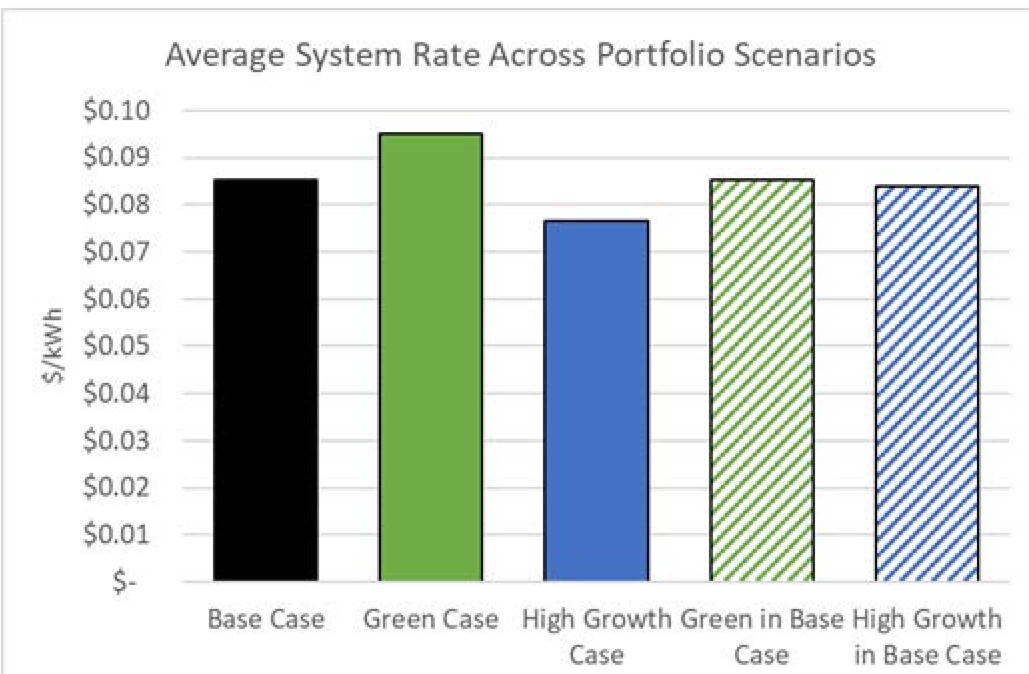
The figure below shows the Present Value of Revenue requirements.

Figure 104 Plan Comparison – Present Value of Revenue Requirements



On an average system rate basis, the portfolios are much closer yet rank roughly the same.

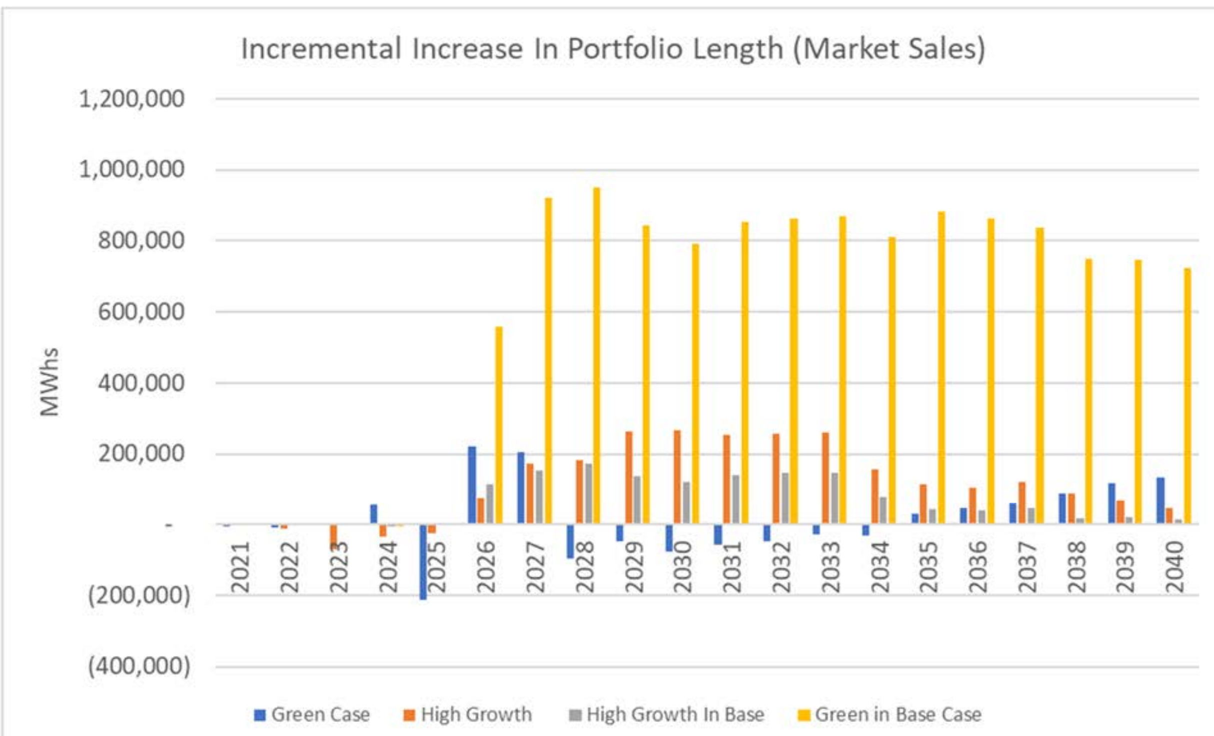
Figure 105 Plan Comparison – Average System Rate (ASR)



Upon initial inspection, it would appear that pursuing either the Green Portfolio or the High Growth Portfolio would provide advantages over the Base Case portfolio. Both portfolios have similar expected revenue requirements and arguably better risk profiles, with both the green/high growth ranges generally coming in under the P95 range of the base portfolio. However, this ignores the fact that both the Green and High Growth Case have combined cycle positions in them. These assets ultimately replace a significant amount of the lost energy from the Gibson retirement, whereas the Base Case uses a CT to replace the lost capacity. The result is both the Green and High Growth portfolios, when placed in the Base Case world, effectively shift some of IMPA's existing resources up the resource stack and ultimately increase market sales relative to the base case. Conversely, the Base Case, by utilizing a CT to replace the capacity, leaves more of the open energy position to market purchases. As these purchases are not yet fixed in price, this creates more volatility in the Base Case portfolio. In practice, IMPA would hedge much of this open position with either forward contracts or renewable energy projects as market conditions warrant. More critically, by keeping these positions open, as reflected in the Base Case, IMPA retains a real option to defer investment in generation assets (for energy) in favor of purchase power contracts until market landscapes become clearer.

As illustrated in figure below, the increase in length from adding a combined cycle is some cases is egregious (e.g., Green in Base Case).

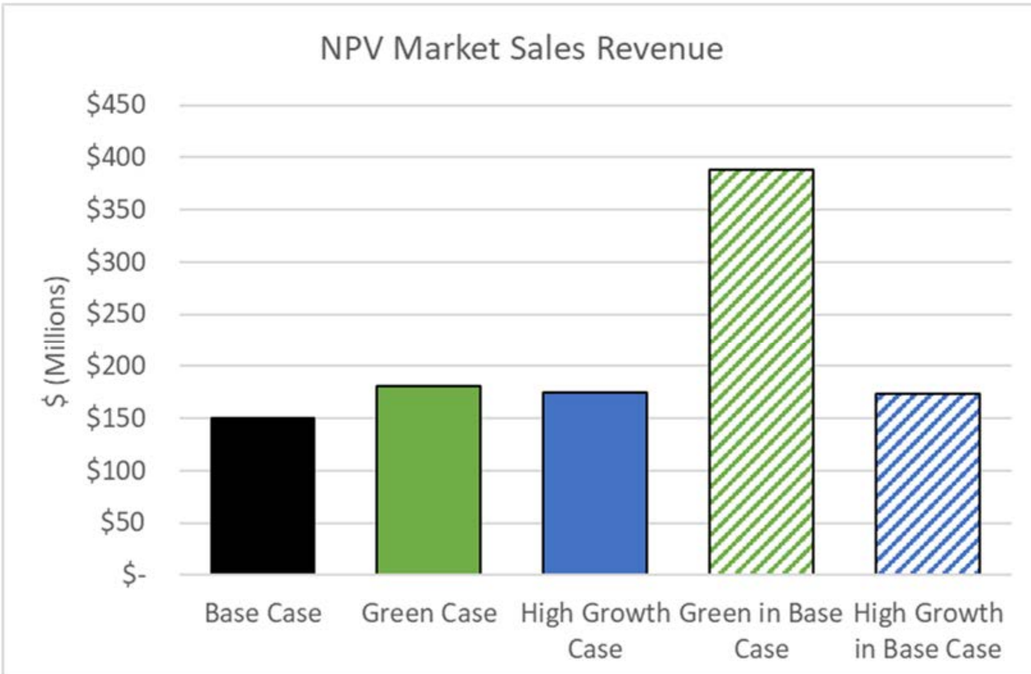
Figure 106 Plan Comparison - Portfolio Length



Clearly, the Green Portfolio in Base Case world benefits from a massive increase in market sales. Implementing this portfolio while expecting a base case set of outcomes to materialize is overly reliant on future market revenue from the excessive portfolio length. As a result, it is both impractical and imprudent to implement.

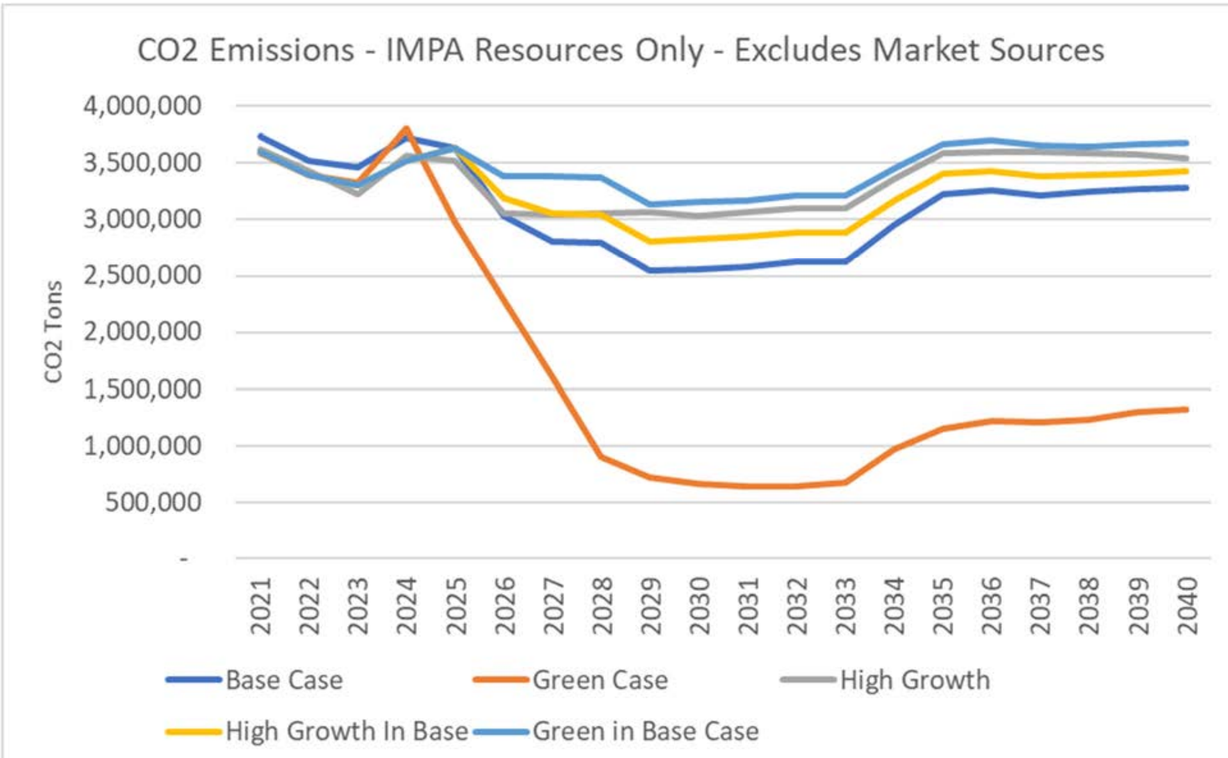
The High Growth Case in the Base Case world does not suffer from this problem and actually has lower market sales than the High Growth portfolio due to the natural gas price differential between cases. However, moving forward with the High Growth Portfolio, despite the minor impact in portfolio length, seems suboptimal from an emissions standpoint.

Figure 107 Plan Comparison – NPV of Market Sales Revenue



CO_2 Emissions: The chart below illustrates CO_2 emissions from IMPA owned resources and excludes exposure from market purchases and contracts. Clearly, the Green Case Portfolio has the lowest CO_2 emissions stemming from non-existent coal generation as a consequence of a very high CO_2 tax.

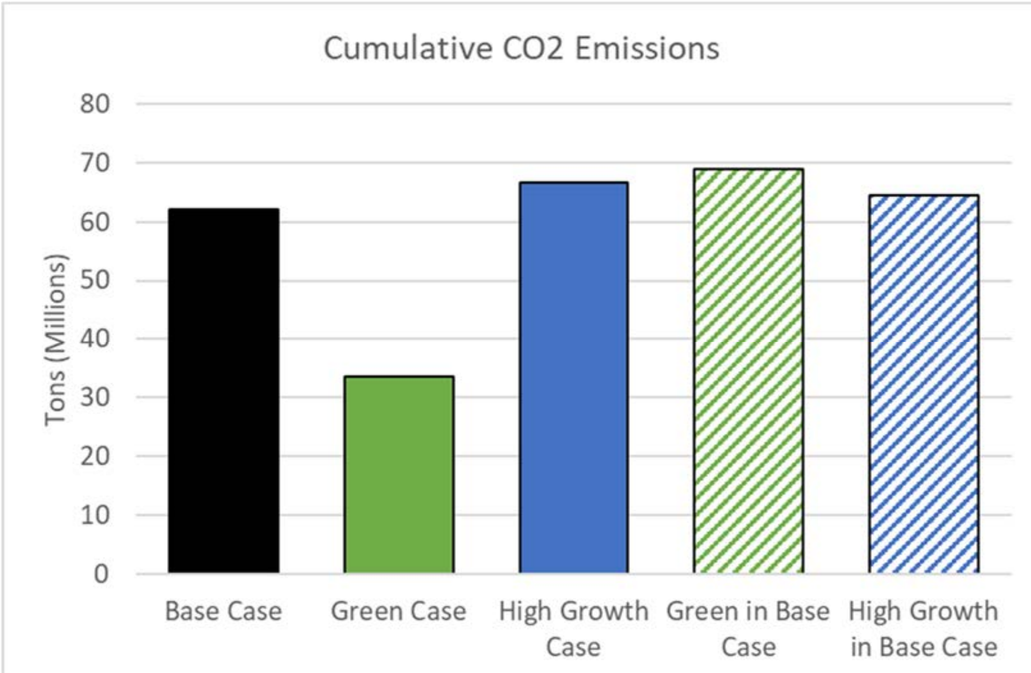
Figure 108 Plan Comparison – CO_2 Emissions



However, the next best portfolio from an emissions standpoint is the Base Case, as optimized for expected future conditions. The increase in 2034 is from the loss of the AEP contract, counted here as having no CO_2 exposure, with combined cycle generation as replacement capacity and energy.

The table below shows cumulative CO_2 emissions in each plan.

Figure 109 Plan Comparison – Cumulative CO2 Emissions



The table below summarizes the metrics illustrated in the previous charts.

Table 18 Plan Comparison – Portfolio Metrics

Portfolio Metric/Case	*Base Case*	*Green Case*	*High Growth Case*	*Green in Base Case*	*High Growth in Base Case*
PVRR (millions)	\$6,748	\$7,259	\$6,102	\$6,735	\$6,629
ASR \$/kWh	\$0.085	\$0.095	\$0.077	\$0.085	\$0.084
NPV Market Sales Revenue (millions)	\$150	\$181	\$175	\$388	\$174
CO2 Tons (millons)	62	34	67	69	65

Pursuing the High Growth portfolio would mean that IMPA would need to be confident in no CO2 legislation occurring over the IRP horizon. In addition, IMPA believes it has some social responsibility to curb greenhouse gas emissions where economical.

14.2 Plan Comparison - Discussion

IMPA's Renewable Energy Plan. IMPA believes that in one way or another CO2 legislation will come someday. In addition, utility ratepayers of all classes are increasingly interested in renewable energy and what their utility is doing about it. As such, with the approval of IMPA's Board of Commissioners, IMPA has been moving ahead with renewable energy acquisitions over the last several years. In the last IRP, IMPA's action plan stated that it would seek to replace the expiring Crystal Lake wind contract with additional renewable sources as well as continue its internal solar park program.

In 2018, IMPA issued a renewable RFP resulting in the signing of the Alta Farms II wind contract. As solar prices continued to fall into 2019, IMPA issued another RFP for wind and solar resources that resulted in the signing of the initial Ratts I solar contract. IMPA issued a third renewable RFP in early 2020. This RFP resulted in the expansion of the Ratts contract to 150 MW and the 100 MW offtake currently being negotiated. These contracts have allowed IMPA to procure carbon free energy for up to 20 years at fixed prices at or below the forward curve.

Meanwhile, IMPA's behind the meter solar generation builds have continued. Using tax equity partners, IMPA is building these parks at very competitive prices compared to industrial scale solar parks. The goal is to have approximately 200 MW of these small parks built throughout IMPA member territories.

IMPA's Power Supply Portfolio. Even with the retirement of Gibson 5, IMPA will still have 368 MW of baseload coal and 197 MW of base load purchased power. These 565 MW of resources cover a substantial portion of IMPA's energy needs. The renewable programs and contracts discussed in this report add another large block of energy, mostly in the on peak periods. Today's CCs are so efficient and gas is so low priced, they effectively have become base load sources. By the time the renewable PPA contracts start, IMPA's portfolio will be situated in such a way that additional baseload energy is not required and the CC simply leads to even more off system energy sales. Furthermore, installation of a CT covers IMPA capacity position while still giving the agency flexibility to meet changing load, regulatory and environmental conditions.

IMPA expects power supply portfolios to become increasingly driven by renewable sources. Given IMPA's expansion into solar, solar will ultimately displace baseload generation in those hours solar is producing, shifting IMPA's baseload "up the stack." This effectively makes those baseload resources "intermediate." Traditionally, natural gas combined cycles have occupied the "intermediate" slot in power supply portfolios. Were IMPA to add a combined cycle, it effectively creates excess portfolio length in baseload/intermediate resources. In addition, IMPA firmly believes that increased renewable penetration in wholesale markets will shift value drivers from what has been historically energy and capacity related value streams to becoming more focused on rewarding flexibility and resilience to the grid. CTs, with quick start, quick ramping capability, will be able to provide this capability to wholesale markets and add downstream value to IMPA members. Finally, capacity positions are difficult to hedge in bilateral markets, while energy positions are much easier to hedge. Bilateral capacity markets are generally illiquid and as a result, not very competitive. By comparison, energy markets frequently are two sided (i.e., multiple parties quoting a price at which they will buy or sell) and much more competitive. By filling IMPA's capacity need with a CT, IMPA hedges the illiquid, hard to hedge risk with a technology that is very low cost and NOT subject to rulemaking risk on its ability to provide capacity and reliability services when called on to do so. For energy requirements, IMPA can then utilize the very liquid forward markets for power or continue to diversify its power supply portfolio with renewables as market conditions dictate.

Self-build CT vs Joint-owned CC. While two of the three portfolios have combined cycles as an optimal solution, given the relative complexity and size of current combined cycle facilities, IMPA would need to partner with several entities on a project. Currently, there are no active MISO interconnection requests for a combined cycle located in MISO Zone 6.[14] Given the capacity need and the relatively long "runway" needed for combined cycle development, it is more expeditious for IMPA to pursue CT development. This is an arena where IMPA has direct experience and, in pursuing this approach, IMPA achieves a level of self-determination for its capacity needs going forward. There may be opportunities for IMPA to work with other entities to build a multi-unit facility where each entity owns one or more specific units, such as the Georgetown CT arrangement.

[14] https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/gi-interactive-queue/

14.3 Plan Selection

Based on the foregoing analysis and report, IMPA is recommending the Base plan for the replacement of Gibson 5. This plan utilizes an advanced combustion turbine and various renewable energy resources to cover IMPA's capacity and energy needs when Gibson 5 is retired. This plan provides IMPA the flexibility to deal with changes in the economy, environmental rules as well as the regulatory and political landscape.

The table below illustrates the IMPA portfolio capacity prior to any capacity additions.

Table 19 IMPA Going In Capacity - ICAP* - ELCC

Resource/Year	*PY 21-22*	*PY 22-23*	*PY 23-24*	*PY 24-25*	*PY 25-26*	*PY 26-27*	*PY 27-28*	*PY 28-29*	*PY 29-30*	*PY 30-31*
Existing Gas - CT	373	373	373	373	373	373	373	373	373	373
Existing Coal	609	609	609	609	609	454	454	454	454	454
Existing Bi-lateral	246	271	271	271	271	196	196	196	196	196
IMPA Solar	53	51	46	37	36	34	34	34	34	34
Ratts Solar PPA	0	0	53	38	35	32	32	32	32	31
Incremental Solar PPA	0	0	0	25	23	21	21	21	21	21
MISO Z6 Solar Project	0	0	0	0	0	0	0	0	0	0
Planned Gas - CT	0	0	0	0	0	0	0	0	0	0
Planned Gas - CC	0	0	0	0	0	0	0	0	0	0
Planned Solar	0	0	0	0	0	0	0	0	0	0
Total Resources	1,281	1,304	1,351	1,352	1,346	1,110	1,110	1,110	1,109	1,108
Total Peak + Reserves	1,255	1,252	1,254	1,259	1,262	1,273	1,274	1,278	1,283	1,290

Resource/Year	*PY 31-32*	*PY 32-33*	*PY 33-34*	*PY 34-35*	*PY 35-36*	*PY 36-37*	*PY 37-38*	*PY 38-39*	*PY 39-40*	*PY 40-41*
Existing Gas - CT	373	373	373	373	373	373	373	373	373	373
Existing Coal	454	454	454	364	364	364	364	364	364	364
Existing Bi-lateral	196	196	196	0	0	0	0	0	0	1
IMPA Solar	34	33	33	33	33	33	33	31	31	31
Ratts Solar PPA	31	30	30	30	30	30	30	28	28	28
Incremental Solar PPA	21	21	21	21	21	21	21	20	20	20
MISO Z6 Solar Project	0	0	0	0	0	0	0	0	0	0
Planned Gas - CT	0	0	0	0	0	0	0	0	0	0
Planned Gas - CC	0	0	0	0	0	0	0	0	0	0
Planned Solar	0	0	0	0	0	0	0	0	0	0
Total Resources	1,108	1,108	1,107	821	821	821	820	816	816	816
Total Peak + Reserves	1,296	1,301	1,306	1,351	1,359	1,364	1,369	1,374	1,380	1,386

*Does not include a planned 75 MW offtake from the Alta Farms Wind Farm

The table below shows the preferred plan after capacity additions.

Table 20 Preferred Portfolio – ICAP* – ELCC

Resource/Year	PY 21-22	PY 22-23	PY 23-24	PY 24-25	PY 25-26	PY 26-27	PY 27-28	PY 28-29	PY 29-30	PY 30-31
Existing Gas - CT	373	373	373	373	373	373	373	373	373	373
Existing Coal	609	609	609	609	609	454	454	454	454	454
Existing Bi-lateral	246	271	271	271	271	196	196	196	196	196
IMPA Solar	53	51	46	37	36	34	34	34	34	34
Ratts Solar PPA	0	0	53	38	35	32	32	32	32	31
Incremental Solar PPA	0	0	0	25	23	21	21	21	21	21
MISO Z6 Solar Project	0	0	0	0	23	21	21	21	21	21
Planned Gas - CT	0	0	0	0	0	196	196	196	196	196
Planned Gas - CC	0	0	0	0	0	0	0	0	0	0
Planned Solar	0	0	0	0	0	0	0	0	0	0
Total Resources	1,281	1,304	1,351	1,352	1,369	1,327	1,327	1,327	1,326	1,325
Total Peak + Reserves	1,255	1,252	1,254	1,259	1,262	1,273	1,274	1,278	1,283	1,290

Resource/Year	PY 31-32	PY 32-33	PY 33-34	PY 34-35	PY 35-36	PY 36-37	PY 37-38	PY 38-39	PY 39-40	PY 40-41
Existing Gas - CT	373	373	373	373	373	373	373	373	373	373
Existing Coal	454	454	454	364	364	364	364	364	364	364
Existing Bi-lateral	196	196	196	0	0	0	0	0	0	1
IMPA Solar	34	33	33	33	33	33	33	31	31	31
Ratts Solar PPA	31	30	30	30	30	30	30	28	28	28
Incremental Solar PPA	21	21	21	21	21	21	21	20	20	20
MISO Z6 Solar Project	21	21	21	21	21	21	21	20	20	20
Planned Gas - CT	196	196	196	196	196	196	196	196	196	196
Planned Gas - CC	0	0	0	208	208	208	208	208	208	208
Planned Solar	0	0	0	21	21	21	21	20	20	20
Total Resources	1,325	1,325	1,324	1,267	1,267	1,267	1,266	1,260	1,260	1,260
Total Peak + Reserves	1,296	1,301	1,306	1,351	1,359	1,364	1,369	1,374	1,380	1,386

*Does not include a planned 75 MW offtake from the Alta Farms Wind Farm

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15 SHORT TERM ACTION PLAN

15.1 ACTION (S) REQUIRED TO IMPLEMENT THE PLAN

IMPA is planning for the eventual retirement of Gibson 5 in PY 26-27. However, in the immediate term, assuming MISO capacity accreditation remains unchanged, IMPA should be in a relatively flat capacity position until the retirement of Gibson 5. As the preferred plan set forth above includes replacing Gibson 5 capacity with a natural gas combustion turbine and solar projects, the action items are as follows:

Action Plan Items

1. Continue IMPA Solar Park Program
2. Work with the Gibson 5 partners regarding the plan, timing and cost for retirement of the unit.
3. Begin internal planning for the best path forward for adding CT capacity to its portfolio as a replacement for Gibson 5
4. Maintain regular contact with the marketplace for both financial power and physical solar power in order to optimize IMPA's energy position prior to the expiration of the ITC for solar
5. Explore incremental opportunities for solar off-take as part of the modeled, least cost solution
    a. Analyst cost/benefit of PPA offtake vs. Agency ownership of utility scale solar
6. Continue the IMPA Energy Efficiency Plan
7. Continue to utilize the RTO/ISO stakeholder process to monitor market rules regarding renewable capacity accreditation and resource adequacy
8. Monitor elections and the legislative process to remain informed on future environmental policy as it pertains to CO_2
9. Continue to enhance IMPA's modeling capabilities with respect to transmission, capacity/market price formation, and portfolio optimization
    a. To this end, survey the energy software industry to seek potential model alternatives.

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16 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. G1 - 2019 IMPA Annual Report
   G2 - 2019 IMPA Annual Report - Financials
H. IRP Summary Document