INDIANAPOLIS POWER & LIGHT COMPANY

2019 Integrated Resource Plan

Volume 1 of 3

December 16, 2019

Table of Contents

Table of Figures

Acronyms List

A

AC	Alternating Current
ACEEE	American Council for an Energy Efficient Economy
ACESA	American Clean Energy and Security Act of 2009
ACI	Activated Carbon Injection
ACLM	Air Conditioning Load Management
AFUDC	Allowance for Funds used During Construction
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
ARRA	American Recovery and Reinvestment Act of 2009
ARS	Automatic Resource Selection
ASM	Ancillary Services Market
ATC	Available Transfer Capability or Capacity

B

BA	Balancing Authority or Balancing Area
BACT	Best Available Control Technology
BES	Bulk Electric System
BESS	Battery Energy Storage System

C

C&I	Commercial and Industrial
CAA	Clean Air Act – EPA issued initial rules in 1970
CAAA	Clean Air Act Amendments – 1990
CAGR	Compound Annual Growth Rate
CAIR	Clean Air Interstate Rule
CC	Combined Cycle
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals – EPA issued rules June 2010
CCS	Carbon Capture and Sequestration or Carbon Capture and Storage
CCT	Clean Coal Technology
CDD	Cooling Degree Days
CFL	Compact Fluorescent Lighting
CHP	Combined Heat & Power
CIP	Critical Infrastructure Protection
CO_2	Carbon Dioxide
CONE	Cost of New Entry
CPCN	Certificate of Public Convenience and Necessity
CPP	Clean Power Plan
CPW	Cumulative Present Worth
CVR	Conservation Voltage Reduction
CSPAR	Cross State Air Pollution Rule – EPA issued rules July 2011
CT	Combustion Turbine

D

DA	Distribution Automation, or Day Ahead Scheduling
DG	Distributed Generation
DR	Demand Response
DSI	Dry Sorbent Injection
DSM	Demand-Side Management

E

ECS	Energy Control System
EE	Energy Efficiency
EFOR	Equivalent Forced Outage Rate
EFORd	Equivalent Forced Outage Rate demand
EIA	Energy Information Administration of the U.S. Department of Energy
ELCC	Electric Load Carrying Capability
ELG	National Effluent Limitation Guidelines
EM&V	Evaluation, Measurement and Verification
EPA	U.S. Environmental Protection Agency
ESP	Electrostatic Precipitator
EV	Electric Vehicles

F

FAC	Fuel Adjustment Clause
FEED	Front End Engineering Design
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization

G

GDP	Gross Domestic Product
GHG	Green House Gas

H

HAP	Hazardous Air Pollutant
HDD	Heating Degree Days
Hg	Mercury
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning

I

ICAP	Installed Capacity
IEEE	Institute of Electrical and Electronics Engineers
IGCC	Integrated Gas Combined Cycle
IMM	Independent Market Monitor
IRP	Integrated Resource Planning
ISO	Independent System Operator
IURC	Indiana Utility Regulatory Commission

K

kWh	Kilowatt hour

J

JCSP	Joint Coordinated System Planning

L

LAER	Lowest Achievable Emission Rate
LCOE	Levelized Cost of Energy
LMR	Load Modifying Resource
LMP	Locational Marginal Pricing
LNB	Low NO_x Burner
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LSE	Load Serving Entity

M

MACT	Maximum Achievable Control Technology
MATS	Mercury and Air Toxics Standard
MFDI	Multi Family Direct Install
MISO	Midcontinent Independent System Operator
MPS	Market Potential Study
MSA	Metropolitan Statistical Area
MTEP	Midcontinent ISO Transmission Expansion Planning
MVA	Mega Volt Ampere, Mega Volt Amplifier, or Multivariate Analysis
MVP	Multi-Value Projects (transmission for both reliability and economic benefits)
MW	Megawatt

N

NAAQS	National Ambient Air Quality Standard – EPA issued rules January 2013
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation (formerly Council)
NG	Natural Gas
NID	Net Internal Demand
NIST	National Institute of Standards and Technology
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NYMEX	New York Mercantile Exchange

O

O&M	Operations and Maintenance
OSM	Office of Surface Mining

P

PC	Pulverized Coal
PCT	Participant Cost Test (see EM&V)
PHEV	Plug-In Hybrid Electric Vehicle
PJM	PJM LLC (Regional Transmission Organization)
$PM_{2.5}$	Particulate Matter that is 2.5 micrometers in diameter or smaller
PPA	Purchase Power Agreement

PRM	Planning Reserve Margin
PRMR	Planning Reserve Margin Requirement
PV	Photovoltaic
PVRR	Present Value Revenue Requirement

R

RCRA	Resource Conservation and Recovery Act (coal ash disposal regulations)
REC	Renewable Energy Credit
REP	Renewable Energy Production
RES	Renewable Energy Standards
RF, RFC	ReliabilityFirst, Reliability First Corporation
RFP	Request for Proposals
RIIA	Renewable Impact Integration Assessment
RIM	Rate Payer Impact Measure (see EM&V)
RTO	Regional Transmission Organization (Independent System Operator)

S

SAE	Statistically Adjusted End Use
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCPC	Super Critical Pulverized Coal
SCR	Selective Catalytic Reduction (pollution control)
SIP	State Implementation Plan (environmental)
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide

SREC	Solar Renewable Energy Credit

T

TBEL	Technology Based Effluent Limits
TOU	Time of Use
TRC	Total Resource Cost Test
TW	Terawatt

U

UCAP	Unforced Capacity
UCT	Utility Cost Test

V

VAR	Volt Ampere Reactive, Variance, or Value at Risk

W

WQBEL	Water Quality Based Effluent Limits

X

XEFORd	Equivalent demand Forced Outage Rate excluding causes Outside of Management Control

Executive Summary

170 IAC 4-7-4(24)

The 2019 Integrated Resource Plan (“IRP”) was developed in an environment with expectations for unprecedented technological change and power market evolution over the planning horizon. Changing customer preferences and expectations, declining costs of renewables and storage, a changing regional resource mix, and the growing importance of carbon reduction have all played into IPL’s planning strategy and process for this IRP.

IPL’s 2019 IRP process and preferred resource portfolio meet four core company objectives and areas of focus:

Customer Centricity

Focuses on customer needs and wants

IPL’ s Preferred Resource Portfolio delivers safe, reliable, and economic electricity to customers at just and reasonable rates. IPL conferred with customers and various stakeholders throughout its evaluation and in advancing its recommendation to the Indiana Utility Regulatory Commission. The Preferred Resource Portfolio best serves IPL customers today and into the future, contemplates customers’ evolving energy needs, and relies on data-driven models.

Economics

Considers optimal current and expected market economics

IPL’s Preferred Resource Portfolio is based on known and forecasted market economics, potential risks modeled across a wide range of futures, and stakeholder input. Replacement resource additions will be selected based upon an all-source competitive process with detailed regulatory filings before the Commission.

Flexibility & Balance

Measured approach maintaining optionality

Preserving flexibility and optionality benefits customers. IPL is pursuing a gradual approach, and only planning to retire units where the option value is not economically prudent. A phased retirement approach with smaller capacity impacts over time mitigates large rate impacts and exposure to the market. Further, a more diverse, scalable and balanced fleet helps protect against fuel price swings and capacity factor variances of different generation sources. Simply put, diverse fleets optimize the customer position in varying economic and political scenarios.

Greener Energy Future

Moves the company to more renewables

IPL continues to invest in its existing thermal generation to the extent it makes economic sense for customers while at the same time preparing for the evolving role of renewable generation. The cost of renewables will generally continue to decline, and customers are increasingly demanding cleaner sources of energy. IPL's Preferred Resource Portfolio is the reasonable least cost option, which also provides a cleaner and more diverse generation mix for customers.

The 2019 IPL Preferred Resource Portfolio contains the following elements:

- **Retirement of 630 MW of coal by 2023**: Based on extensive modeling, IPL has determined that the cost of operating Petersburg ("Pete") Units 1 and 2 exceeds the value customers receive compared to alternative resources. Retirement of these units allows the company to cost-effectively diversify the portfolio and transition to cheaper and cleaner resources while maintaining a reliable system.
- **Competitive bid(s) request for approximately 200 MW of replacement capacity**: IPL intends to issue an all-source Request for Proposal ("RFP") in order to competitively procure replacement capacity by June 1, 2023, which is the first year IPL is expected to have a capacity shortfall. IRP modeling indicates that a combination of wind, solar, storage, and energy efficiency would be the lowest cost options for the replacement capacity, but IPL will assess the type, size, and location of resources after bids are received.
- **Target approximately 130,000 MWh per year of demand side management (DSM) and energy efficiency programs:** IPL plans to continue to be a state leader in DSM implementation and will target approximately 130,000 MWh per year of DSM in the 2021-2023 plan.
- **Maintain safe, reliable, cost effective generation at Petersburg:** IPL conducted a holistic evaluation of the economics of each coal unit in our fleet. While systemic changes in wholesale power markets are impacting the viability of coal in MISO, Pete 3 and 4 provide firm, dispatchable capacity and maintaining those units preserves optionality in the face of uncertainty over the next five years. The IRP process is every three years, and IPL has established a robust and transparent process for evaluating the future cost effectiveness of the remaining coal units through time. IPL will closely monitor market forces, federal and state regulation, and other industry trends that could impact the future economics of our remaining coal units.

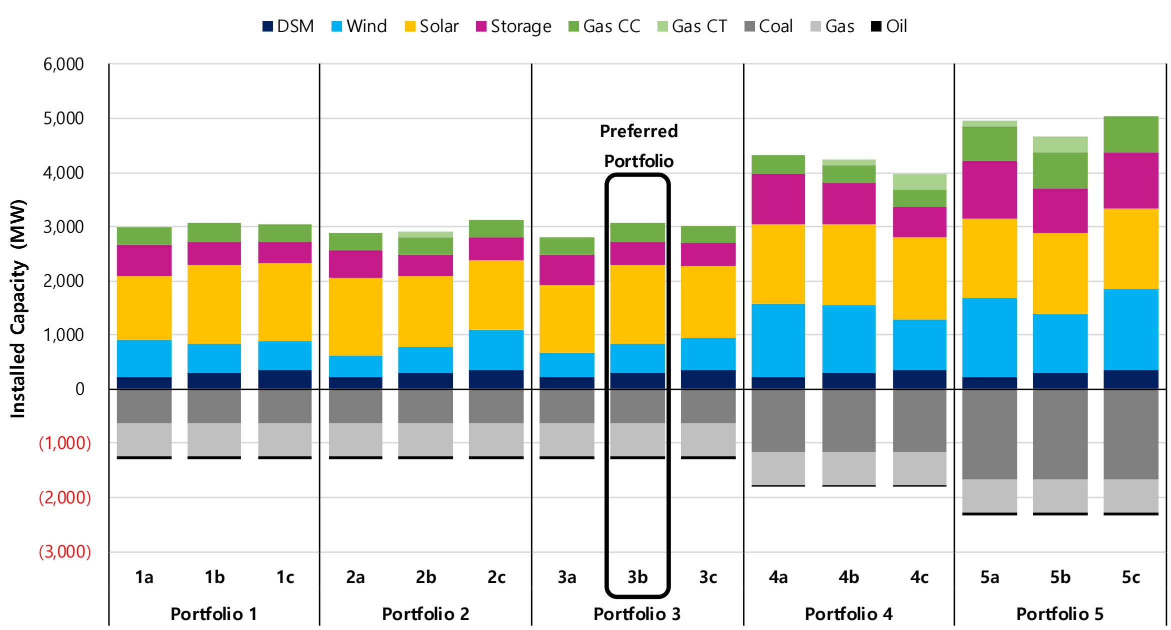
2019 IRP Modeling

IPL evaluated a set of fifteen (15) candidate resource portfolios created from a modeling process that incorporated an evaluation of coal retirement dates, DSM market potential, and new resource economics in a probabilistic optimization framework. The candidate resource portfolios were stressed across a wide range of scenarios, which allowed IPL to identify the portfolio that mitigates risk and performs the best across multiple futures.

IPL held five public stakeholder meetings and other technical meetings, continuing to build upon the stakeholder process in the 2016 IRP. IPL provided detailed modeling assumptions early in the process, allowing for meaningful feedback and discussion about inputs and methodology. The company utilized public data when possible to provide transparency, and confidential data was provided to interested stakeholders, consistent with Non-Disclosure Agreements.

IPL's Preferred Resource Portfolio, highlighted in Figure A, adds over 1,000 MW of wind, solar, storage, and DSM by 2030 and over 3,000 MW by 2039. The retirement of Petersburg Units 1 and 2 by 2023 allows IPL to take advantage of expiring tax credits for wind and solar, which benefits customers in both the short term and long term.

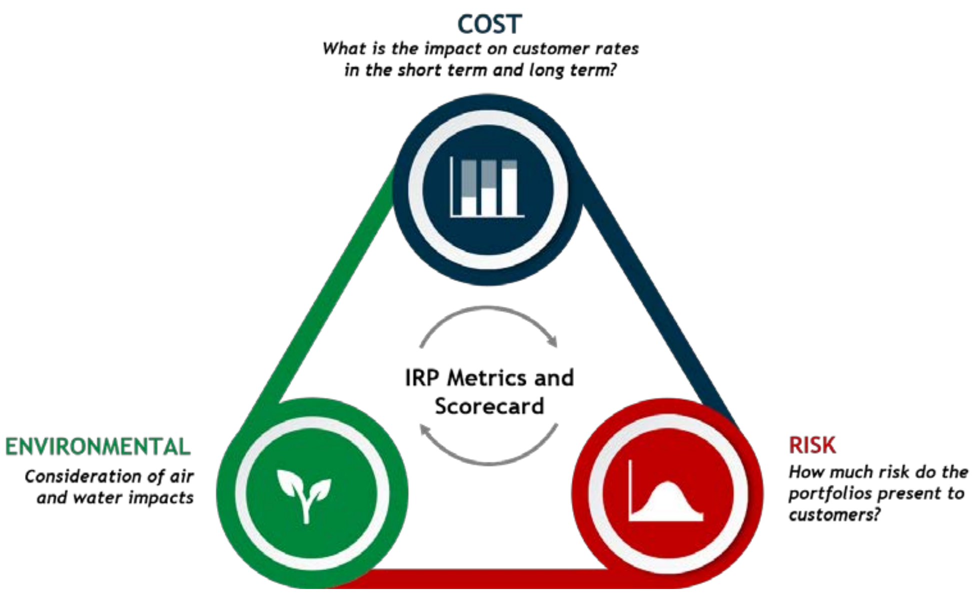
Figure A | Candidate Portfolios: Cumulative Capacity Changes through 2039



IRP Modeling Results Summary

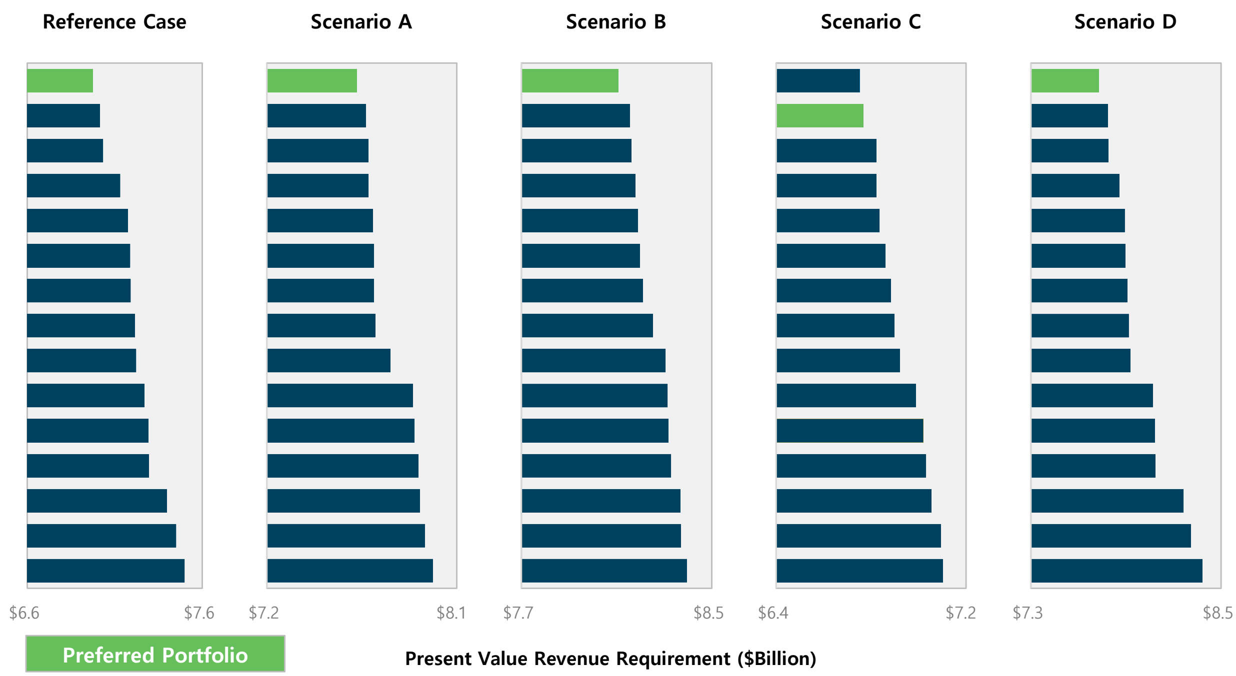
The decision criteria for selecting the Preferred Resource Portfolio (Figure B) was based on a comprehensive set of stakeholder informed modeling and analysis and comparison of each portfolio on attributes for cost, risk, and environmental impact. Additionally, IPL considered other qualitative factors in to the decision, including employee and community impact, the ability of the plan to react to changing market conditions, and the risks that each portfolio could introduce to IPL customers.

Figure B | 2019 IRP Portfolio Metrics Foundation



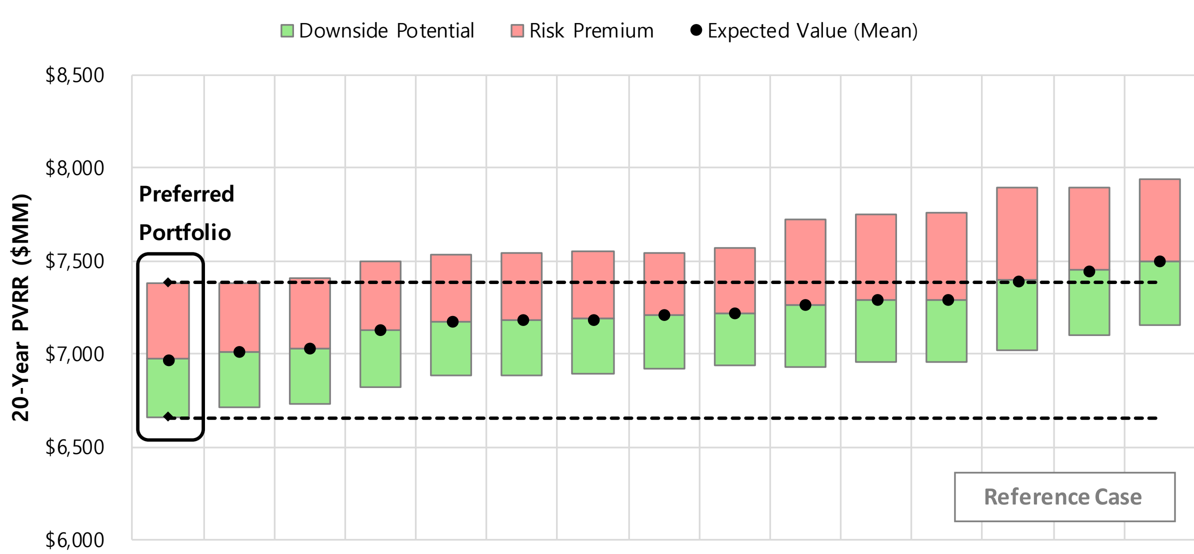
As shown in Figure C, the Preferred Resource Portfolio was the lowest cost portfolio across multiple scenarios and provides a balance of long-term portfolio savings and mitigation of short term rate impacts. Economic retirements of Pete 1 and 2 will create cost savings that can be used to offset the cost of replacement capacity. In modeling sensitivities on the cost of replacement capacity, IPL found that the Preferred Resource Portfolio is the lowest cost plan even if the cost of replacement resources is higher than what we currently forecast. Overall, the Preferred Resource Portfolio, which retires two coal units by 2023 and fills the capacity shortfall with a mix of DSM, wind, solar, and storage, is the lowest cost plan for IPL customers.

Figure C | Preferred Resource Portfolio: Lowest Cost Across Wide Range of Scenarios



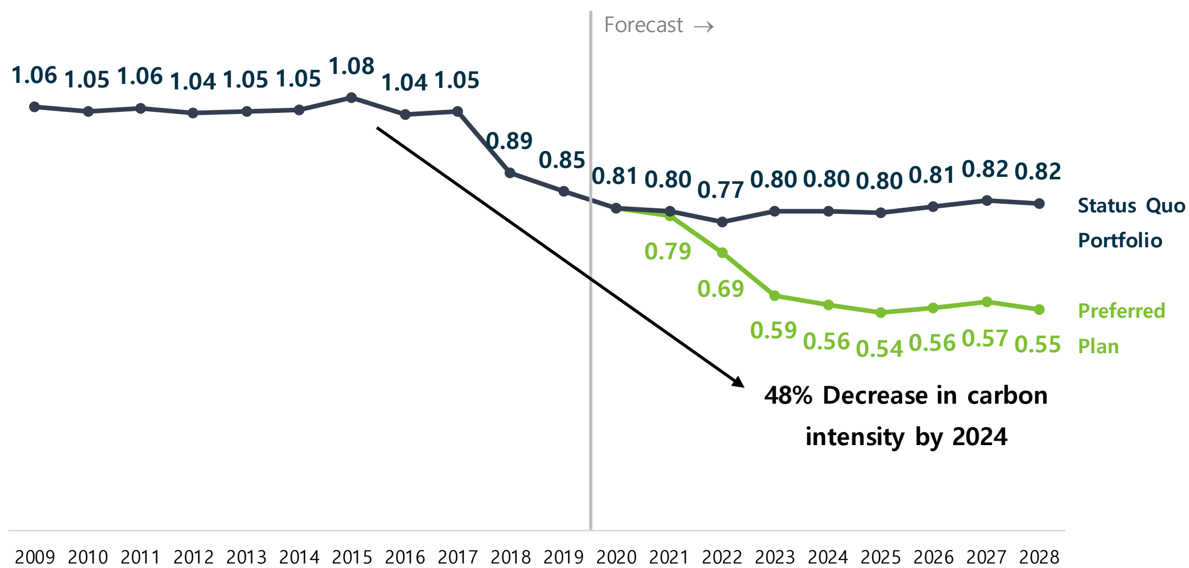
Through IPL's robust modeling effort that incorporated risk and uncertainty with stochastic modeling of weather, load, renewable profiles, and commodity prices, we were able to effectively build risk analysis into the entire modeling framework and decision analysis in this IRP. The variations in modeling assumptions applied probabilistically across multiple scenarios created a wide range of uncertainty considered. Figure D shows that the Preferred Resource Portfolio provides the optimal tradeoff of risk and cost for IPL customers.

Figure D | Preferred Resource Portfolio Lowest Cost on Risk-Adjusted Basis



In addition to benefits of being the lowest cost and least risk plan, the Preferred Resource Portfolio also allows IPL to significantly improve our carbon footprint and continue our decade-long efforts for portfolio diversification and decarbonization. As shown in Figure E, over the course of a 10-year period (2014-2023), IPL will be able to reduce our carbon intensity by almost 50% while at the same time providing our customers with future cost-effective carbon mitigation strategies.

Figure E | IPL Carbon Intensity, 2009 – 2028 (tons/MWh)



Section 1: Introduction

Indianapolis Power & Light Company ("IPL") is engaged primarily in generating, transmitting, distributing and selling electric energy to more than 500,000 retail customers in Indianapolis and neighboring areas; the most distant point being about 40 miles from Indianapolis. IPL's service area covers about 528 square miles. IPL is subject to the regulatory authority of the Indiana Utility Regulatory Commission ("IURC") and the Federal Energy Regulatory Commission ("FERC"). IPL fully participates in the electricity markets managed by the Midcontinent Independent System Operator ("MISO"). IPL is a transmission company member of Reliability First ("RF"). RF is one of eight Regional Reliability Councils under the North American Reliability Corporation ("NERC"), which has been designated as the Electric Reliability Organization under the Energy Policy Act of 2005 ("EPAct"). IPL is part of the AES Corporation, a Fortune 500 global power company, with a mission to improve lives by accelerating a safer and greener energy future.

Every three years, IPL submits an Integrated Resource Plan ("IRP") to the IURC in accordance with Indiana Administrative Code (IAC 170 4-7) to describe expected electrical load requirements, a discussion of potential risks, possible future scenarios and a preferred resource portfolio to meet those requirements over a forward-looking 20-year study period based upon analysis of all factors. This process includes input from stakeholders known as a "Public Advisory" process.

The IRP is viewed as a guide for future resource decisions made at a snapshot in time. Resource decisions, particularly those beyond the five-year horizon, are subject to change based on future analyses and regulatory filings. New resource additions, including supply-side and demand-side resources, may require regulatory approval.

1.1 IRP Objective

170 IAC 4-7-4(24)

The objective of IPL's IRP is to identify a preferred resource portfolio to provide safe, reliable, sustainable, and reasonable least cost energy service to IPL customers. The study period for this IRP is 2020-2039, giving due consideration to potential risks and stakeholder input.

IPL engaged in a bottom-up review of every modeling assumption and modeling approach from the 2016 IRP in preparation for this IRP. Through five public stakeholder meetings and three technical workshops, IPL developed the assumptions and modeling framework in an open, transparent, and fact-based manner that considered a wide range of factors facing IPL's generation fleet over the next 20 years. A robust analytical process coupled with qualitative risk analysis contributed to the selection of the preferred resource portfolio.

1.2 Guiding Principles

IPL's guiding principles describe more fully its decision analysis process:

1. IPL will comply with IURC Orders, Indiana Administrative Code ("IAC") requirements, North American Electric Reliability Council ("NERC") reliability standards and FERC approved MISO tariffs.
2. Cost estimates for supply-side resources were based on a thorough analysis of cost estimates from multiple sources and benchmarked to recent public all-source RFP information. Demand-side management cost estimates were based on a detailed MPS report built up from the measure level.
3. Demand Side Management ("DSM") modeling included traditional capacity expansion modeling as well as an incremental decrement analysis.
4. IPL plans to continue to offer cost-effective DSM programs that are inclusive for customers in all rate classes while appropriate for our market and customer base, modify customer behavior, and provide continuity from year to year.

IPL assumed the following parameters remain constant in the IRP study period of 2020-2039. Should these change in the future, the analyses subsequent to the 2019 IRP may vary.

- Regulatory framework remains – This IRP assumes current regulatory frameworks for IPL based on the IURC and FERC scopes of jurisdiction.
- MISO capacity construct – While IPL is aware of MISO's plans to propose tariff changes to its capacity construct with FERC via the recent Resource Availability and Need (RAN) process, the specific details are not yet known and the filing not yet complete. Therefore, the resource capacity requirements for this study period are based upon the current construct.
- MISO interaction – IPL will continue to engage in the MISO stakeholder process to influence tariff and business practice changes to benefit customers.
- Distributed Generation – Distributed Generation ("DG") is synchronized with the distribution grid as a best safety practice and designed to align with system requirements to support no production curtailment such as might occur with wind resources connected to a transmission system.

IPL recognizes the following items may initiate future changes in its resource portfolio.

- Technology improvements – All resource technologies will likely improve in performance. The model assumes known factors today and projected cost forecasts based on industry knowledge.
- Future elections – Policy changes may follow national, state and local election results in the next few years.
- Stakeholder sustainability interests – As discussed in multiple stakeholder forums within the IRP public advisory process, regulatory proceedings, customer meetings, and investor interactions in the normal course of business, IPL recognizes the potential for continued pressure to change its resource mix in response to advocates' interests in cleaner sources of energy.
- Environmental regulations – the largest driver of portfolio value in modeled scenarios involved the impact of a carbon tax in scenarios. While no federal carbon tax exists, public pressure, proposed legislation, and corporate support for carbon pricing has led us to include a carbon tax as a proxy for future carbon legislation. The carbon tax level and formation of prices could vary significantly. Any future IRPs will incorporate changes in the state and federal environmental landscape.

IPL will monitor these developments and incorporate changes in subsequent IRP analyses.

1.3 2019 IRP Improvements

IPL has incorporated changes in its 2019 IRP based on stakeholder feedback from its 2016 IRP. Changes are summarized in Figure 1.1.

Figure 1.1 | Targeted IRP Improvements

Topic	Comments Summary (not exhaustive)	2019 IRP Improvements
Commodity Forecasts	• Not enough narrative and underlying fundamental support data to support commodity price forecasts • Base forecast inconsistent with changing market fundamentals and trends • Changing resource mix and other fundamentals could materially change	• Scenarios will be built around varying commodity assumptions, with all supporting data clearly outlined • Narrative and thorough set of supporting data will be provided well in advance of IRP filing date • Data will be made available with signed NDA and public whenever possible
Scenarios and Portfolios	• Unclear modeling framework with regards to scenarios, portfolios, and stochastics • All portfolios weighed against base case assumptions • Preferred plan not optimized in capacity expansion	• Comprehensive scenario modeling framework designed to address concerns in 2016 IRP • Modeling types will be clearly identified and discussed (i.e. portfolios vs scenarios, optimized vs fixed portfolios, capacity expansion vs production cost model)
Metrics	• Stochastic results not fully integrated with metrics scorecard and used in a limited manner • No specific metrics related to portfolio diversity • Environmental metrics should also include land and water impacts	• Move to Ascend Analytics' PowerSimm enabled IPL to more fully incorporate stochastic results into the metrics process • Metrics and risk analysis will be conducted using the same set of underlying data from PowerSimm • IPL will consider additional environmental metrics
DSM/EE Modeling	• Assumptions on future DSM costs need to be reviewed	• New model will allow for more DSM bundles and decision points • IPL considering alternative approaches to accounting for changes in future DSM costs

The IRP results include potential candidate future resource portfolios considering uncertainties and risk factors identified to date. Subsequent resource changes which may result after the submission of IRPs will be based upon further analysis and specific competitive processes with detailed regulatory filings before the IURC.

1.4 Stakeholder Engagement

170 IAC 4-7-4(30)

The 2019 meeting series included discussions of the IRP process, modeling assumptions, data inputs, modeling DSM, scenario development, sensitivity analysis, modeling results, and metric analysis to compare portfolios. IPL incorporated stakeholder suggestions throughout the process, such as completing a DSM decrement analysis. Furthermore, IPL provided data releases of detailed modeling assumptions early in the IRP process. The first release was on April 19, 2019 (Data Release #1). Followed by Data Release #2 (May 14, 2019), Data Release #3 (June 21, 2019), Data Release #4 (October 28, 2019), Data Release #5 (November 6, 2019), and Data Release #6 (November 14, 2019).

IPL engaged in discussions with individual stakeholders and its Advisory Board. Prior to Public Advisory Meetings, IPL met with technical stakeholders who executed a Nondisclosure Agreement ("NDA") with IPL regarding IRP information. In these technical workshops, IPL provided data files and discussed modeling status and results. IPL approached stakeholders early and often for ample discussion and time for feedback.

Discussions proved to be quite productive and facilitated dialogue among stakeholders prior to the IRP filing. Public Advisory Meeting materials are provided as Attachment 1.2.

1.5 Contemporary Issues

170 IAC 4-7-4(17)

IPL participates in the Commission's IRP Contemporary Issues Technical Conference held each year. In 2019, the Conference was held on April 15, 2019. IPL Director of Resource Planning, Patrick Maguire, was a panelist on the topic of "Utilization and Maintenance of Massive Data Bases" and IPL Director of T&D Operations, Mike Holtsclaw, was a panelist on the topic of "Integration of DERs into Distribution System Planning and IRPs". The Conference also covered topics such as load shapes, the changing availability and flexibility requirements of MISO, long-term utility planning assumptions and procurement decisions, preliminary lessons learned from NIPSCO's all-source RFP, risk analysis and life cycle analysis of greenhouse gas emissions.

Section 2: Resource Adequacy and Transmission Planning

170 IAC 4-7-6(a)(5) 170 IAC 4-7-6(b)(4)(D)170 IAC 4-7-6(b)(4)(E)

2.1 Resource Adequacy

To be resource adequate, a utility must possess enough resources to satisfy forecasted future loads. The IRP process focuses on developing potential resource portfolios needed to meet two different types of customer needs: energy use and peak demand. Annual energy use is measured in MWh to reflect the accumulation of electricity used over time. Annual peak demand is the measure of the highest hour of usage for the year and is measured in MW. The Resource Adequacy analysis serves as the foundation of the IRP process to create resource portfolios to meet the annual forecasted peak demand throughout the 20-year study period. Energy contributions of each resource are dependent upon the economic dispatch model results in individual scenarios. Each scenario includes a set of input assumptions which are based upon varying potential futures and related risks such as commodity prices and increased or decreased load growth. The scenarios are described in Section 7 of this IRP.

2.1.1 Reserve Margin Criteria

When planning to meet future peak needs, utilities input the expected (forecasted) peak demand, plus an appropriate Planning Reserve Margin ("PRM"). PRMs are necessary to account for two primary uncertainties: forecast uncertainty and resource availability uncertainty.

MISO calculates an Installed Capacity ("ICAP") PRM and an Unforced Capacity ("UCAP") PRM. The ICAP PRM is higher than the UCAP PRM because it does not account for generator outage events that translate into a unit's Equivalent Forced Outage Rate Demand ("xEFORd"). For the 2019-2020 MISO Planning Year, the ICAP PRM is 16.8% and the UCAP PRM is 7.9%. IPL's capacity expansion model accounts for individual units' xEFORd, and therefore uses the UCAP PRM, or 7.9%. This more accurately reflects how IPL's assets participate in MISO's Planning Resource Auction.

MISO defines a Planning Year in seasonal terms of June 1 through May 31. The 7.9% PRM is based on Loss of Load Expectation ("LOLE") Studies performed annually by MISO and applied across the footprint.[1] LOLE Studies are used to determine an appropriate PRM given many factors including the forecast uncertainty and resource availability uncertainty across the MISO footprint. Consideration is given to historic forecast error, historic unit unavailability at time of peak, the type and size of

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[1] MISO's most recent LOLE study may be found at this link: https://cdn.misoenergy.org/20180911%20LOLEWG%20Item%2002%202019-20%20PY%20LRR%20%20PRM273420.pdf

generating units and other resources, and the transmission system configuration. MISO uses load forecast information from Load Serving Entities ("LSEs") coupled with the previous calendar year actual system peak to determine coincidence factors for subsequent year planning purposes in the LOLE process. The coincident peak factor measures how closely IPL's specific peak load aligns with the MISO footprint peak load. For 2020, the IPL coincidence peak factor is 97.33% and is used throughout the IRP study period. IPL multiplies the peak load by 0.9733 to account for IPL's peak load being shifted slightly from MISO's peak load.

The MISO LOLE Studies produce a PRM that when applied to all the peak load forecasts in the MISO footprint results in an expectation of one loss of load event once every 10 years. That is, if all utilities in the MISO footprint carried an average of 7.9% reserves, the expectation would be that once every 10 years there would be a loss of load event somewhere in the footprint resulting from peak load exceeding resources available at peak. The LOLE study accounts for generation and transmission reliability impacts. Actual reserve margins will vary annually in part due to the "lumpy" nature of adding resources, load variances and other factors.

2.1.2 Resource Capacity Credit

Resource capacity that is planned to meet the Planning Reserve Margin Requirement ("PRMR") is calculated differently for varying technologies. The PRM is used to cover uncertainty related to both unavailability of traditional resources and forecast error. Resource capacity credits are based upon MISO business practices in terms of ICAP and UCAP.[2] For thermal units, ICAP is based upon annual maximum unit capability test results, also called the Generation Verification Test Capacity ("GVTC"). UCAP is calculated from the ICAP value, the results of annual GVTC and a 3-year rolling average of the xEFORd.

Wind capacity credit is calculated from its Effective Load Carrying Capability ("ELCC") which accounts for the probabilistic shortfalls of wind generation coinciding with peak load in the MISO footprint. Due to the mismatch of low wind production during high load periods, wind is given a much lower capacity credit than thermal generation. MISO's latest study for Indiana (Zone 6) indicates an ELCC of 7.8%.[3] All resources must have firm transmission to receive capacity credit. IPL has firm transmission for Hoosier Wind Park but not for Lakefield Wind Farm, so it only receives capacity credit for Hoosier Wind Park.

[2] For more detail see MISO Business Practices Manual (BPM-11) at this link: https://www.misoenergy.org/legal/business-practice-manuals/

[3] https://cdn.misoenergy.org/2019%20Wind%20and%20Solar%20Capacity%20Credit%20Report303063.pdf.

Similarly, production from solar units at time of peak load have proven to be less than traditional thermal unit production. MISO currently gives solar a capacity credit of 50%, which is approximately the capacity credit applied to the 96 MW of solar generation under contract in IPL's service territory. The contracted solar is connected to the IPL distribution system and reduces its load requirements and associated PRMR rather than being offered as a resource in the MISO market. Increased penetration of solar in the MISO footprint will change the net load profile and dictate a lower capacity credit over time. IPL has accounted for this and it is covered in more detail in Section 5.

Demand response resource capacity credit is based upon the capability of the resource to contribute to peak demand reductions for a minimum of four hours based on engineering estimates or field testing. IPL is modeling 55 MW of UCAP capacity from demand response resources. These resources provide capacity credit through the Air Conditioning Load Management ("ACLM") program, Conservation Voltage Reduction ("CVR") program, and Rider 17 of IPL's tariff. These programs contribute 38.6 MW, 15.3 MW, and 1.1 MW respectively and are considered Load Modifying Resources ("LMRs") in MISO.

IPL does not include capacity credit for its existing Battery Energy Storage System ("BESS"). While it has the capability to provide capacity credit, IPL operates the BESS to provide Primary Frequency Response and other reliability services.

2.1.3 The MISO Capacity Construct

While IPL's IRP process is used to develop long term plans for providing the energy and capacity needs of IPL's customers, IPL also participates in MISO's resource adequacy (or capacity) construct as outlined in Module E-1 of MISO's FERC approved tariff.[4] IPL, not MISO, is responsible for resource adequacy and developing long term resource plans per 170 IAC 4-7.

Since MISO's capacity adequacy construct is focused on the short term (one planning year), its focus is on existing resources and does not plan for resources in the future.

Each November each LSE provides MISO with a peak demand forecast for the following Planning Year. MISO adds a reserve margin, based on its most recent LOLE Study, and adds MW to cover expected transmission losses to produce each LSE's PRMR.

MISO conducts an auction each April, and if an LSE has resources in the MISO accounting system equal to its PRMR, then that LSE will not be billed capacity costs in the auction. If an LSE has less capacity than its PRMR in the MISO capacity accounting system at the time of the auction it will be assessed

[4] MISO FERC Approved Tariff can be found at https://www.misoenergy.org/legal/tariff/.

capacity costs by MISO for its shortage in the auction. If an LSE or other type of Market Participant has more capacity than PRMR, it may receive revenues from the excess capacity in the auction.

In addition to owning a resource with capacity credit, an LSE can also purchase or sell capacity through the bilateral market in order to meet its PRMR. By allowing resource owners and LSEs to buy and sell capacity credits from each other, and at the same time requiring that each LSE meet its PRMR with an appropriate number of capacity credits prior to the summer, the MISO capacity construct allows utilities to optimize their investments and not exactly meet their PRMR with their own resources. Figure 2.1 describes the PRMR calculation. Figure 2.1 illustrates the PRMR for IPL for a single year.

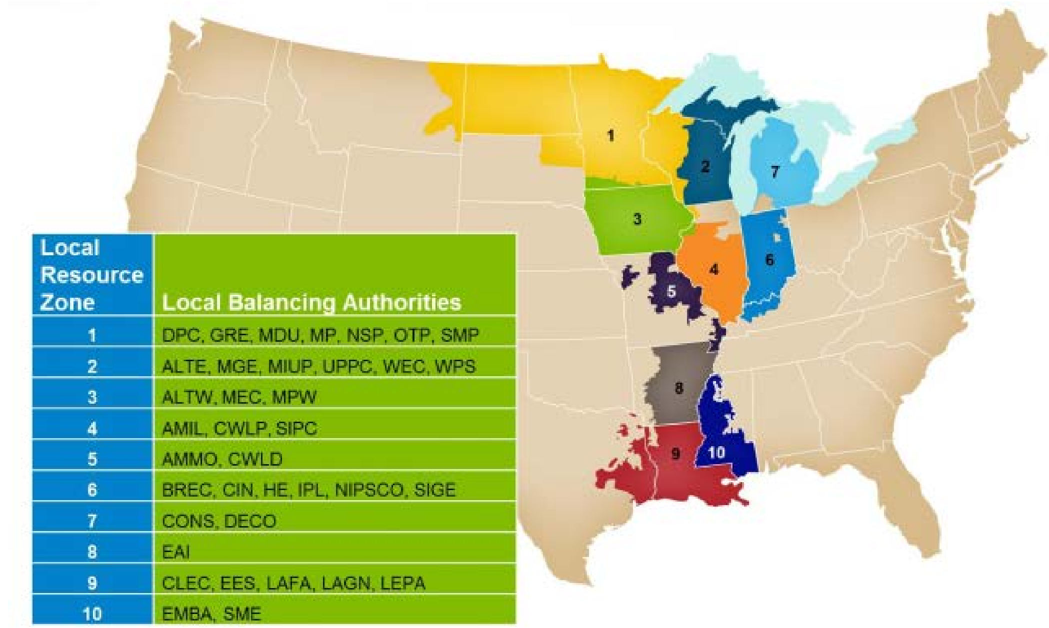
Figure 2.1 | Illustrative Example – Annual Reserve Margin Requirement Calculation

(A)	Non-Coincident IPL Peak Load Forecast	3,003 MW	
(B)	IPL Coincident Peak Factor	97.33%	
(C)	IPL Coincident Peak Load Forecast	2,923 MW	(C) = (A)*(B)
(D)	Losses	2.1%	
(E)	IPL Peak Load Forecast	2,985 MW	(E) = (C)*(1+D)
(F)	MISO Planning Reserve Margin	7.9%	
(G)	Final IPL Planning Reserve Margin Requirement	3,220 MW	(G) = (E)*(1+F)

By holding each LSE accountable for meeting its PRMR, MISO can be assured that the resources will meet or exceed the forecasted MISO demand and reserve margin as determined in MISO's annual LOLE study.

MISO established zones for it auction framework as shown in Figure 2.2. IPL is in Zone 6.

Figure 2.2 | MISO Zones [5]



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP, OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, IPL, NIPSCO, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

If all LSEs satisfied their PRMR with resources from the Zone in which their load resides the Zones would not be needed. But since the auction sometimes uses resources from one zone to meet the needs in another zone the auction must establish and honor transport limits between zones. Honoring transport limits can result in clearing prices being different for different zones. MISO's capacity construct has resulted in varying prices by zone over the past several years.

MISO is always considering what must be done to maintain service and reliability throughout the footprint. Most recently the RAN initiative is evaluating proactive practices to keep pace in a changing energy landscape, namely an aging generation fleet and increased renewable generation penetration. Through this RAN effort, MISO will study the potential implementation of a seasonal capacity construct as opposed to the current annual planning year. This is in the early stages and not much is known yet about what a potential seasonal construct would look like, let alone whether it would be implemented. For this reason, IPL has modeled the Planning Resource Auction ("PRA") as it currently exists but will continue to follow the issue through the MISO stakeholder process.

5 https://cdn.misoenergy.org/2019%20LOLE%20Study%20Report285051.pdf.

2.2 Fuel Procurement

170 IAC 4-7-4(20)

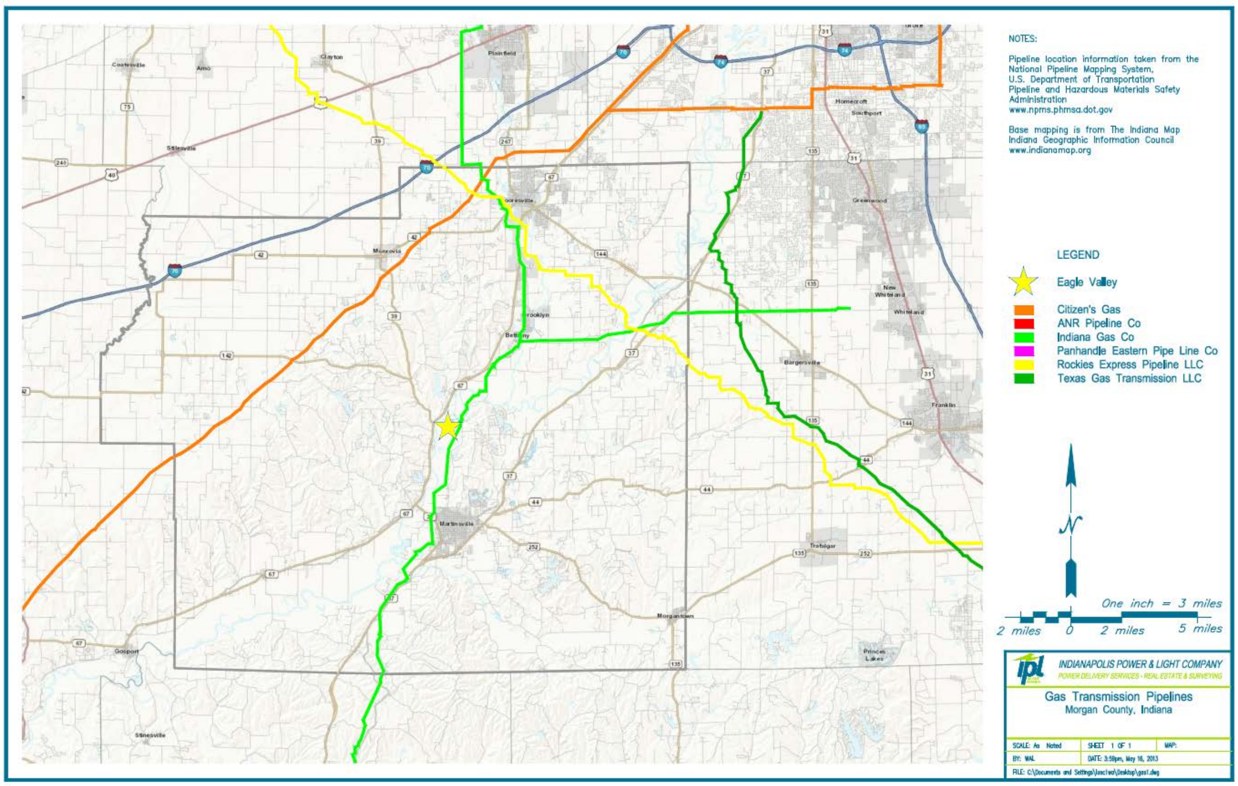
IPL procures and manages a reliable supply of fuel for its generating units at the lowest cost reasonably possible, consistent with maintaining low busbar cost and compliance with all environmental requirements and/or guidelines. Busbar costs reflect those costs needed to produce a kilowatt of energy at the production facility. They do not include transmission or substation expenses.

IPL seeks competitive prices for coal using competitive bidding for both long-term contracts and spot purchases. Long term contracts provide price and supply certainty for IPL customers. Spot purchases are made for three reasons: (1) to meet needs of short term position due to stronger than forecast burns; (2) to test quality of coal and reliability of the producer; (3) to take advantage of occasional low market price coal. IPL considers all material factors, including, but not limited to; (a) availability of supply from qualified suppliers, (b) current inventory levels, (c) diversity of suppliers and transportation options, (d) forecast of fuel usage, (e) market conditions and other factors affecting price and availability, and (f) existing and anticipated environmental standards. To help manage market variability from year-to-year, IPL uses a combination of multi-year contracts with staggered expiration dates to limit the extent of IPL's coal position open to the market in any given year. Many of these multi-year contracts contain some level of volumetric variability as an additional tool to address market variability. IPL prepares long-term projections of fuel purchased, annual inventory levels, quality, and delivered cost for each plant.

For the coal-fired units, IPL maintains coal inventory at levels sufficient to ensure service reliability, to provide flexibility in responding to known and anticipated changes in conditions, and to avoid operational risks due to low inventories. Inventory target ranges are established based upon forecasted usage, deliverability and quality of the required fuel to each unit, the position of the unit in the dispatch order, risk of market supply-demand imbalance, and the ability to conduct quick market transactions. The general level of inventory throughout the year is adjusted to meet anticipated conditions (i.e., summer/winter peak load, transportation outages, unit outages, fuel unloading system outages, etc.).

Natural gas ("NG") is currently purchased on a daily basis as required based on availability and pricing from several suppliers for its NG-fired peaking units at Harding Street and Georgetown. The Eagle Valley CCGT dispatches as a baseload unit so IPL uses a combination of baseload hedges that may include fixed price, index, and daily purchases to supply natural gas to the station. IPL maintains firm pipeline transportation contracts which provide access to Texas Gas Transmission ("TGT") supply zones to supply the Eagle Valley CCGT and Harding Street. The TGT contracts allow IPL scheduling flexibility to draw or hold limited quantity of natural gas which is used for unexpected unit starts & stops to mitigate fuel availability risks. The lateral gas line that serves the Eagle Valley CCGT also has a connection to the Rockies Express pipeline ("REX"). Having a connection with two major supply pipelines allows IPL the ability to balance these two sources for pricing advantages as well as supply certainty. Figure 2.3 is a map of gas transmission around the IPL Eagle Valley CCGT. Since the Georgetown and Harding Street units are used for peaking needs only, firm transportation contracts are not cost-effective. IPL contracts with Citizens Gas for firm redelivery and balancing services to the generating units located at the Harding Street and Georgetown plants, and with Vectren for firm redelivery to the Eagle Valley CCGT.

Figure 2.3 | Gas Transmission Map



2.3 Transmission Planning

170 IAC 4-7-6(b)(3)(B) 170 IAC 4-7-6(b)(4)(A) 170 IAC 4-7-6(b)(4)(B)

2.3.1 Transmission System Overview

IPL provides electric power to the City of Indianapolis and portions of the surrounding counties as a member of MISO. The IPL transmission system consists of approximately 458 circuit miles of lines at 345,000 volts ("345 kV), 408 circuit miles of line at 138,000 volts ("138 kV"), and associated substations.

The IPL transmission system includes 345 kV and 138 kV voltage levels. The 345 kV system consists of a 345 kV loop around the City of Indianapolis and 345 kV transmission lines connecting the IPL service territory to the Petersburg power plant in southwest Indiana. At Petersburg, IPL has 345 kV interconnections with Indiana Michigan Power Company ("AEP"), which ties to the PJM footprint and Duke Energy Indiana ("DEI"), and 138 kV interconnections with DEI, Hoosier Energy Rural Electric Cooperative, Inc. ("HE"), and Vectren Corporation ("Vectren") within the MISO footprint. In the Indianapolis area, IPL has 345 kV interconnections with AEP and DEI and 138 kV interconnections with DEI and HE. Autotransformers connect the 345 kV network to the underlying IPL 138 kV network transmission system which principally serves IPL load.

IPL's electric transmission facilities are designed to provide safe, reliable, and reasonable least cost service to IPL customers. As part of this transmission system assessment process, IPL participates in and reviews the findings of assessments of transmission system performance by regional entities including MISO and ReliabilityFirst ("RF") as it applies to the IPL transmission system. In addition to the summer peak demand period which is the most critical for IPL, assessments are performed for a range of demand levels including winter seasonal and other off-peak periods. For each of these conditions, sensitivity cases may be included in the assessment.

2.3.2 Transmission Planning Process

170 IAC 4-7-4(27)

As a NERC registered Transmission Planner ("TP"), IPL performs an annual transmission reliability assessment to ensure that the NERC performance requirements are met. Additionally, IPL participates in assessments of transmission system performance performed by MISO and RF.

As a member of MISO, IPL actively participates in the MISO Transmission Expansion Plan ("MTEP") process with MISO functioning as the NERC registered Planning Coordinator ("PC"). MISO annually performs MTEP studies to facilitate a reliable and economic transmission planning process. The IPL assessment and MTEP study process includes identification of transmission issues, optional proposals and selects efficient solutions. MISO through either the MTEP or other study processes may additionally propose transmission system projects or other upgrades that are not reliability based but are economically based to relieve congestion. For potential economic projects, MISO assesses costs and benefits to ensure that costs allocated are commensurate with benefits received. Factors in the cost/benefits analysis include: the value of congestion, fuel savings, reductions in operating reserve needs, system planning reserve margins, and transmission line losses of a proposed transmission project or portfolio. Through the MTEP, MISO ensures that transmission is developed system-wide through one uniform planning process that coordinates system needs in order to minimize costs. Generator interconnection requests (additions or material modifications) to the IPL system would be coordinated and studied through the MISO Generation Interconnection Process. Generator retirements would be studied through the MISO Attachment Y process. IPL actively participates in these MISO processes to ensure that the transmission system meets the performance requirements.

The MTEP analysis may be found on the MISO website at URL:

https://www.misoenergy.org/planning/planning/mtep-2018-/

ReliabilityFirst also performs seasonal, near-term, and long-term assessments of transmission system performance conditions based on information from each transmission planner including both MISO and IPL. The transmission system seasonal assessment summarizes the projected performance of the bulk transmission system within ReliabilityFirst's footprint for the upcoming summer peak season and is based upon the studies conducted by ReliabilityFirst staff, MISO, PJM, and the Eastern Interconnection Reliability Assessment Group ("ERAG"). As an entity within the reliability region of ReliabilityFirst, IPL actively participates and reviews the studies and study processes of the assessments.

These assessments may be found on the RF website at URL:
https://rfirst.org/ProgramAreas/RAPA/

IPL seeks to upgrade on a regular basis its ability to model the transmission system and to more accurately forecast its performance. This includes review of available computer software, data collection techniques, equipment capabilities and parameters, and developments in industry and academia. It also includes information sharing with neighboring transmission owners and regional transmission organizations.

Based on its own individual efforts, as well as in concert with others, IPL constantly works to ensure that its transmission system will continue to reliably, safely, efficiently, and economically meet the needs of its customers.

IPL's FERC Form 715 was submitted by MISO to FERC. The FERC 715 was based on MTEP 18 studies which contain the most recent power flow study available to IPL including interconnections. In MTEP 18, MISO conducted studies using models for 2020 Spring Light Load, 2020 Summer Peak, 2023 Spring Light Load, 2023 Summer Shoulder, 2023 Summer Peak, and 2028 Summer Peak. MTEP 19 studies are being finalized.

Finally, IPL and MISO utilize the latest internal customer load forecast, in conjunction with current and future system configurations, generator dispatches, and system transactions (as necessary), as a basis for the afore mentioned system planning and reliability studies.

2.3.3 Transmission Planning Criteria

170 IAC 4-7-4(27)

The IPL transmission system is planned to meet the performance requirements based on system-specific transmission planning criteria, NERC reliability standards, distribution planning requirements and other considerations including but not limited to: load growth, equipment retirement, decrease in the likelihood of major system events and disturbances, equipment failure or expectation of imminent failure.

Changes or enhancements to transmission facilities are considered when the transmission planning criteria are not expected to be met and when the issue cannot feasibly be alleviated by sound operating practices. Any recommendations to either modify transmission facilities or adopt certain operating practices must adhere to good engineering practice.

A summary of IPL transmission planning criteria follows. IPL transmission planning criteria are periodically reviewed and revised.

- Limit transmission facility voltages under normal operating conditions to within 5% of nominal voltage, under single contingency outages to 5% below nominal voltage, and under multiple contingency outages to 10% below nominal voltage. In addition to the above limits, generator plant voltages may also be limited by associated auxiliary system limitations that result in narrower voltage limits.
- Limit thermal loading of transmission facilities under normal operating conditions to within normal limits and under contingency conditions to within emergency limits. New and upgraded transmission facilities can be proposed at 95% of the facility normal rating.
- Maintain stability limits including critical switching times to within acceptable limits for generators, conductors, terminal equipment, loads, and protection equipment for all credible contingencies, including three-phase faults, phase-to-ground faults, and the effect of slow fault clearing associated with undesired relay operation or failure of a circuit breaker to open.
- Install and maintain facilities such that three-phase, phase-to-phase, and phase-to-ground fault currents are within equipment withstand and interruption rating limits established by the equipment manufacturer.
- Install and maintain protective relay, control, metering, insulation, and lightning protection equipment to provide for safe, coordinated, reliable, and efficient operation of transmission facilities.
- Install and maintain transmission facilities as per all applicable IURC rules and regulations, American National Standards Institute ("ANSI")/Institute of Electrical and Electronics Engineers

("IEEE") standards, National Electrical Safety Code, IPL electric service and meter guidelines, and all other applicable local, state, and federal laws and codes. Guidelines of the National Electric Code may also be incorporated.

- The analysis of any project or transaction involving transmission facilities consists of an analysis of alternatives and may include, but is not limited to, the following:
- Initial facility costs and other lifetime costs such as maintenance costs, replacement cost, aesthetics, and reliability.
- Consideration of transmission losses.
- Assessment of transmission right-of-way requirements, safety issues, and other potential liabilities.
- Engineering economic analysis, cost benefit and risk analysis.
- Plan transmission facilities such that generating capacity is not unduly limited or restricted.
- Plan, build, and operate transmission facilities to permit the import of power during generation and transmission outage and contingency conditions. Provide adequate import capability to the IPL 138 kV system in central Indiana assuming the outage of the largest base load unit connected to the IPL 138 kV system.
- Maintain adequate power transfer limits within the criteria specified herein.
- Provide adequate dynamic reactive capacity to support transmission voltages under contingency outage or other abnormal operating conditions.
- Minimize and/or coordinate reactive power measured in Megavolt Amperes Reactive ("MVAR") exchange between IPL and interconnected systems.
- Generator reactive power output shall be capable of, but not limited to, 95% lag (injecting MVAR) and 95% lead (absorbing MVAR) at the point of interconnection to the transmission system.
- Design transmission substation switching and protection facilities such that the operation of substation switching facilities involved with the outage or restoration of a transmission line emanating from the substation does not also require the switched outage of a second transmission line terminated at the substation. This design criterion does not include breaker failure contingencies.
- Design 345 kV transmission substation facilities connecting to generating stations such that maintenance and outage of facilities associated with the generation do not cause an outage of any other transmission facilities connected to the substation. Substation configurations needed to accomplish this objective and meet safety procedures are a breaker and a half scheme, ring bus or equivalent.

- Avoid excessive loss of distribution transformer capacity resulting from a double contingency transmission facility outage.
- Coordinate planning studies and analyses with customers to provide reliable service as well as adequate voltage and delivery service capacity for known load additions.
- Consider long-term future system benefits and risks in transmission facility planning studies.
- Maintain the ability to produce a restoration plan as required by NERC standards in which the use of Blackstart Resources is required to restore the shutdown area of the Bulk Electric System to service.

IPL transmission facilities are also planned and coordinated with the following reliability criteria.

The reliability standards of NERC including the Transmission System Planning Performance Requirements ("TPL") standards, Modeling Data Analysis ("MOD") standards, and Facility Ratings ("FAC") standards. The NERC reliability standards may be found on the NERC website at http://www.nerc.com .

The regional reliability standards of the reliability entity ReliabilityFirst. The RF reliability standards may be found on the RF website at http://www.rfirst.org. IPL is in the RF region.

The IPL Transmission Planning Criteria can be found on the MISO website at https://www.misoenergy.org/planning/transmission-planning/#nt=%2Freport-study-analysistype%3ATO%20Planning%20Criteria&t=10&p=0&s=&sd=asc

IPL complies with NERC TPL-001-4 Planning Events (Contingencies). The transmission system is assessed to meet the performance requirements for System performance of the Bulk Electric System under each Category:

- (Category P0) Under normal (no contingency) conditions.
- (Category P1) For the loss of the one of the following elements: Generator, transmission circuit, transformer, shunt, or single pole of a DC line.
- (Category P2) System performance of the Bulk Electric System for the loss of the one of the following elements: Opening of a line section w/o a fault, bus section fault, or internal breaker fault.
- (Category P3) For loss of multiple elements: Generator and a generator, transmission circuit, transformer, shunt, or single pole of a DC line.

- (Category P4) Following the loss of multiple Bulk Electric System elements caused by a stuck breaker attempting to clear a fault on a generator, transmission circuit, transformer, shunt or bus section.
- (Category P5) Following the loss of multiple Bulk Electric System elements due to a delayed fault clearing due to the failure of a non-redundant relay protecting the faulted element to operate as designed, for one of the following generator, transmission circuit, transformer, shunt or bus section.
- (Category P6) For loss of multiple elements: Transmission circuit, transformer, shunt, or single pole of a DC line.
- (Category P7) For loss of multiple elements for circuits on common structure or loss of a bipolar DC line.

2.3.4 Transmission System Performance Assessment

Individually and combined, the transmission performance assessments performed by IPL, MISO, and RF, demonstrate that IPL meets the system performance requirements of NERC summarized below. From these transmission performance assessments, the IPL transmission system is expected to perform reliably and with continuity over the long term to meet the needs of its customers and the demands placed upon it.

Summary of Performance

- IPL transmission performance analysis using dynamic simulations for stability as evaluated under the NERC Transmission System Planning Performance Requirements (“TPL”) reliability standards shows no evidence of system or generator instability.
- IPL transmission performance analysis as evaluated under the NERC TPL reliability standards shows a few localized thermal violations appearing on IPL lines and transformers resulting primarily from multiple element outages of internal IPL transmission facilities.
- IPL transmission performance analysis as evaluated under the NERC TPL reliability standards shows transmission voltages in the expected range on IPL facilities.
- IPL transmission performance analysis as evaluated under the NERC TPL reliability standards shows expected loss of demand that is planned, controlled, small, and localized.
- IPL transmission performance analysis as evaluated under the NERC TPL reliability standards shows no evidence of curtailed firm transfers.
- IPL transmission performance analysis as evaluated under the NERC TPL reliability standards shows no evidence of area-wide cascading or voltage collapse.

- Applicable operating and mitigation procedures, in conjunction with planned major transmission facility additions and modifications, result in transmission system performance which meets the requirements of the NERC TPL reliability standards.

At the present time there is no measure of system wide reliability that covers the reliability of the entire system that includes transmission, distribution, and generation.

2.3.5 Coordinating Transmission and Resource Planning

During the evaluation of future resource portfolios, it is important that transmission system limitations are evaluated to ensure reliability. One process used to evaluate the transmission system is a power transfer study to determine the import capability into the IPL load pocket. The IPL load pocket is the Indianapolis area load that is supplied by the highly networked IPL 138 kV transmission system that is supplied by external and internal generation. External generation is primarily supplied by seven 345 kV transmission lines connected to a 345 kV loop around load pocket. The 345 kV transmission loop design is analogous to Interstate 465 around Indianapolis. The 345 kV loop connects to the 138 kV system through 345-138 kV autotransformers. The 345-138 kV autotransformers can be analogously thought of as off-ramps on the interstate. Internal generation is interconnected directly to the 138 kV transmission system and is currently located at the three IPL generation plants: Harding Street, Eagle Valley, and Georgetown.

If future resource plans remove generation that is interconnected directly to the 138 kV transmission system, assuming all other parameters remain consistent, more power must be supplied by external generation and transferred to serve the IPL load pocket. A transfer study determines transmission system limitations for the applicable reliability criteria. If the transfer capability is insufficient for a future resource plan, additional transmission upgrades would be needed to meet the reliability criteria. Additionally, the current internal generation provides other ancillary services like reactive power and voltage control, short circuit strength, frequency response and Blackstart capability. Specific analyses will determine the need for any additional upgrades or modification to the transmission system which may be needed to provide these services.

The import capability into the IPL 138 kV system for different NERC contingency categories include a single element failure or breaker failure ranges from 2,233 to 2,934MW. The limit based on a double element failure ranges from 1,415-2,005 MW. Figure 2.4 depicts detailed information about these contingencies.

Figure 2.4 | Import Capability Summary

NERC Category	Limiting Element	Import Capability (MW)	Contingency Description
Single Element (P1)			
2022	Guion North XFMR	2233	Guion South 345-138 kV XFMR
2025	Stout Auto XFMR	2934	Rockville to Thompson 345 kV line
Breaker Failure			
2022	Guion North XFMR	2233	345 kV Breaker #20 at Guion
2025	Future Guion XFMR	2556	Guion N & S 345-138 kV XFMR
Double Element (P6)			
2022	Guion North XFMR	1415	Guion South 345-138 kV XFMR &Whitestown to Hortonville 345 kV line
2025	Hanna East XFMR	2005	Hanna to Stout & Hanna to Sunnyside 345 kV lines
* Import capability can vary based on many factors			

Section 3: Distribution Planning

3.1 IPL's Distribution System Overview

The distribution system consists of 4,961 circuit miles of underground primary and secondary cables and 6,110 circuit miles of overhead primary and secondary wire. Underground street lighting facilities include 773 circuit miles of underground cable. Also included in the system are 138 substations. Depending on the voltage levels at the substation, some substations may be considered both a bulk power substation and a distribution substation. There are 73 bulk power substations and 117 distribution substations; 52 substations are considered both bulk power and distribution substations. IPL uses a Secondary Network System to serve the City of Indianapolis Central Business District, sometimes also referred to as the "Mile Square." A unique feature of the Secondary Network System is that the loss of a single component, such as a primary feeder or a network transformer, typically will not result in any customer losing power.

IPL is incrementally investing in smart grid assets. Standard equipment specifications include smart grid enabled communication devices, such as relays, reclosers, load tap changers ("LTCs"), and capacitor controls. In 2016, IPL deployed a Distributed Temperature Sensing ("DTS") pilot project to monitor temperature in the duct lines and manholes of the downtown network system. The system uses fiber optic cable to monitor temperatures in one-meter increments. As of 2016, IPL has installed approximately 36,000ft of fiber optic cable for the DTS project. In addition to the DTS project, in 2018, IPL deployed a Distributed Acoustic Sensing pilot project ("DAS"). The DAS system essentially turns the fiber optic cable into a linear acoustical sensor. The system allows us to determine the location of primary cable faults and potential damage to our infrastructure from other entities. As part of the proposed IPL TDISC Plan, see Section 3.3, starting in 2020, IPL would install over 100,000ft of fiber optic cable to complete both the DAS and DTS systems.

3.2 Distribution System Planning

170 IAC 4-7-4(18)

IPL's Electric Distribution System Plans are based on various criteria and parameters that are used to determine expansion and replacement requirements. The criteria and parameters include: consideration of load growth, equipment load relief, timely equipment replacement to optimize performance, effects of major system events, reliability improvements, National Electric Safety Code ("NESC") requirements, and industry guides and design standards.

Distribution construction projects are based on the results of IPL's small area load studies. Grid area data, such as historical data, land use statistics, and demographic customer data, provide the basis for long-range demand projections. These projections are modified for the short-term based on known customer additions, DG projects, and recent historical substation load growth since the grid area data cannot predict short-term deviations from long-term statistical trends. Distribution substations additions or improvements are planned when projected area loads cannot be served from existing substations or if existing substation facilities reach their design limits. In parallel, circuit construction is planned to utilize newly installed substation capacity, to provide relief to circuits projected to exceed design capacity, or to improve reliability or operational performance.

Industrial substation expansion provides capacity for known industrial load additions and relieves existing or anticipated overloaded facilities. Several customers, either by internal policy or government regulations, may be required to maintain 100% emergency capacity, and the Company's additional investment is recovered through excess facility agreements. IPL's policy is to provide such service to certain public service customers, such as hospitals and communications facilities, provided the customer meets specific engineering design criteria.

3.3 IPL's Pending Transmission Distribution Storage System Improvement Charge ("TDSIC") Plan

On July 24, 2019, IPL filed its TDSIC Plan with the IURC. IPL's TDSIC Plan proposes seven years of defined investment, totaling $1.2 billion, to replace, rebuild, upgrade, redesign and modernize a wide range of IPL's aging T&D system assets in two thematic areas: *Age and Condition*, and *Deliverability*.

The *Age and Condition* (83.3% of the estimated Plan cost) category addresses the many risks posed by aging assets. The category includes the replacement and rebuilding of substations and overhead circuits, the rehabilitation and repair of underground residential circuits, and rebuilding portions of the central business district. The *Deliverability* (16.7% of the estimated Plan cost) category deploys new technologies for advanced distribution management, adds new substation equipment to meet growth-driven capacity requirements, and creates system and operating efficiencies through automation, control functions, and other advanced infrastructure.

Both categories support IPL's ability to maintain and operate the grid in a safe, reliable, and efficient manner. Many of the modernizing improvements are focused on giving IPL's operators and engineers more information and control over the grid for purposes of delivering a better, more efficient energy experience. Other Projects target improvement in overall levels of reliability and integrity.

For more information on IPL's pending TDSIC Plan, see IURC Cause No. 45264. As part of IPL's proposed TDSIC Plan, certain projects will have impacts on the IPL Distribution System. These projects include 4 kV Conversion project, Advanced Metering Infrastructure project and Distribution Automation project. These projects, if approved by the Commission, contribute to a hardened and resilient grid which can better withstand the impact of weather and is easier to restore when outages inevitably occur.

3.3.1 4 kV Conversion

Included in the IPL TDSIC Plan, a 4.16 kV to 13.2 kV conversion plan is included and consists of the replacement of critical transformers and the conversion of radial circuits where 13.2 kV sources are available to avoid overloads on critical substations. This plan is formulated to avoid the failure of adjacent substations that may lead to a cascading outage event. Any equipment with remaining life that is removed due to conversion is used to provide adequate capacity to the remaining 4.16 kV loads, to provide spare units to cover unforeseen transformer or switchgear failures, or to permit the retirement of equipment which has outlived its useful life and cannot provide reliable service.

3.3.2 Advanced Metering Infrastructure ("AMI")

170 IAC 4-7-4(16)

If approved by the IURC under the IPL TDSIC Plan, IPL will replace approximately 350,000 residential and small commercial single and three phase electric meters over a five-year period beginning in 2020. The planned deployment rate is approximately 5,833 per month. IPL has been using an Automatic Meter Reading ("AMR") system for its energy-only metered customers since 2001 to automatically read meters. Since the AMR system operates well in acquiring daily readings for energy only meters, beginning in 2010, as part of the Smart Energy Project, IPL initiated AMI to capture demand meter interval data which was still being manually read. There have continued to be additional single-phase meter replacements since that time. IPL has 182,162 AMI meters as of October 2019 with remote connect/disconnect capability located in areas of high customer turnover. Over 99% of IPL's meters are automated, which enables customers using the IPL web-portal known as PowerView® to see their energy usage information (with a one-day delay).

AMI benefits include 15-minute interval usage data, avoided truck rolls for service reconnection, better outage prediction through a "last gasp" from meters, remote verification of outage status, remote voltage sensing which supports distribution operations, and residual customer satisfaction from these enhanced services

3.3.3 Distribution Automation

Distribution Automation ("DA"), has enhanced outage restoration with the additional reclosers and advanced relays allowing sections of circuits to be isolated if there is a fault on the system resulting in fewer customers experiencing a service interruption. In addition, quicker service restoration results when operators may remotely back-feed sections of circuits. Circuits are now operated more efficiently with interactive information received from devices with two-way communication equipment. IPL has remote operation capabilities with feeder relays, reclosers, and capacitors.

As part of the pending TDSIC Plan, the Distribution Automation Project adds distribution infrastructure and replaces older control systems with modern control systems that will increase automation, improve distribution infrastructure safety, operation and reliability, facilitate outage management and service restoration; enable voltage control and associated energy conservation; and improve interconnection with distributed resources. If approved, IPL will install 1,200 new distribution line reclosers and a new central control system to further increase system automation; to improve distribution system operation and reliability; to enable voltage management and associated energy conservation; and to facilitate interconnection with distributed energy resources and new loads.

An Advanced Distribution Management System improves reliability with Fault Location, Isolation, and Service Restoration ("FLISR") functionality. The FLISR functionality is expected to eliminate a significant number of customer interruptions per year. It is also expected to reduce the duration of a significant number of interruptions per year to less than 5 minutes.

3.4 Future Distribution System Needs

3.4.1 Distribution Generation

170 IAC 4-7-4(18)

IPL's Smart Grid network enables dispatch personnel to interface with large DG assets in real-time to monitor production and control the interconnecting equipment to protect line personnel when necessary. IPL has successfully connected 96 MW of solar DG since 2011 through its Rate Renewable Energy Production ("REP") program with operating agreements to enable monitoring and control of facilities with nameplate capacities of 500 kW and above. This includes nineteen (19) utility scale sites ranging in size from 500 kW to 10 MW in nameplate alternating current capacity. Attachment 3.2 includes a list and map of the Rate REP facilities. IPL's experience with solar facilities indicates no significant impact to its distribution or transmission system. This is due to many factors including the decision to limit the total capacity per site to 10 MW, connect the facilities at 13.2 kV, and establish the engineering criteria for a maximum of 10 MW connected per substation transformer.

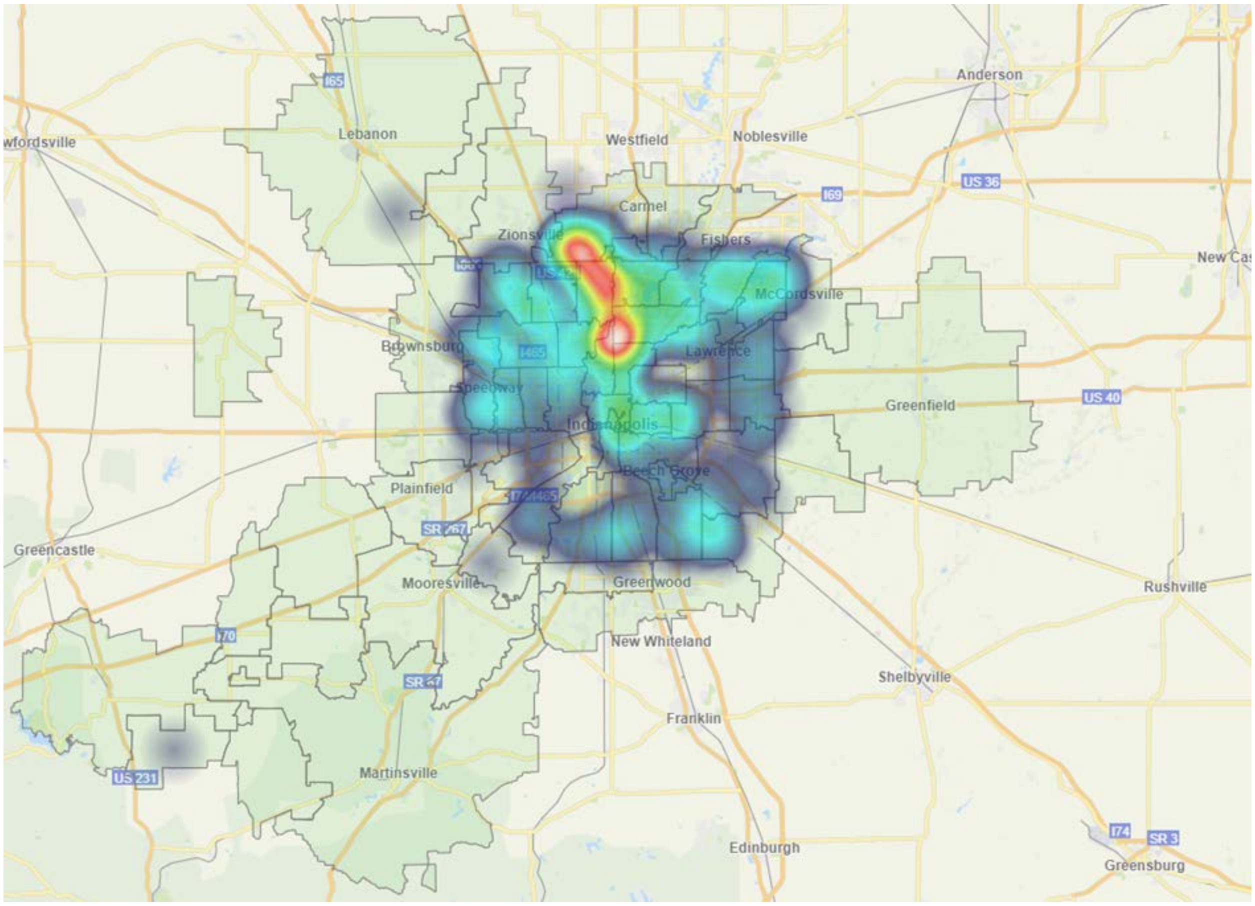
Distribution circuit impacts have been monitored and mitigated through IPL's DG interconnection working group comprised of personnel from engineering, planning, construction, and operations groups. Specifically, remote control capabilities are enabled through reclosers connected to IPL's DA network. Protection settings for the inverter control systems, reclosers, and IPL feeder relays are reviewed by IPL engineers and adapted as needed to avoid "nuisance" tripping that isolates the DG from the IPL grid. IPL monitors the output of the sites over 500 kW in real-time through its dSCADA system. IPL will continue to evaluate the business practices as more DG comes on-line. Section 5 contains more information about existing and "new" solar resources. Smart Grid infrastructure allows IPL to interface with DG resources and gather and monitor output in real time.

As further described in Section 5, IPL has 234 net metered customers as of the end of September 2019. They are smaller facilities than Rate REP and do not provide real time data to IPL dispatchers.

3.4.2 Electric Vehicles

Since the 2016 IRP, IPL has worked to develop a process which utilizes internal and external data to map and locate Electric Vehicle (EV) charging throughout our service territory. See Figure 3.1 below, which shows penetration of EV ownership by zip code. A higher penetration of EV ownership as shown represents a proxy for associated on-premise charging in absolute terms. In other words, the heat map does not reflect the level of demand or energy associated with electric vehicle charging but defines geographic areas where EV adoption is highest. This mapping, which will be updated periodically, is being incorporated into IPL's distribution software for ongoing distribution planning and analysis purposes.

Figure 3.1 | Heat Map of EV Adoption by Zip Codes



As of the summer of 2019, there are approximately 600 plug-in EVs in IPL's service territory, which represents ~0.1% of total passenger vehicles in Marion County (Indianapolis)[6].

As EV penetration grows over time, IPL will continue to leverage internal and external data sources to assess and manage impacts on the distribution system. IPL is working towards mapping individual IPL customers to their transformers in IPL's CYME distribution model. IPL is also mapping BMV lists for hybrid and EV customers to their respective transformers. Awareness of EV charging locations allows engineers to verify existing facility capacity and upgrade requirements. To date these have been limited to customers' service and panel upgrades, but any future transformer replacements will be managed closely by IPL. Understanding grid impacts will help guide development of future customer program

[6] The number of electric vehicles is from internal/external data sources from summer 2019. The total number of registered passenger vehicles is based on registration data from https://www.stats.indiana.edu/topic/vehicles.asp

offerings like time varying rates, managed EV charging, and/or other targeted demand response solutions.

IPL has supported EVs since our electric vehicle ("EV") pilot program as part of the Smart Energy Project initiated in 2012. That initial effort included the deployment of one hundred sixty-two (162) chargers and special EV rates for home, business and public use. EV meters allow IPL to monitor impacts to the distribution grid. These impacts are minimal today but will increase through time as EV penetration grows. Transformer loading analyses are being completed for each site request for an EV meter. The work thus far has not required any transformer replacements.

EV penetration in the Indianapolis area has been slower than anticipated. Section 4 contains more information about impacts of EVs on energy consumption which is incorporated in the EV forecast completed for IPL by the consultant MCR in this IRP.

3.4.3 Future Smart Grid Expectations

IPL recognizes that as more distributed energy resources ("DERs") are added to our system, their role will increase in future transmission, distribution and resource planning efforts. These planning efforts inform each other to ensure alignment in the consideration of DERs across the system. These resources can provide capacity and energy benefits. IPL continues to incorporate additional business and operational practices to maximize benefit.

Section 4: Load Research, Load Forecast, and Forecasting Methodology

170 IAC 4-7-4(11)

IPL forecasts load to be flat with average annual growth of 0.4% over the IRP planning horizon before consideration of any DSM impacts.[7] EIA projected efficiency trends with strong lighting and ventilation intensities in the commercial sector are the key contributor to the stagnant load trend.

4.1 Load Research

170 IAC 4-7-4(13) 170 IAC 4-7-4(16)

IPL conducts load research based on historic customer load shape data by segment. This information is used in Cost of Service studies and rate design efforts. The granular data aligns with load forecasting data, but it is not a direct input to the forecast at this time. See Attachment 4.1 for the Hourly Load Shapes by Rate and Customer Class from the July 2016 to June 2017 Test Year in IPL's Rate Case (Cause No. 45029). IPL anticipates using AMI more fully for load research and load forecasting as an improvement in the next IRP.

Load shape data is maintained by IPL at the rate class/customer class level. The sample for the Small Commercial Class (Rate SS) is stratified using North American Industry Classification System ("NAICS") codes into manufacturing low and high use and non-manufacturing low and high use strata. All load research is developed by IPL.

4.1.1 Energy Only (Non-Demand) Metered Customers

IPL currently maintains a load research sample of 542 load profile meters. The distribution of these meters by rate and class are shown in the following table, Figure 4.1.

Figure 4.1 | Load Research Meters by Rate Class – Energy Only

Rate RS	126	Rate SS	95
Rate RC	102	Rate SH	68
Rate RH	151		
Total Residential	379	Total Small C&I	163

[7] IPL-sponsored DSM has been removed from the load forecast.

4.1.2 Large Commercial and Industrial Customers

In addition to the Residential and Small Commercial & Industrial meters outlined above, all Large Commercial & Industrial have 15-minute profile metering. The 15-minute information provides load research and billing increment data for our demand metered customers.

Figure 4.2 shows the load research sample design which is designed based upon a 90% confidence interval plus or minus 10% error. The stratification criteria are shown for the following rates:

RS – Residential General Service

RC – Residential General Service with electric water heating

RH – Residential General Service with electric heat

SS – Small Commercial & Industrial Secondary Service (Small)

SH – Small Commercial & Industrial Secondary Service (Electric Space Conditioning)

Figure 4.2 | Load Research Design

Rate	Number of Strata	Criteria
RS	4	high/low winter and high/low summer
RC	4	high/low winter and high/low summer
RH	5	small/large heat pump houses, small/large resistance houses and apartments
SS	4	survey small/large by manufacturing; non-manufacturing; billing manufacturing/non-manufacturing
SH	4	annual kWh

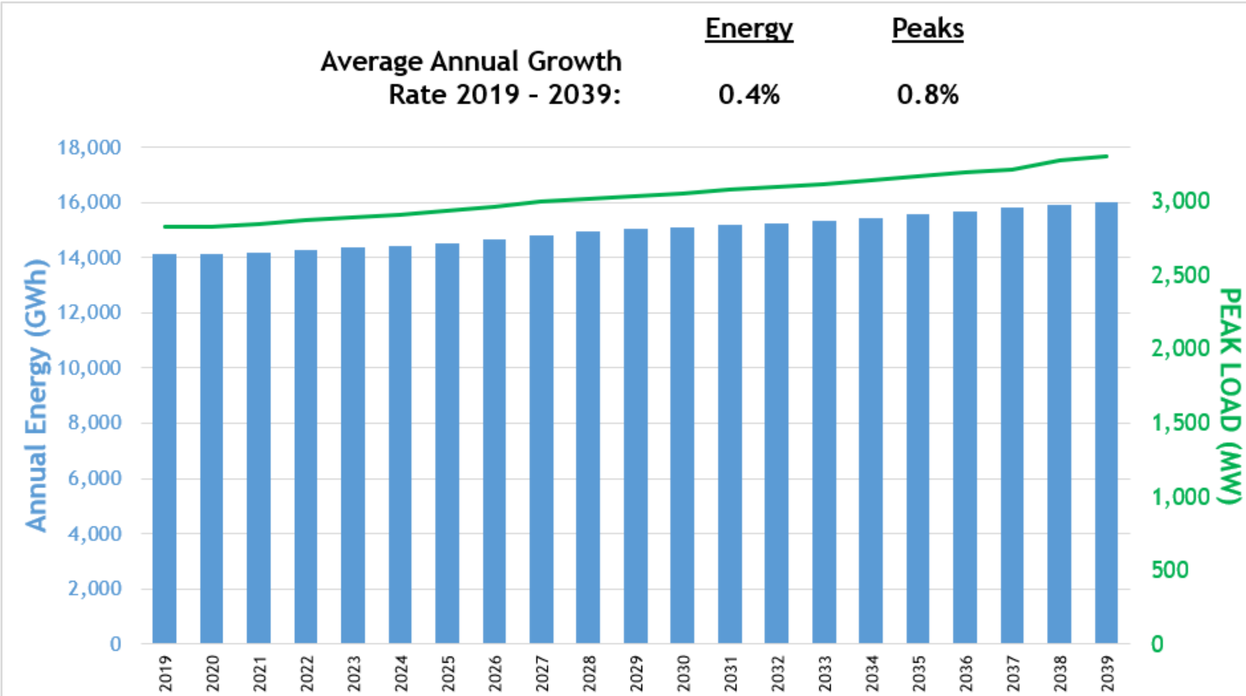
Furthermore, Hourly 8760 data is retained in Excel spreadsheets.

Historical billing data by account for the demand billed customers is maintained on an on-going basis.

4.2 IPL Forecast Overview

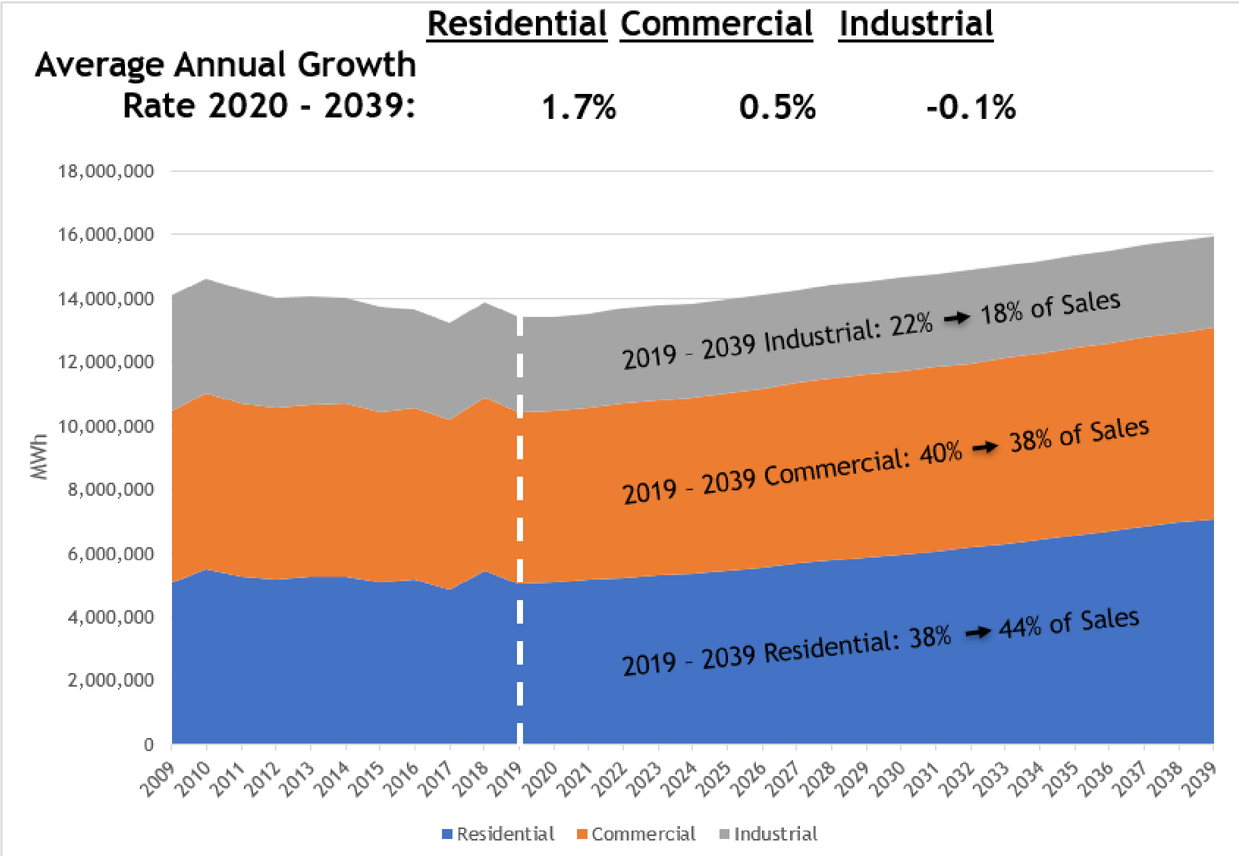
IPL developed a forecast with the average annual growth rate over the study period 2020 – 2039. Figure 4.3 shows the energy and peak forecast.

Figure 4.3 | Energy and Peak Forecast



IPL anticipates stable customer growth in the Residential sector primarily in multifamily units, such as apartments, condos and townhouses. This growth is expected to increase average annual load at a rate of 1.7% over the planning period. Customer growth is expected to be modest in the Commercial sector keeping load relatively flat with an average annual growth of 0.5%. Industrial sector load is anticipated to decline at an average annual rate of -0.1% over the planning period due to a declining manufacturing employment outlook and efficiency trends. Figure 4.4 illustrates the customer sector trends.

Figure 4.4 | IPL Sales by Sector (no losses included)



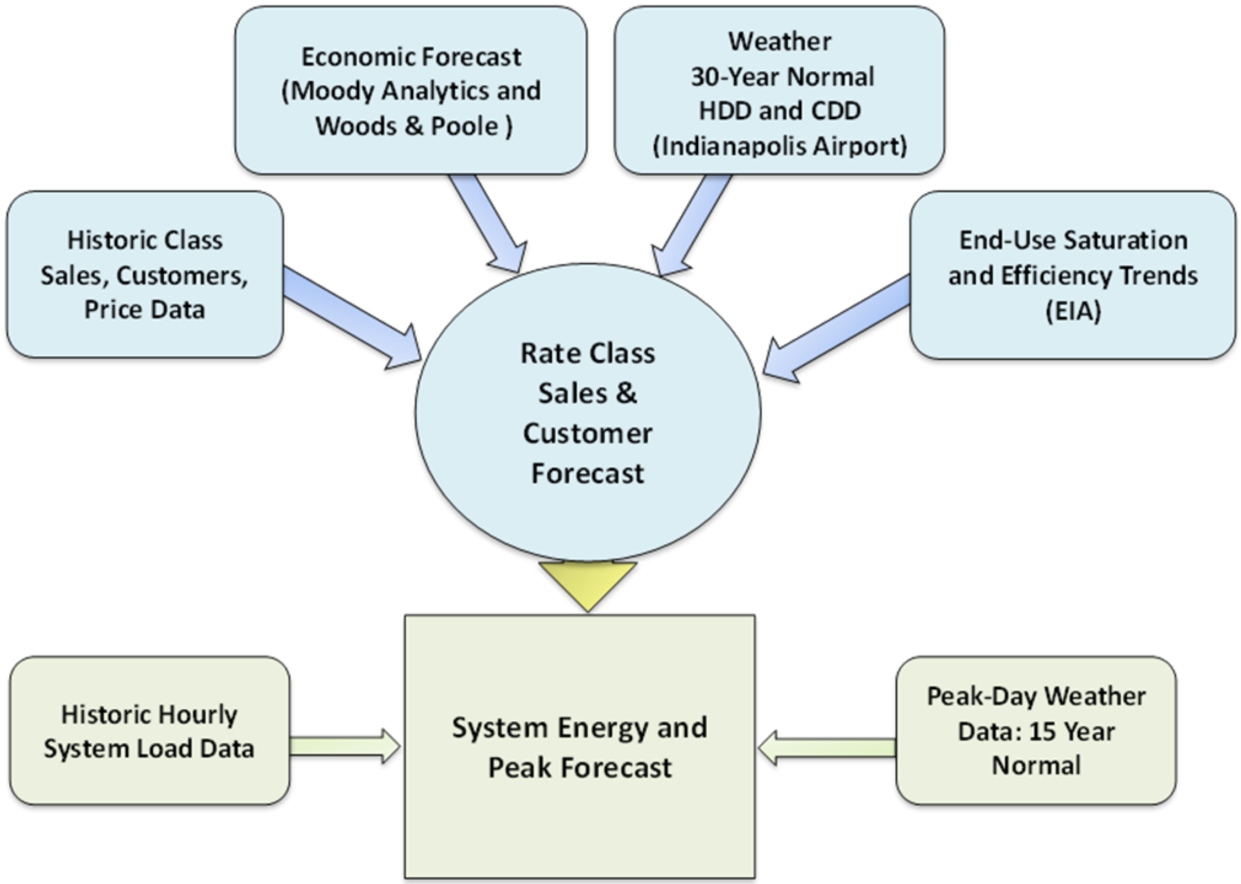
4.3 Forecast Methodology

170 IAC 4-7-4(1) 170 IAC 4-7-4(3) 170 IAC 4-7-4(28) 170 IAC 4-7-5(a)(4) 170 IAC 4-7-5(a)(7) 170 IAC 4-7-5(a)(8) 170 IAC 4-7-6(a)(6)

The load forecast in this IRP was developed by IPL using Itron's Statistically Adjusted End-use ("SAE") load forecasting methodology. Historically, GDP and other economic indicators exhibited strong correlation with electricity sales. As such, load forecasts were heavily reliant on GDP and economic forecasts. However, since 2008 this linkage is less pronounced. Sales have flattened due to efficiency improvements from codes and standards and utility-sponsored DSM while GDP has continued to grow. Itron's SAE methodology addresses this issue by incorporating end use saturations and efficiency trends using EIA data.

Figure 4.5 provides an overview of the workflow of Itron's SAE model that builds up to a System Energy and Peak forecast. The dependent variables are being predicted using estimates of cooling requirements (XCool), heating requirements (XHeat) and other uses (XOther). These three variables are constructed using the weather, economic, utility price, and end use inputs. Thus, all structural and equipment changes, predicted economic impacts, price elasticities and weather assumptions are captured in the resulting forecast.

Figure 4.5 | Forecasting SAE Model Overview of Inputs



IPL forecasts monthly sales and customers for each rate code using the method described above. The rate code level forecasts are aggregated into a system-level forecast where line losses are added based on historic loss factors. This system-level forecast along with the system hourly load history, peak-day weather and end use intensity data drive the peak forecast.

Figure 4.5 illustrates the independent variable inputs that flow into the model. The independent variables with data source descriptions are as follows:

- *End-use appliance saturation and efficiency trends data* - Energy intensities are derived from Energy Information Administration's ("EIA") 2018 Annual Energy Outlook ("AEO") for the East North Central Census Division. The EIA End Use Data is available in Confidential Attachment

4.2a – 4.2g. The residential sector incorporates saturation and efficiency trends for seventeen end-uses. The commercial sector captures end-use intensity projections for ten end-use classifications across ten building types. The EIA doesn't provide saturation and efficiency trends for the industrial sector.

As part of the DSM Market Potential Study that began in 2018, IPL conducted an in-depth end-use analysis of each customer sector in order to gain an accurate representation of the saturations and efficiencies of equipment in the service territory. Results from the analysis informed the EIA intensity base year assumptions used in the Itron models. Future intensities still rely on the EIA forecasts of equipment saturation and efficiencies. For more information regarding end use modeling techniques, see Attachment 4.3.

- *Economic data* – Economic inputs are Moody's Analytics projections from Q4 2018, see Confidential Attachment 4.4a. The high and low forecasts use a combination of different Moody's Q4 2018 economic scenarios and forecast model standard deviations, see Confidential Attachments 4.4b and 4.4c. The high and low load forecasting approach will be described later in this section.

- *Historical class sales and customers* – IPL tracks historical sales and customer data for each discrete rate code which serves is an input into the load forecasting models.

- *IPL price forecast* – Historical prices are derived from billed sales and revenue data. Prices are calculated as a 12-month moving average of the average rate (revenues divided by sales including trackers); prices are expressed in nominal dollars.

- *Weather data* – Historical and normal monthly heating degree days ("HDD") and cooling degree days ("CDD") are derived from National Oceanic and Atmospheric Administration daily temperature data for the Indianapolis Airport. For residential classes, a temperature base of 60 degrees is used in calculating HDD and a temperature base of 65 degrees are used in calculating CDD. For commercial classes, a temperature base of 55 degrees is used in calculating HDD and a temperature base of 60 degrees are used in calculating CDD. Generally, industrial classes are not considered weather sensitive and only receive a small if any weather adjustment. The base temperature selection is determined by evaluating the sales/weather relationship and determining the temperature at which heating and cooling loads begin.

For future normal weather assumptions, IPL uses a 20-year weather trend approach to capture the effects of climate change on normal temperatures. Figure 4.6 and Figure 4.7 illustrate this approach. Using this approach, IPL calculated the year-over-year trend in the 20-year rolling average HDDs and CDDs over the past 20 years. HDDs have declined on average by -0.3%; whereas CDDs have increased by 0.6%. These trend percentages are assumed to continue over the period of the analysis. The base year (2019) normal HDDs and CDDs are 20-year averages of 2009 – 2018 HDDs and CDDs.

Figure 4.6 | HDD Weather Trend Approach

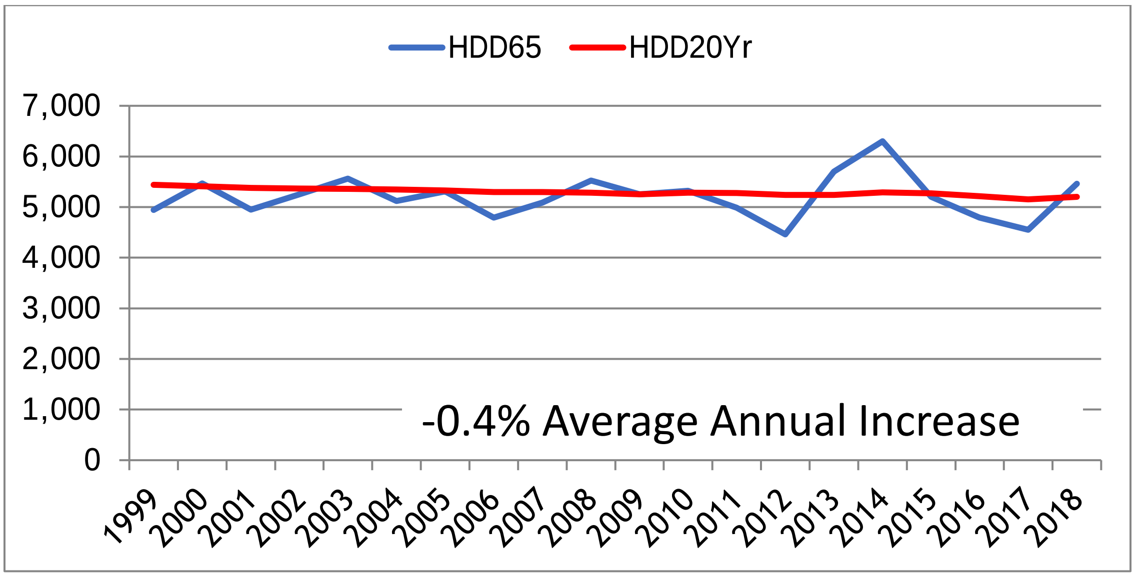
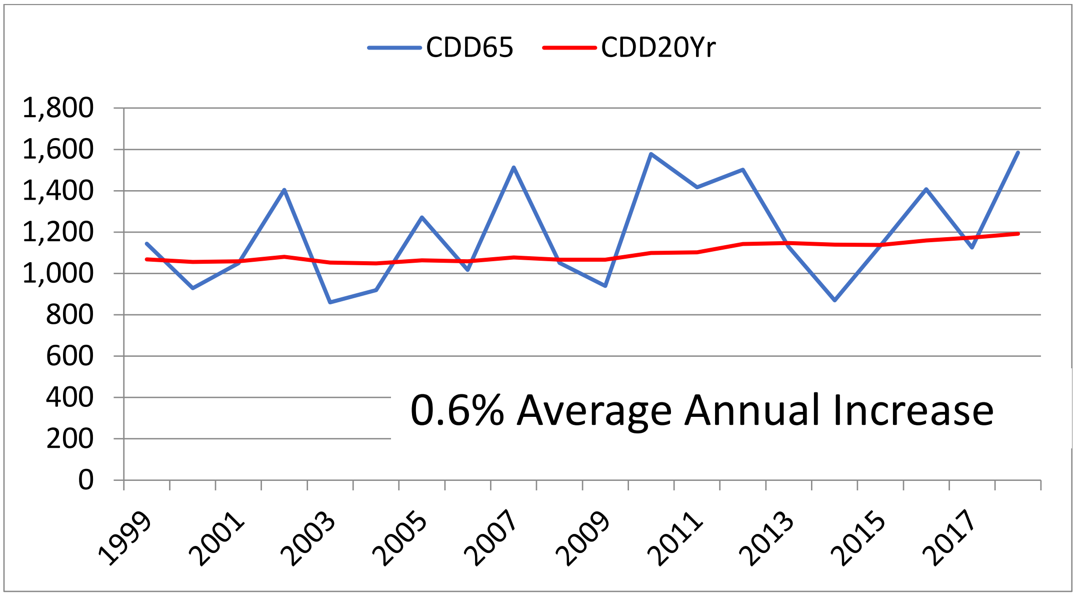


Figure 4.7 | CDD Weather Trend Approach

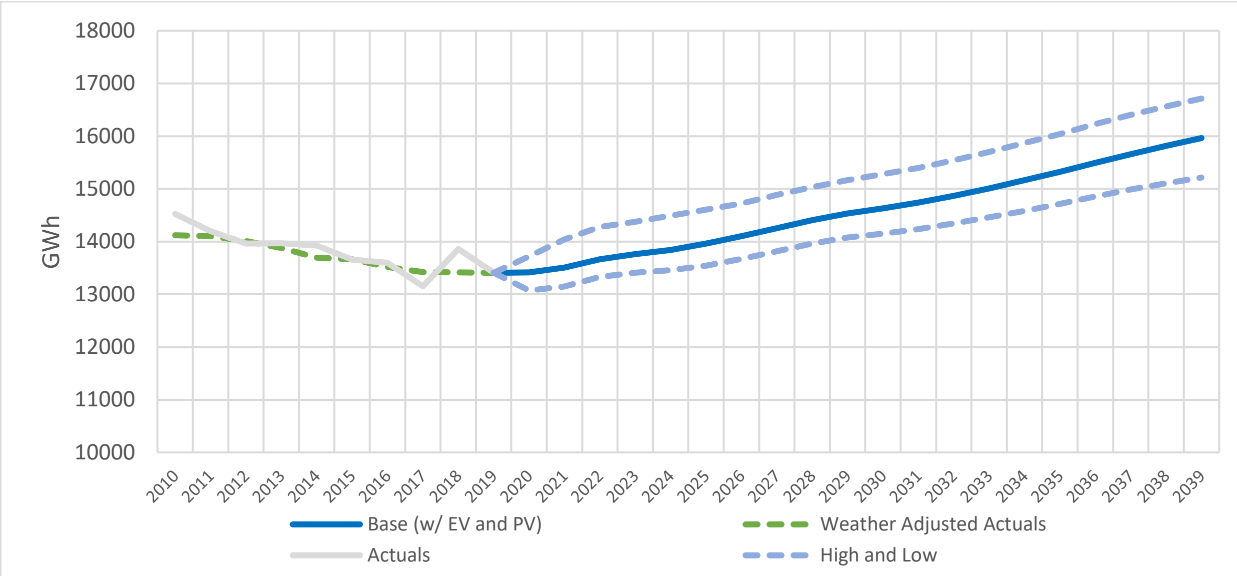


- *IPL-sponsored DSM* was included as an endogenous variable in the sales models. As an input, the models assessed correlation between historic sales and historic DSM estimating a DSM coefficient. For example, if the model estimates a coefficient of 0.5, then the model is saying that 50% of the historic DSM is captured in the historic sales. IPL then adjusts out any planned DSM based on this approach.

  As noted, future IPL DSM was not included in the base, high or low energy and peak forecasts that were used as inputs into the IRP. New DSM bundles were included as part of the process for developing candidate resource portfolios. See Section 8 for more detail on DSM selection for the IRP.

In addition to the base forecast, IPL developed high and low load forecasts for use in certain IRP scenarios. The forecasts were developed using the growth rates from Moody's "Lower Trend" (low forecast) and "Exceptionally Strong Growth" (high forecast) scenarios with one standard deviation from the base forecast mean (as calculated using the Itron models) as the target in 2039. See Confidential Attachments 4.4a-c for Moody's data. The Base, High and Low Load Forecasts assume normal weather. The IPL Base, High and Low Forecasts (Figure 4.8) does not include future DSM. Attachment 4.5 is the 10 Year Forecast and Attachment 4.6 is the 20 Year High, Base and Low Forecast.

Figure 4.8 | IPL Base, High & Low Load Forecast (2020-2039)



4.3.1 Residential Sector

The Residential Sector is comprised of three primary customer types; those with gas heat, electric heat and gas heat with electric water heat. On a percent of customer basis, the residential customer types are disaggregated as follows: 57% gas heat, 7% electric heat and 36% gas heat with electric water heat. While on a percent of sales basis, the residential customer types are disaggregated as follows: 46% gas heat, 8% electric heat and 46% gas heat with electric water heat. The Residential Sector makes up 38% of IPL's total sales.

The key residential forecast economic drivers are Marion County housing starts, Marion County household income and Marion County household size. Over the next 20 years, the number of housing starts are projected to grow at an average annual rate of 2% while household income is projected to grow at an average annual rate of 0.8%. Both will increase customer volume and total usage. Household size is anticipated to decline at a rate of -0.4% which is consistent with the trend in household growth primarily coming in the form of multifamily apartments described in detail below.

Figure 4.9 displays the projected trends in customer count and Figure 4.10 presents average electricity use across the Residential Sector. New customers are projected to increase at an average annual rate of 0.8% while average use is expected to increase at an average annual rate of 0.4%.

Figure 4.9 | Residential Customers

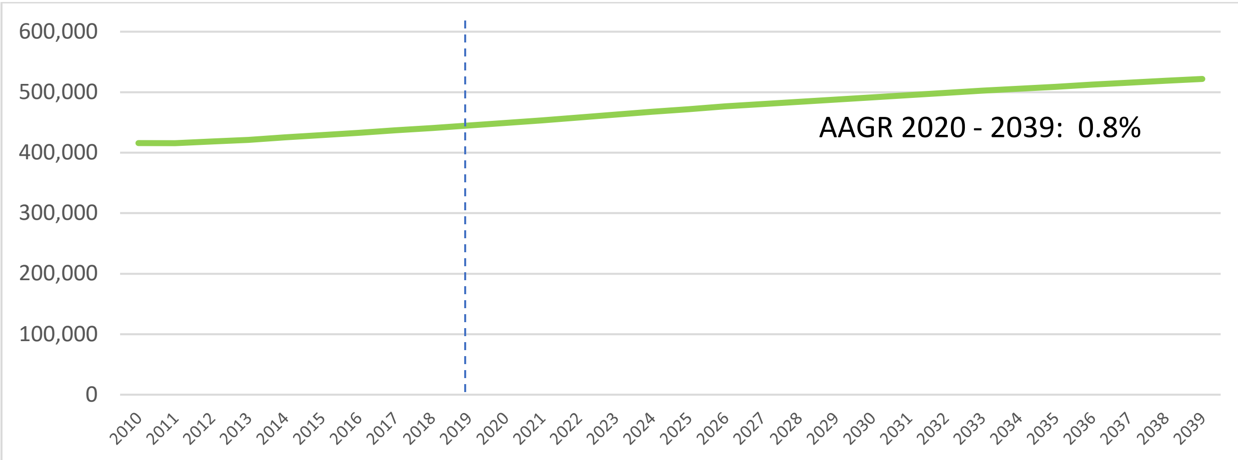
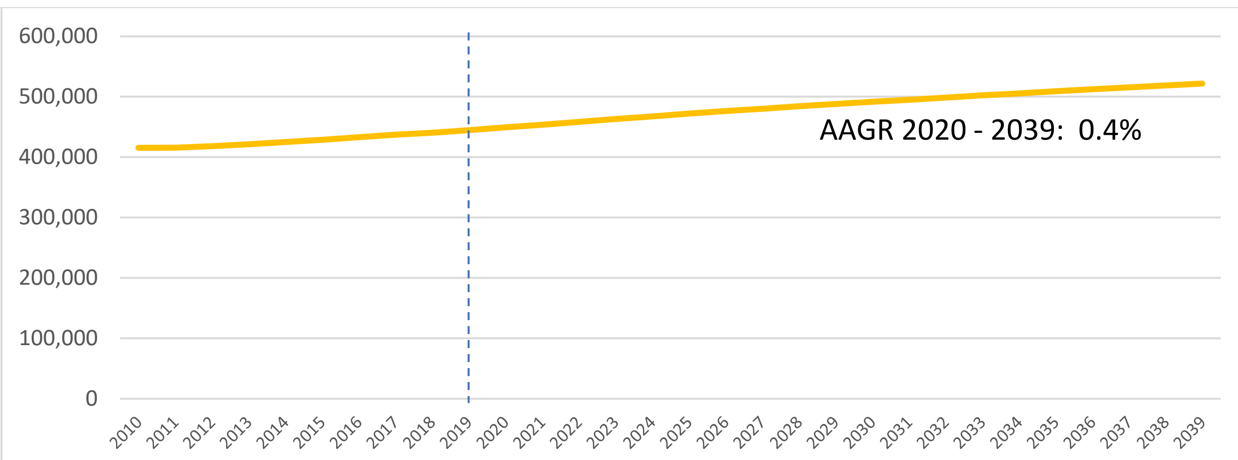


Figure 4.10 | Residential Average Use



Customer growth is expected to come primarily through additional multifamily apartments; a trend that was demonstrated by the Indianapolis Business Journal (IBJ) in Figure 4.11. Between 2007 and 2018, the volume of apartments in downtown Indianapolis has grown by 250%. Apartments are on average smaller in conditioned square footage than a single-family home and therefore require less electricity. This growth is evident from new projects like the conversion of the Coca-Cola Bottling site into the mixed use Bottleworks development.

Figure 4.11 | Indianapolis Apartment Growth[8]

The shift in the Residential sector to a higher percentage of multifamily homes in combination with organic efficiency contributes to the forecasted flat-to-declining sales per customer.

Overall, customer volumetric growth is anticipated to outpace the decline in average electricity use, leading to a sales forecast that is projected to grow at an average annual rate of 1.7%, as shown in Figure 4.12.

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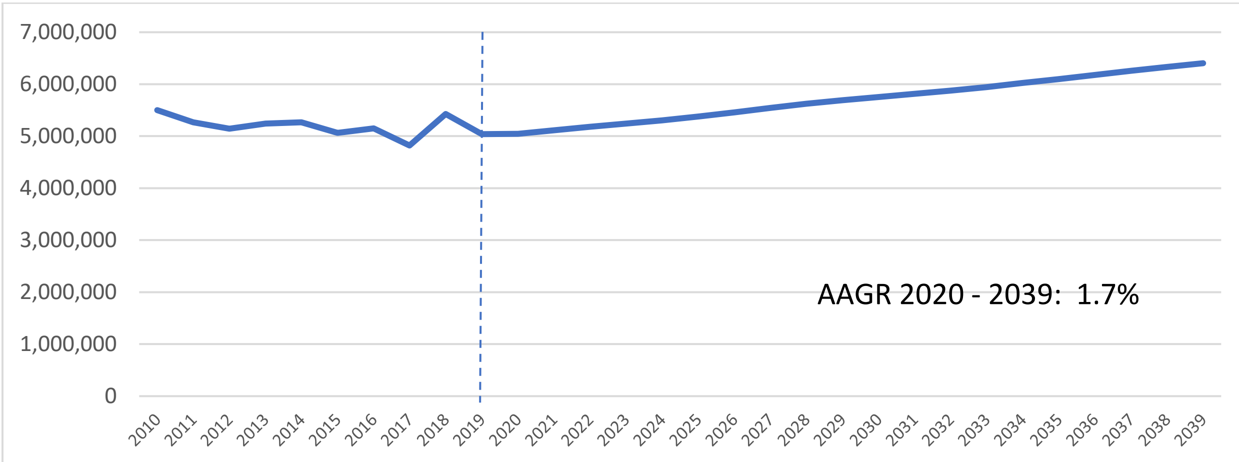
[8] Source: Indianapolis Business Journal

Figure 4.12 | Residential Sales



4.3.2 Commercial Sector

The Commercial sector includes customers with demand of less than 500 kW including small commercial gas and electric heat rates of 75 kW or less. Also included in this sector are larger secondary service demand metered customers between 50 – 500 kW; examples include grocery and box stores. The Commercial sector comprises 40% of total IPL sales. IPL anticipates continued growth in this sector from large commercial projects with tech companies like Infosys, 16 Tech and the city's new Criminal Justice Center.

The key economic drivers to the Commercial forecast are Marion County nonmanufacturing employment and Marion County nonmanufacturing GDP. As mentioned previously, the forecast uses an economic variable that is heavily weighted towards nonmanufacturing employment which is a better predictor of sales – 80% nonmanufacturing employment / 20% nonmanufacturing GDP. Over the 20-year IRP period, nonmanufacturing employment is expected to grow at an average annual rate of 0.8% and nonmanufacturing GDP at a rate of 1.9%. The combined variable used in the forecast had an average annual growth rate of 1.04%. Commercial sales growth is kept modest in the long term due to more aggressive lighting and ventilation efficiencies that the EIA is now including in their outlook.

Figure 4.13 and Figure 4.14 display the projected customer count and average electricity use for the Commercial sector. The number of new customers is projected to grow at an average annual rate of 0.42%; while the average use per customer is exhibits only modest growth at an average annual rate of 0.13%.

Figure 4.13 | Commercial Customers

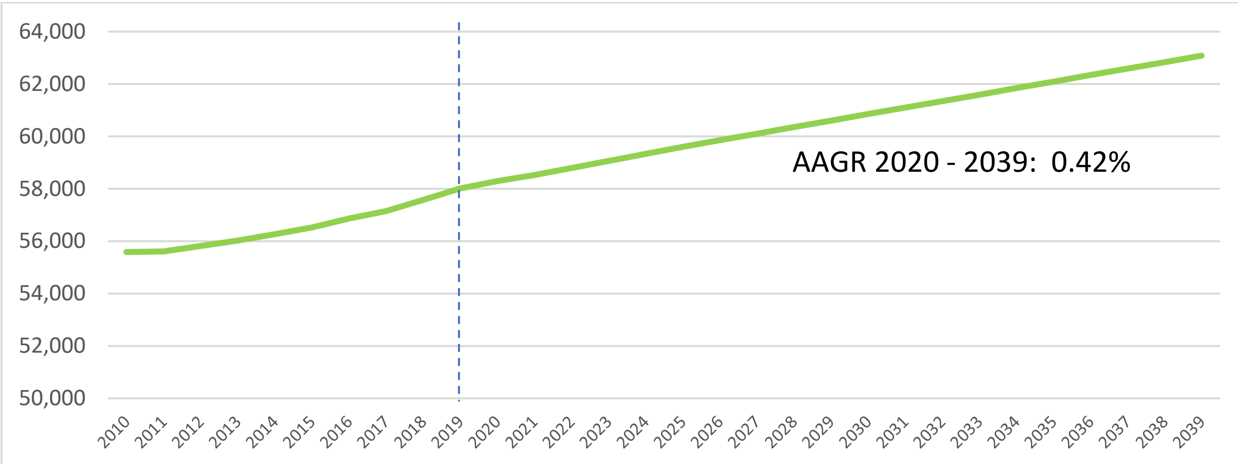
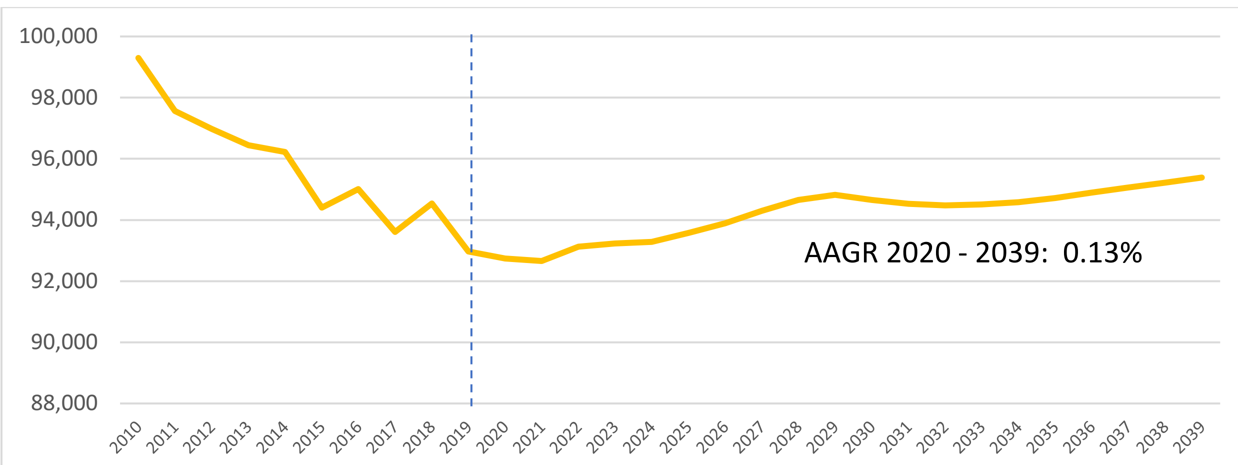
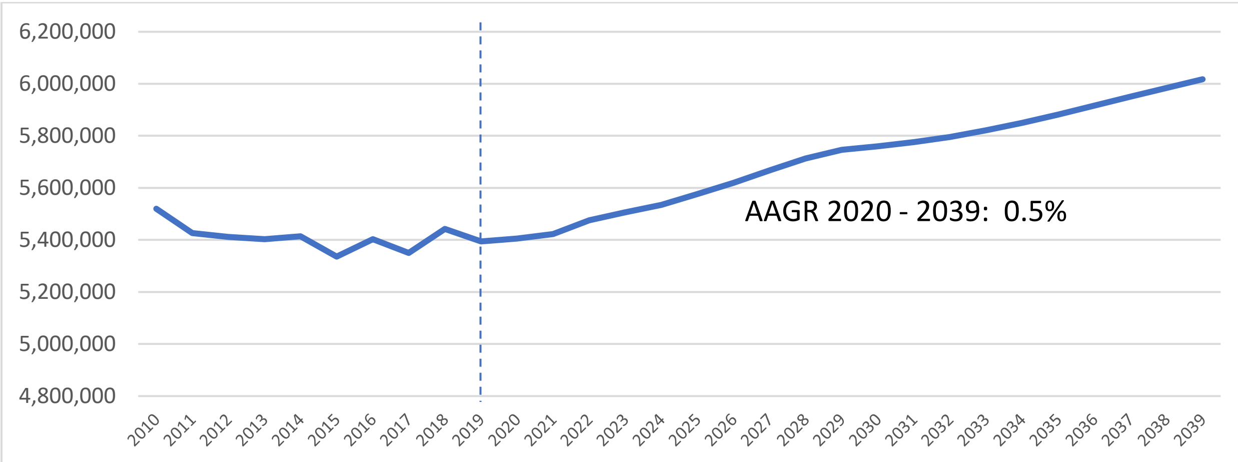


Figure 4.14 | Commercial Average Use



Commercial sales are projected to grow at an average annual rate of 0.5% as demonstrated in Figure 4.15.

Figure 4.15 | Commercial Sales



4.3.3 Industrial Sector

The Industrial Sector is comprised of demand metered customers larger than 500 kW. These customers all receive three phase primary service with IPL-owned transformers and other substation equipment located on the customer premises. IPL serves roughly 200 of these customers with total energy usage at around 22% of total IPL sales.

The primary economic drivers for IPL's Industrial forecast are Marion County manufacturing GDP (Figure 4.16) and Marion County manufacturing employment (Figure 4.17). Over the IRP period, manufacturing GDP is anticipated to increase at an average annual growth rate of 1.57% while employment is anticipated to decline at a rate of -0.53% annually. As noted earlier in this section, the economic input used in the forecast is weighted more heavily to employment resulting in a variable with an average annual growth rate of 0.93%. Figure 4.18 exhibits the trend in the economic variables.

Figure 4.16 | Indianapolis Manufacturing GDP

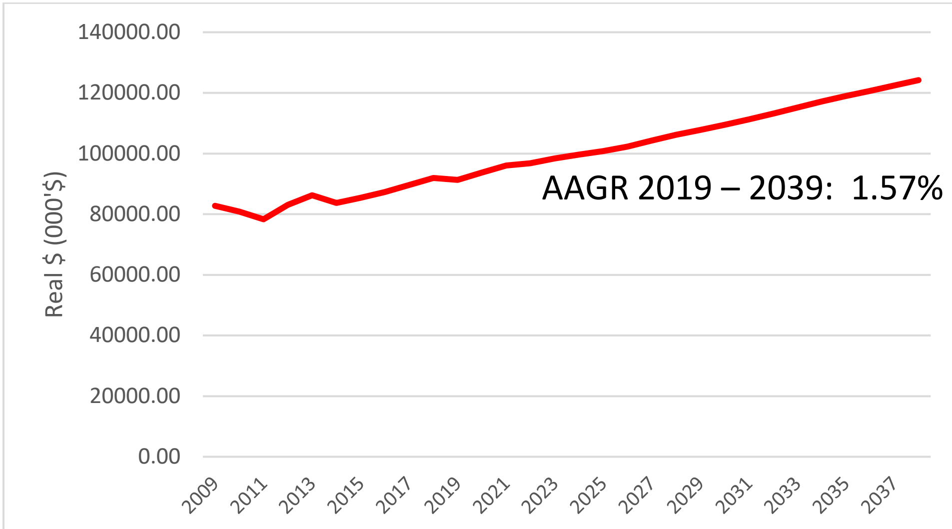


Figure 4.17 | Indianapolis Manufacturing Employment

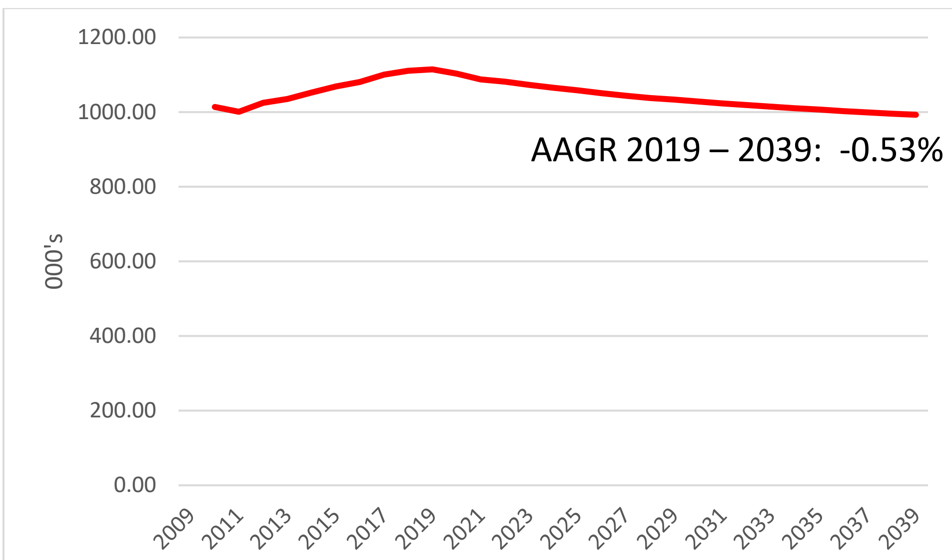
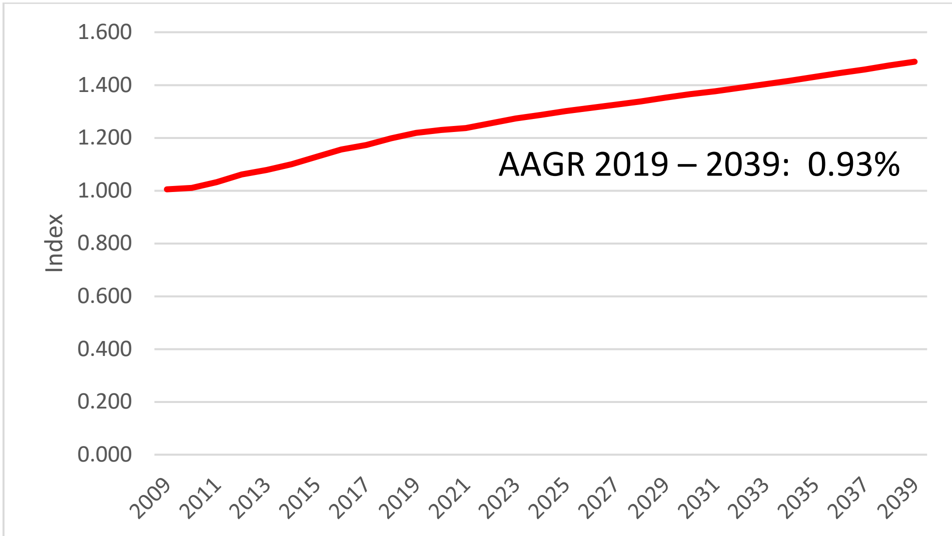


Figure 4.18 | Weighted Economic Variable



Confidential Attachment 4.7a-c provides the energy forecast drivers and Attachment 4.8 provide the peak forecast drivers and input data.

IPL exogenously adjusted the load forecast for anticipated customer loads larger than 5MW. It is assumed customers this large are not being picked up in the growth exhibited in the Moody's economic input data and therefore the load forecasting regression model. These customer additions are tracked by IPL's Strategic Accounts group, who regularly assist large industrial customers with billing items. The following customer additions in Figure 4.19 are included in the Industrial forecast:

Figure 4.19 | Expected (MW) Additions by IPL Industrial Customer

Company	2020	2021	2022	2023
Customer #1	2.5	2.5	2.5	2.5
Customer #2	5	5	5	0
Customer #3	0	5	5	0
Customer #4	6.25	6.25	0	0
Total	13.75	18.75	12.5	2.5

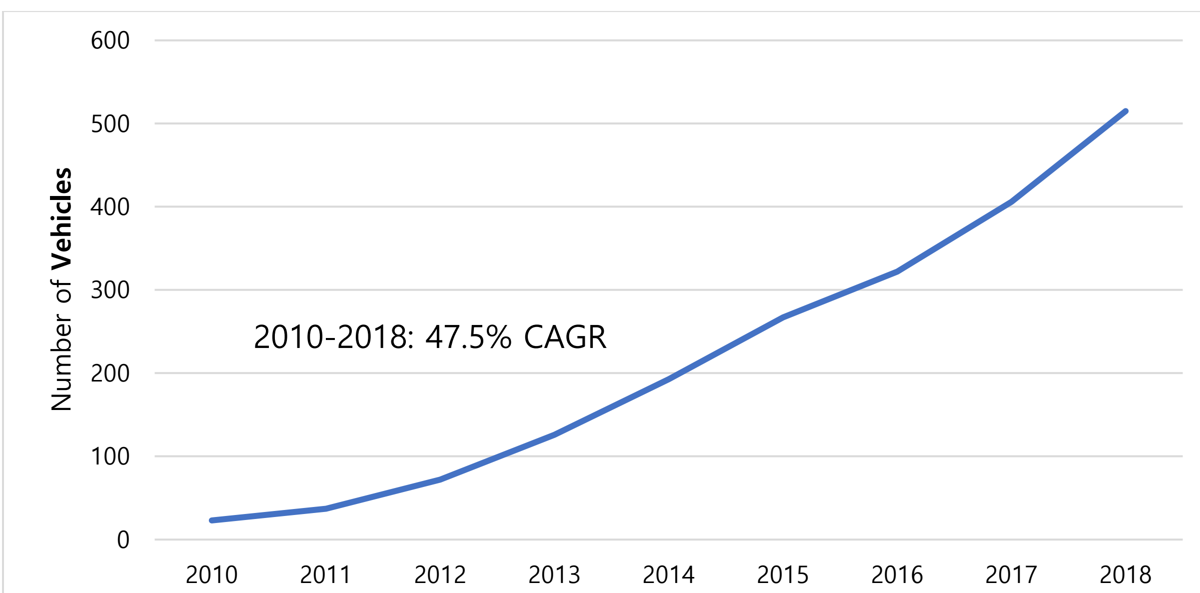
4.4 Electric Vehicles and Distributed Solar

Beneficial electrification of transportation is consistently identified as a significant means by which to reduce environmental impacts and improve transportation efficiency. The market for Electric Vehicles ("EV") is expected to grow rapidly, driven by declining battery costs and improved performance. Given their energy conversion efficiency, EVs are expected to eventually be significantly less costly and less polluting to operate. This increased EV adoption has the potential to result in significant measurable future grid impacts. Eventually, controlled EV charging may also serve as a resource in grid management. IPL expects that this trend of increased EV adoption will also be realized in our service territory over the next several years.

As Figure 4.20 below illustrates, the number of EVs in our service territory continues to grow at a rapid rate, but in total remains relatively small with approximately 500 EVs registered in the City of Indianapolis as of late 2018.

With approximately 515,300 vehicles registered in the greater Indianapolis area, the penetration rate remains below 0.01%. Given the relatively low EV penetration to date, IPL has experienced no material impacts on the distribution system impacts, but as discussed below we are continuing to monitor and assess necessary infrastructure upgrades as EV adoption market share increases.

Figure 4.20 | Historical Light Duty EV Fleet Growth



To better understand EV impacts and provide innovative solutions for customers, IPL has undertaken significant efforts in this area. IPL first implemented an Electric Vehicle ("EV") program in 2011. This program resulted in integrated charging infrastructure in homes, business and public parking facilities. The initial investments were accomplished in part, with partial Smart Grid Investment Grant ("SGIG") funding support from the U.S. Department of Energy ("DOE") and the State of Indiana Office of Energy Development. The funding resulted in the deployment of 162 charging stations installed in local homes and businesses.

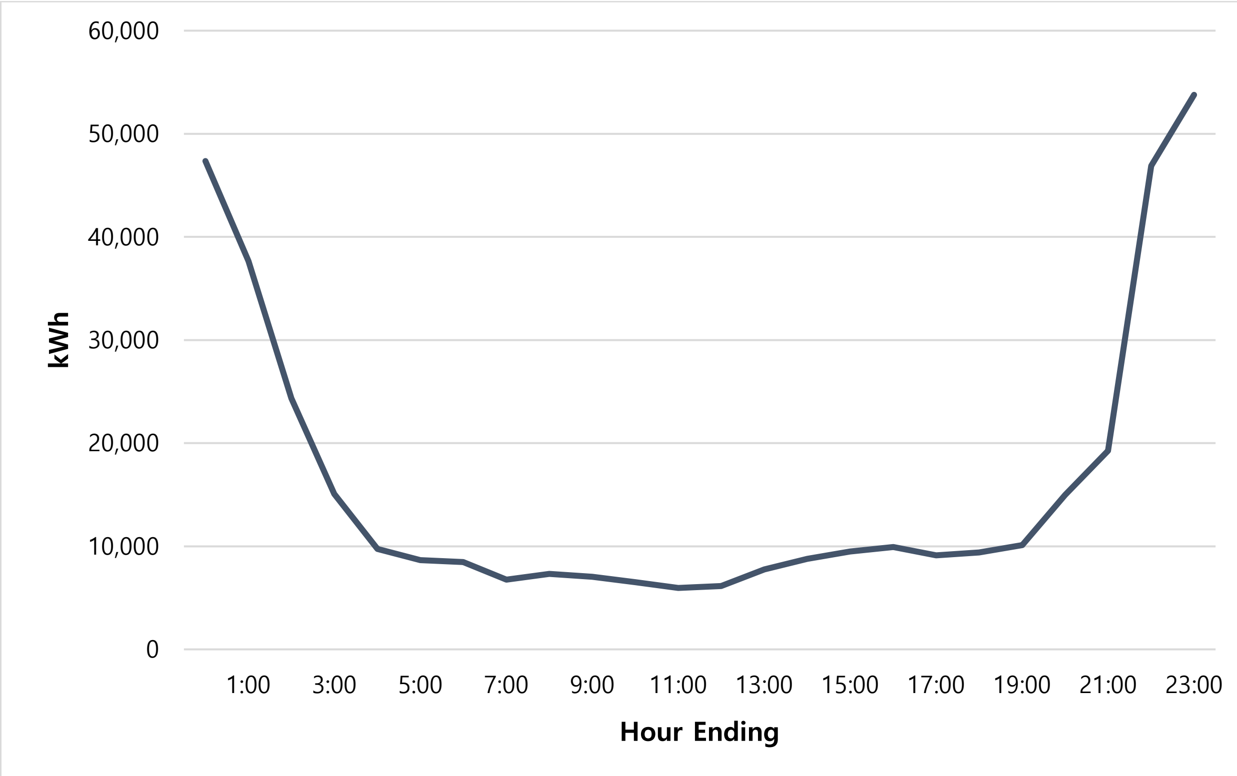
IPL has both a Time of Use ("TOU") EVX rate for customer premises and a public EVP rate for public charging stations. At present, approximately 130 customers participate in Rate EVX. The Rate EVX Rate schedule is shown in Figure 4.21.

Figure 4.21 | IPL EVX Rate Schedule

		Non-Holiday Weekends	Holidays & Weekends	Cents/kWh
Summer (Jun-Sep)	Peak	2pm - 7pm		12.150
	Mid-Peak	10am - 2pm; 7pm - 10pm	10am-10pm	5.507
	Off-Peak	12am - 10am; 10pm - 12am	12am - 10am; 10pm - 12am	2.331
Winter (Jan-May; Oct-Dec)	Peak	8am - 8pm	8am - 8pm	6.910
	Off-Peak	12am - 8am; 8pm - 12am	12am - 8am; 8pm - 12am	2.764

A representation of the Rate EVX charging patterns is shown in the graph below. As the graph illustrates, the vast majority of vehicle charging under IPL's Rate EVX occurred off peak. IPL found that approximately 92% of the charging occurred during off peak periods and only about 8% of the charging occurred during the Summer Peak and Mid-Peak periods. While participation and usage of the Rate EVX usage remain modest, IPL believes that the results demonstrate customers' willingness to charge off-peak in recognition of the TOU rate structure.

Figure 4.22 | EV Charging Curve – IPL Electric Vehicle Rates



The public EV rate (Rate EVP) is based upon a flat fee of $2.50 regardless of the duration of the charging session. Twenty-two (22) public chargers were initially deployed at eight (8) locations as a result of the pilot program. The public systems may be used by any customer or visitor to Indianapolis enabled by a key fob and credit card-based system. Since the pilot program concluded IPL has scaled back number of public chargers. There are currently three public chargers deployed at two stations. This reduction was made in part because of the large number of other public charging stations that have been deployed by other local entities, such as parking garages. While public charging remains less robust than might be expected, it does serve to mitigate range anxiety for EV drivers.

The City of Indianapolis asked IPL in 2013 to support its plan to implement an all-electric car sharing program with the City's partner, Bolloré Group/BlueIndy for up to 500 EVs at 200 electric vehicle charging station locations. As of November 30, 2018, 92 locations have been installed. Also, as of this date, there were 455 vehicle chargers and 196 vehicles deployed. See Attachment 4.9 for the report that summarizes BlueIndy activities. This is the final report that was filed pursuant to the Order in Cause No. 44478.

4.4.1 Electric Vehicle Forecast

For purposes of the IRP, IPL engaged the consulting firm of MCR Performance Solutions ("MCR") to assist us in developing a forecast of the market potential for EVs (as well as Solar PV) in the IPL service territory. MCR made a considerable effort to understand EV market share and penetration rates in the IPL service territory.

The EV forecasting process began with MCR assembling pertinent material from its existing library of work related to EV from several jurisdictions; conducting preliminary research to begin understanding the Indianapolis Power & Light Company ("IPL"), Indianapolis Indiana and national policy context; and current EV market penetration. This included developing an understanding of what utility rate and state policy structures exist, the current and known future status of federal tax incentives, what the general size of the existing EV fleet, and how IPL treated EVs in previous IRPs. Outcomes of this first work step included:

- Assembly of the IHS/Polk registered automobile census for the IPL service territory
- Compilation of an overview of the IPL service territory and customer base (i.e., customer population by rate and segment)
- Summary of pertinent rate structures
- Summary of federal tax incentive structures
- Development of carinsurance.com and kbb.com data on driving behavior, EV pricing and availability of EVs in Indiana and the IPL service territory
- Development of fueleconomy.gov EV efficiency in kWh per 100 miles driven
- Alignment that the general direction for the forecasting methodology would be a spreadsheet-based approach or an existing online tool or tools
- Alignment that the forecasting methodology would first define prototypical system characteristics such as size, cost, etc. and then apply a forecast of the number of units of EV to the prototypical systems to generate the MW and MWh forecasts

4.4.2 Literature Review and Prototypical EV

To develop recommended approaches to prepare the EV forecast for IPL, MCR conducted a literature review on EV adoption rates and forecasting techniques. Recognizing the IndyGo public transportation system is progressive with respect to electrification of its bus fleet, MCR also assembled secondary and primary (i.e., interview-based) data on the IndyGo bus electrification plans. Lastly, MCR undertook a web-based review of the status of electrified medium- and heavy-duty trucks.

MCR's literature review examined over 60 resources on EVs, from a combination of online research, and mining of IPL and MCR resource libraries. The methodology for conducting the literature review was to first assemble a complete bibliography of references and then conduct an initial, brief review of each to determine whether their vintage, geographic scope and applicability to our primary goal of finding spreadsheet-based methodologies or online tools and readily available data rendered them appropriate for deeper review by MCR's subject matter experts. For the resources escalated for subject matter expert review, MCR's subject matter experts first confirmed or rejected the appropriateness of the references and then examined more deeply those that were confirmed for such review. The output of the literature review included summaries of 16 EV resources that MCR identified as having the most relevance for developing forecasts for IPL.

With respect to IndyGo MCR developed detailed assumptions on the specific buses and associated charging patterns as well as the timing of IndyGo replacement of existing diesel buses with electric. The IndyGo transition to an electric bus fleet began in earnest with the opening of the all electric Red Line route in Q3 of 2019 and will continue will additional all electric bus routes over the next few years.

With respect to medium- and heavy-duty trucks, MCR concluded that these technologies and the deployment of them are at too early a stage to attempt to include them in a forecast, but we did identify for IPL local manufacturers of interest (i.e., Navistar/Volkswagen) as well as potential early adopters of the technology as it emerges (i.e., the FedEx hub at Indianapolis International Airport).

Development of prototypical EV systems and detail on the IndyGo bus transition was based on the following primary resources:

- EV: fueleconomy.gov, carinsurance.com, kbb.com, IHS/Polk data, IPL actual EV charging data
- IndyGo: 2017 IndyGo Capital Plan, BYD[9] manufacturer data and IndyGo staff interviews

Assumptions for the prototypical EV and the busses to be deployed on the IndyGo bus system are summarized below in Figure 4.23 and Figure 4.24.

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[9] BYD is a battery electric bus manufactured by the Chinese automaker BYD Auto. BYD was chosen by INDYGO! to supply the busses for the be the bus supplier for Rapid Transit system that is being built out in Indianapolis.

Figure 4.23 | EV Summary and Prototypical EV

Attribute	Value	Source
Count	515	IPL-provided IHS/Polk
kWh/100 miles	31	www.fueleconomy.gov
Annual miles	11,655	www.carinsurance.com
Annual kWh	3,613	= 31 * (11,655/100)
Price	$40,267	www.kbb.com

Figure 4.24 | IndyGo Summary and Plan

Attribute	60’ BYD BRT	40’ Fleet
Current quantity	2	21
2032 quantity	56	144
Range	275	250
Miles/year	45,600	45,600
Charger	40 kW x 2	40 kW x 2
Battery kWh	652	489
Charge time hours	6	4.5
Cost	$1,200,000	$675,000

4.4.3 Forecasting Methodology

Upon completion of the literature review, assembly of EV and IndyGo summaries, and development of the prototypical systems, MCR conducted a workshop with the IPL project team to review the results and discuss application of them to come to alignment on the specific approach MCR would take to developing the forecasts. Recall that two fundamental methodological decisions were made at the outset:

1. Forecasts would be developed for the number of units of EV, then the prototypical system attributes and IPL charging meter data-based EV consumption profiles would be applied.
2. The approach to developing the unit forecasts would be either spreadsheet-based or rely upon existing online calculators or tools.

The general approach agreed upon was to utilize existing, recent national forecasts and adjust or scale them to the IPL service territory.

EV Forecasting Methodology

The forecast of units of EV was developed by using a "percent of fleet" approach for light duty vehicles and then adding the known (expected) IndyGo bus data. The Edison Electric Institute (EEI) EV forecast was identified as the primary source because it is a highly-regarded and frequently cited meta forecast based on five other EV forecasts. However, the time horizon of the forecast extends only through 2030, so the relationship between the forecasted EV fleet size and that forecasted by Bloomberg New Energy Finance ("BNEF") through 2040 was utilized to extend the base EEI forecast to 2040.

United States Census Bureau projections, Marion County population projections from Indiana University, and the IHS/Polk vehicle registration data were all used to adjust and scale the modified EEI forecast to yield an IPL-specific unit forecast of numbers of light duty EV[10]. The modified EEI forecast provided annual national data on EV as a percent of total light duty vehicle fleet, which was scaled to IPL's territory based on the Marion County population data and growth rates. Because light duty EV purchase decision-making is known to be heavily influenced by median household income, a final adjustment

[10] Because the number of EV registered in the IPL service territory as of 2018 is unusually low relative to the adjusted and scaled EEI forecast, and recognizing that cost equivalence of EV and internal combustion vehicle prices can be expected in approximately 2026, the forecast is started with the adjusted and scaled EEI forecast number of vehicles rather than the actual 2018 IPL-area IHS/Polk number in order to prevent the numbers of EV to be expected in later years from being unrealistically low.

was made to reflect the Marion County median household income as a percentage of the national median household income. IndyGo bus quantities were reached by 2032 based on annual numbers of additions discussed with IndyGo staff during interviews.

IPL Rate EVX costing periods, IPL metered EV charging data, and the prototypical EV attributes in Figure 4.23 enabled conversion of numbers of units of light duty EV to on-peak and off-peak MWh and MW. Likewise, given the IndyGo bus attributes in Figure 1.20 and an assumption of overnight (i.e., 10:00 pm to 4:00 am) charging, and IPL's Rider 8 – Off-Peak Service costing periods, the MWh and MW forecasts for the buses were developed.

MCR created an average 8,760-hour EV charging profile using IPL EVX customer's AMI meter data from 2018. IPL utilized this load shapes to spread the monthly on and off peak EV forecasts out to every hour for the IRP model.

PV Forecasting Methodology

The PV forecasting process closely mirrored the approach MCR took in developing the EV forecast described above. Again, MCR assembled pertinent material from its existing library of work related to PV; and by conducting preliminary research to begin understanding the Indianapolis Power & Light (IPL), Indianapolis Indiana and national policy context. The current market penetration for PV was also considered. MCR developing an understanding of IPL's current rate structure and state policy, as well as federal tax policy. Outcomes of this first work step in addition to the outcomes discussed above included:

- Assembly of the IPL net metered, renewable energy production (Rate REP), and cogeneration and small power production (Rate CGS) inventories of installed solar
- Summary of Rate CGS and Rider 9 (Net Metering) rate structures
- Receipt of the National Renewable Energy Laboratory (NREL) Advance Technology Baseline (ATB) report on solar system pricing
- Alignment that the general direction for the forecasting methodology would be a spreadsheet-based approach or an existing online tool or tools
- Alignment that the forecasting methodology would first define prototypical system characteristics such as size, cost, etc. and then apply a forecast of the number of units of PV to the prototypical systems to generate the MW and MWh forecasts

The PV unit forecast was developed using the December 2018 Solar Energy Industries Association (SEIA) and Wood Mackenzie Power and Renewables Solar Market Update Report, often referred to as the Greentech Media or GTM report, as the primary source. The specific methodology was a straightforward matter of developing the 2019-2023 GTM report compound annual growth rates for residential and commercial & industrial solar installations and applying that to the number of residential and commercial & industrial net metered installations in the IPL service territory as of year-end 2018.

IPL Rate CGS costing periods and PVWatts 8,760 annual hour production data for the 8-kW prototypical residential system and 125-kW prototypical commercial & industrial system as described in Figure 4.25 were used to develop the on-peak MWh, off-peak MWh and peak MW forecasts.

IPL created an average 8,760-hour PV profile using IPL's Rate REP solar customer data. IPL used this profile to spread MCR's monthly PV forecast out to every hour for the IRP model.

Assumptions for the prototypical PV system are Figure 4.25.

Figure 4.25 | PV Summary and Prototypical PV Systems

Attribute	Residential	C&I
IPL NEM count (Adjusted EIA counts from IPL 2018 NEM file)	177	21
Size (kW - DC)	8	125
Panel type	Anti-reflective crystalline silicon	Anti-reflective crystalline silicon
Array type	Fixed	Fixed
Capacity factor	15.8%	15.8%
Production basis	PVWatts – 46241	PVWatts – 46241
System cost/watt	$2.70	$1.83
System cost	$21,600	$228,750
Annual O&M	$192	$2,250

4.4.4 EV and Distributed Solar Forecasting Results

The final IPL 2020-2040 forecasts of numbers of units and capacity by technology type are summarized in Figure 4.26, and the energy (MWh) by technology type are summarized in Figure 4.27. By the end of the study period, there are expected to be nearly 200,00 EVs in the IPL service territory, resulting in

32 MW of demand on the IPL system. Solar PV is expected to provide approximately 21 MW of supply by the end of the study period.

Figure 4.26 | IPL Forecast of EV & PV Counts and Demand

	EV Count	EV Summer kW	EV Non-Summer kW	PV Count	PV MW
2020	5,621	901	1,226	240	4.34
2021	7,843	1,255	1,709	264	4.65
2022	9,968	1,596	2,174	291	4.98
2023	11,939	1,913	2,605	321	5.34
2024	15,469	2,481	3,379	354	5.72
2025	19,543	3,138	4,273	390	6.13
2026	24,364	3,915	5,331	430	6.56
2027	30,566	4,915	6,693	474	7.04
2028	37,743	6,073	8,269	524	7.67
2029	46,268	7,448	10,142	579	8.34
2030	56,148	9,043	12,313	640	9.07
2031	68,348	11,012	14,995	707	9.84
2032	82,173	13,246	18,036	761	10.66
2033	97,192	15,673	21,340	863	11.55
2034	112,667	18,173	24,745	953	12.51
2035	128,128	20,671	28,147	1,053	13.54
2036	143,283	23,120	31,481	1,163	14.65
2037	157,912	25,484	34,700	1,285	15.86
2038	171,925	27,748	37,783	1,421	17.30
2039	185,298	29,909	40,726	1,571	18.85
2040	197,177	31,829	43,339	1,737	20.53

Note: The EV forecast kW are for Rate EVX.

Figure 4.27 | 2020 – 2040 IPL Forecast of EV and PV MWh

	EV Summer Peak MWh	EV Summer Mid-Peak MWh	EV Summer Off-Peak MWh	EV Non-Summer Peak MWh	EV Non-Summer Off-Peak MWh	EV Annual MWh	PV Peak MWh	PV Off-Peak MWh	PV Annual MWh
2020	500	1,076	6,273	3,610	13,506	24,965	4,388	1,619	6,007
2021	697	1,500	9,129	5,031	19,595	35,952	4,701	1,734	6,435
2022	887	1,908	11,277	6,399	24,255	44,726	5,035	1,858	6,893
2023	1,063	2,287	13,296	7,668	28,631	52,944	5,399	1,992	7,391
2024	1,378	2,966	16,620	9,947	35,883	66,795	5,783	2,134	7,917
2025	1,743	3,751	20,399	12,578	44,140	82,611	6,197	2,286	8,483
2026	2,175	4,680	24,803	15,693	53,776	101,126	6,632	2,447	9,079
2027	2,730	5,875	30,362	19,702	65,961	124,630	7,114	2,626	9,740
2028	3,374	7,259	36,738	24,343	79,945	151,657	7,754	2,861	10,615
2029	4,138	8,903	44,241	29,856	96,417	183,555	8,432	3,111	11,543
2030	5,023	10,809	52,878	36,248	115,389	220,348	9,170	3,383	12,553
2031	6,117	13,163	63,456	44,142	138,644	265,523	9,948	3,670	13,618
2032	7,358	15,833	75,151	53,094	164,413	315,848	10,777	3,976	14,753
2033	8,706	18,734	87,718	62,822	192,132	370,112	11,677	4,308	15,985
2034	10,095	21,723	100,667	72,845	220,694	426,023	12,648	4,666	17,314
2035	11,483	24,709	113,604	82,859	249,229	481,884	13,689	5,050	18,739
2036	12,843	27,636	126,285	92,675	277,200	536,639	14,811	5,464	20,275
2037	14,156	30,462	138,525	102,150	304,200	589,493	16,034	5,916	21,950
2038	15,414	33,168	150,251	111,227	330,063	640,122	17,490	6,453	23,943
2039	16,615	35,751	161,440	119,888	354,744	688,439	19,057	7,031	26,088
2040	17,681	38,045	171,380	127,583	376,669	731,358	20,756	7,658	28,414

4.4.5 Distributed Solar (Non-Net Metered / Rate REP)

Most IPL's other distributed energy resources are related to the IPL feed in tariff (Rate REP). Rate REP was initially offered in 2011 and is fully subscribed and not available to new participants.

4.5 Load Model Performance and Analysis

170 IAC 4-7-4(2) 170 IAC 4-7-5(a)(10)

IPL periodically evaluates the load forecast model performance (1) when the model is created, (2) on a monthly basis as a variance analysis, and (3) after-the-fact as a year-end comparison.

During forecast development a number of models are analyzed at the rate level. The adjusted R-squared statistic, Mean Absolute Percent Error ("MAPE"), the Durbin-Watson statistic, and reasonableness of each model to IPL are statistically evaluated. The target adjusted R-squared values better than 90%; this is accomplished in nearly all cases. Further, MAPE needs to be less than 2%, and the Durbin-Watson statistic is targeted around 2.0. IPL considers independent variables with T-statistics of at least 2.0 acceptable. This judgment is somewhat subjective and dependent upon the implied importance of the variable. Please see Attachment 4.10 for summary of these model statistics.

Evaluation of the variance of energy sales and peak demand is completed each month and consider the impact of weather adjustments. IPL's forecasting staff uses this information to evaluate model performance. If the monthly variance moves reasonably with current "knowns" like economic factors and/or weather, a conditional approval supports the forecast. However, should variance move contrary to "knowns," an investigation of possible bias and other elements is undertaken. A similar determination, but with greater detail, is made at year-end. Actual and weather-adjusted results are compared to the forecasted values generated each of the previous five years. This is done with respect to energy sales at the class level, namely Residential, Small C&I, and Large C&I. Summer peak and winter peak, both actual and weather-adjusted, are reviewed in similar fashion.

The Mean Percent Error ("MPE") is used to evaluate overall forecast performance after the fact. Two interesting comparisons that gauge IPL's forecasting ability are those that compare weather-adjusted annual GWh sales and weather-adjusted summer peak to their respective forecasts. IPL's one-year-out energy forecast, as measured by MPE, is on average, within 1.5% of weather-adjusted sales. The summer MPE peak forecast averages 3.9%. IPL targets a one-year forecast error of less than 2%. Occasionally, rapidly changing external conditions, such as the extreme winter/polar vortex of 2013-2014, can cause fluctuations that exceed this bandwidth. However, reviewing forecast updates on a quarterly basis allows IPL to make both tactical adjustments in the short-term and initiate additional scenario analyses in the long-term. Figure 4.28 and Figure 4.29 highlight IPL's overall retail energy sales and summer peak demands forecast performance, respectively, for the last 10 years. The remainder of the forecast error analyses at the class level may be found in Attachment 4.9.

Figure 4.28 | Forecast Error Analysis: Weather-Adjusted Energy Sales vs. Forecasts

ANNUAL "INDIANAPOLIS ONLY" GWH SALES
Adjusted & Forecasted

		Forecast Made:				
For	Adjusted Sales *	One Year Ago	Two Years Ago	Three Years Ago	Four Years Ago	Five Years Ago
2009	14,296.266	15,208.790 6.4%	15,472.539 8.2%	15,612.025 9.2%	15,932.337 11.4%	15,838.873 10.8%
2010	14,120.637	14,287.148 1.2%	15,356.932 8.8%	15,702.517 11.2%	15,817.438 12.0%	16,173.497 14.5%
2011	14,010.057	14,172.293 1.2%	14,420.894 2.9%	15,520.059 10.8%	15,914.802 13.6%	16,020.434 14.3%
2012	14,011.544	14,268.134 1.8%	14,391.694 2.7%	14,717.444 5.0%	15,705.912 12.1%	16,149.633 15.3%
2013	13,878.196	14,118.020 1.7%	14,263.240 2.8%	14,491.940 4.4%	14,783.227 6.5%	15,691.466 13.1%
2014	13,696.867	13,999.408 2.2%	14,241.352 4.0%	14,411.550 5.2%	14,627.775 6.8%	14,917.986 8.9%
2015	13,728.657	14,085.083 2.6%	14,141.772 3.0%	14,409.551 5.0%	14,526.255 5.8%	14,700.724 7.1%
2016	13,447.981	13,999.475 4.1%	14,140.651 5.2%	14,204.751 5.6%	14,567.446 8.3%	14,612.900 8.7%
2017	13,434.558	13,838.176 3.0%	14,015.988 4.3%	14,089.805 4.877%	14,175.427 5.5%	14,514.876 8.0%
2018	13,433.004	13,412.786 -0.2%	13,763.267 2.5%	14,003.301 4.2%	14,001.728 4.2%	14,114.648 5.1%

Mean % Error	2.4%	4.4%	6.6%	8.6%	10.6%
Mean Absolute % Error	2.4%	4.4%	6.6%	8.6%	10.6%

Figure 4.29 | Forecast Error Analysis: Weather-Adjusted Summer Peak Demands vs. Forecasts

SUMMER PEAK DEMANDS
Actual & Forecasted

		Forecast Made:									
For	Actual Peak Demand	One Year Ago	Two Years Ago	Three Years Ago	Four Years Ago	Five Years Ago	Six Years Ago	Seven Years Ago	Eight Years Ago	Nine Years Ago	Ten Years Ago
2009	2924	3218	3236	3293	3236	3313	3257	3321	3536	3457	3419
		10.0%	10.7%	12.6%	10.7%	13.3%	11.4%	13.6%	20.9%	18.2%	16.9%
2010	2901	3117	3253	3274	3343	3281	3354	3300	3364	3590	3514
		7.4%	12.1%	12.8%	15.2%	13.1%	15.6%	13.8%	16.0%	23.8%	21.1%
2011	2894	2943	3173	3287	3312	3391	3327	3395	3344	3408	3645
		1.7%	9.6%	13.6%	14.4%	17.2%	15.0%	17.3%	15.5%	17.8%	26.0%
2012	2899	2938	3001	3253	3320	3350	3445	3372	3429	3388	3453
		1.4%	3.5%	12.2%	14.5%	15.6%	18.8%	16.3%	18.3%	16.9%	19.1%
2013	2839	2928	2975	3047	3311	3352	3388	3489	3418	3484	3432
		3.1%	4.8%	7.3%	16.6%	18.1%	19.3%	22.9%	20.4%	22.7%	20.9%
2014	2880	2937	2981	3004	3064	3355	3385	3426	3536	3463	3533
		2.0%	3.5%	4.3%	6.4%	16.5%	17.5%	19.0%	22.8%	20.2%	22.7%
2015	2849	2945	2984	3031	3003	3073	3400	3418	3464	3584	3509
		3.4%	4.7%	6.4%	5.4%	7.8%	19.3%	20.0%	21.6%	25.8%	23.2%
2016	2835	2841	2975	3026	3,047	2989	3082	3445	3451	3502	3630
		0.2%	4.9%	6.8%	7.5%	5.4%	8.7%	21.5%	21.7%	23.5%	28.0%
2017	2815	2866	2865	2983	3051	3,055	2978	3087	3494	3485	3541
		1.8%	1.8%	6.0%	8.4%	8.5%	5.8%	9.7%	24.1%	23.8%	25.8%
2018	2812	2861	2864	2882	2982	3072	3,079	2962	3092	3540	3519
		1.7%	1.8%	2.5%	6.1%	9.3%	9.5%	5.3%	10.0%	25.9%	25.2%

Mean % Error	3.3%	5.8%	8.4%	10.5%	12.5%	14.1%	15.9%	19.1%	21.9%	22.9%
Mean Absolute % Error	3.3%	5.8%	8.4%	10.5%	12.5%	14.1%	15.9%	19.1%	21.9%	22.9%

Section 5: Resource Options

170 IAC 4-7-4(11)

5.1 Existing IPL Resources

5.1.1 Existing Supply-Side Resources

170 IAC 4-7-4(4) 170 IAC 4-7-6(a)(1) 170 IAC 4-7-6(a)(2)

IPL's resource portfolio has changed dramatically over the last several years. Coal made up 79% of the IPL fleet in 2007, but by 2018 only represented 44% of the nameplate capacity. Through the resource planning process, IPL has sought to find the reasonable least-cost solution to meet the needs of its customers. Prudent portfolio management suggests that diversity of resource options helps to mitigate cost volatility. Figure 5.1 provides an overview of recent major changes to IPL's portfolio.

Figure 5.1 | Recent Significant Changes to IPL's Portfolio

2009	2011	2013-2015	2016	2016	2018
Signed 100 MW PPA at Hoosier Wind Park in NW Indiana	Signed 200 MW PPA at Lakefield Wind Farm in Minnesota	Signed 96 MW PPA for solar in Indianapolis through Rate REP	Retired 260 MW of coal at Eagle Valley	Finalized conversion of 630 MW of coal-fired generation at Harding Street to natural gas	Eagle Valley 671 MW Gas-Fired Combined Cycle Plant Completed

Figure 5.2 shows the Installed Capacity ("ICAP") value and Unforced Capacity ("UCAP") value of IPL's resources. ICAP values are based on annual unit testing.

Figure 5.2 | IPL Resources Installed and Unforced Capacity Credit

	ICAP MW	UCAP MW
Coal	1,690	1,600
Gas	1,746	1,634
Oil/Diesel	38	37
Wind/Solar	396	54
Other	55	55
Total	3,926	3,380

Each resource has an estimated useful life with a corresponding age-based retirement year. This 2019 IRP analyzes the calendar years 2020 through 2039. Figure 5.3 illustrates the age-based retirement years falling within this IRP study period in terms of UCAP. It also shows IPL's capacity position transitioning from having excess capacity to having a capacity deficiency relative to its peak load and reserve margin. The first year this shift can be seen is 2031 after two of the Harding Street units retire.

Figure 5.3 | IPL UCAP Net Position using Age-Based Retirement Years

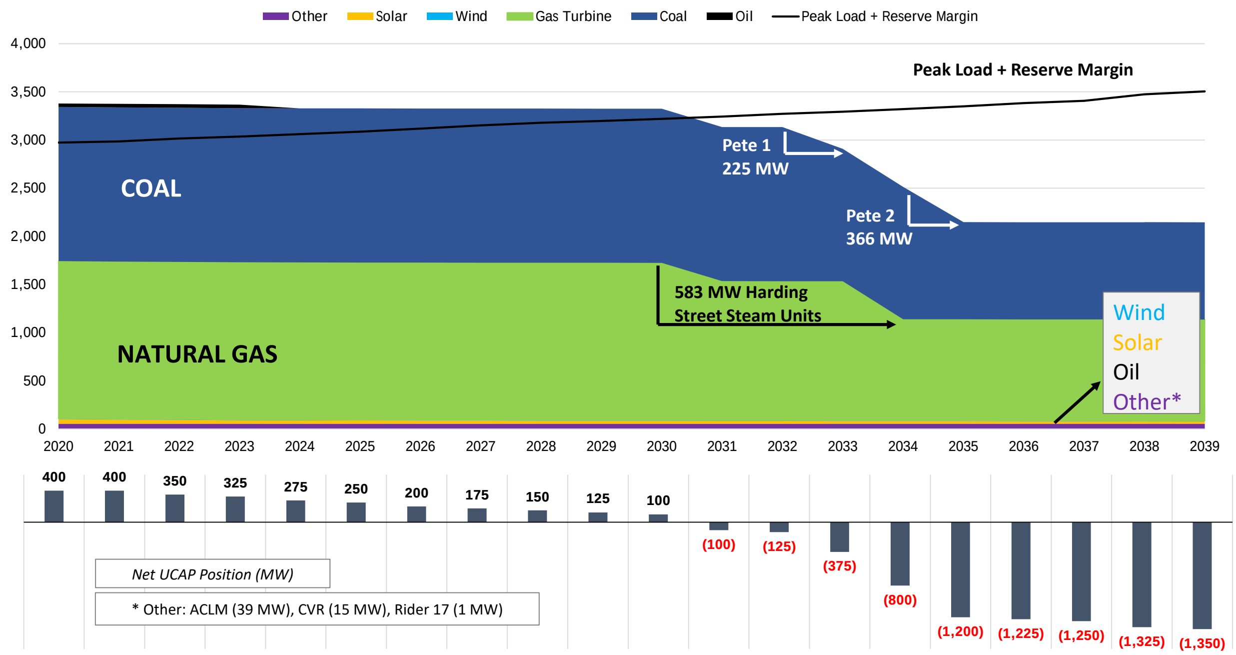


Figure 5.4 and Figure 5.5 illuminate more detail into IPL's existing thermal generating resources.

Figure 5.4 | IPL's Existing Coal Assets

Unit	Name	Type	ICAP MW	UCAP MW	In-Service Year	Estimated Last Year In-Service
Petersburg						
PETE ST1	Pete 1	Coal	235	225	1967	2032
PETE ST2	Pete 2	Coal	401	366	1969	2034
PETE ST3	Pete 3	Coal	518	486	1977	2042
PETE ST4	Pete 4	Coal	536	523	1986	2042
Total Coal:			1,690	1,600		

Figure 5.5 | IPL's Existing Gas and Oil Assets

Unit	Name	Type	ICAP MW	UCAP MW	In-Service Year	Estimated Last Year In-Service
Eagle Valley						
EV CCGT	Eagle Valley	CCGT	671	617	2018	2055
Harding Street						
HS 5G	Harding Street 5	Gas ST	100	95	1958	2030
HS 6G	Harding Street 6	Gas ST	99	94	1961	2030
HS 7G	Harding Street 7	Gas ST	415	394	1973	2033
HS GT4	Harding Street GT4	Gas CT	74	70	1994	2044
HS GT5	Harding Street GT5	Gas CT	74	70	1995	2045
HS GT6	Harding Street GT6	Gas CT	154	143	2002	2052
HS GT1 & GT2	Harding Street GT1&2	Oil	38	37	1973	2023
Georgetown						
GTOWN GT1	Georgetown 1	Gas CT	79	75	2000	2050
GTOWN GT4	Georgetown 4	Gas CT	79	76	2001	2052
Total Natural Gas:			1,746	1,634		
Total Oil:			38	37		

Figure 5.6 shows both the nameplate capacity and UCAP value for IPL's wind and solar PPAs. IPL's Solar REP is on the distribution system and therefore reduces load rather than participates as a generating resource. IPL does not receive direct UCAP capacity credit for its Solar REP and does not offer solar PPA generation directly into the MISO market, but its capacity still contributes towards reducing IPL's peak demand. It's also important to realize that IPL's Solar REP UCAP decreases with time due to the saturation of solar in the MISO footprint. Incremental solar shifts the load profile, thus reducing solar's effectiveness at coinciding with peak demand. This is covered in more detail in Section 5.3.2. IPL receives capacity credit for Hoosier Wind Park commiserate with MISO's Zone 6 ELCC. IPL does not have firm transmission rights for its Lakefield Wind Park and so receives no capacity credit for this resource.

Figure 5.6 | IPL's Existing Renewable PPAs

Unit	Type	ICAP MW	UCAP MW	PPA Start	PPA Expiration
Wind and Solar					
Hoosier Wind Park (IN)	PPA	100	6.6	Nov-09	Nov-29
Lakefield Wind (MN)	PPA	200	0	Oct-11	Oct-31
Solar (Rate REP) *	PPA	96	47.5	varies	2021-2030
Total Renewables:		396	54		

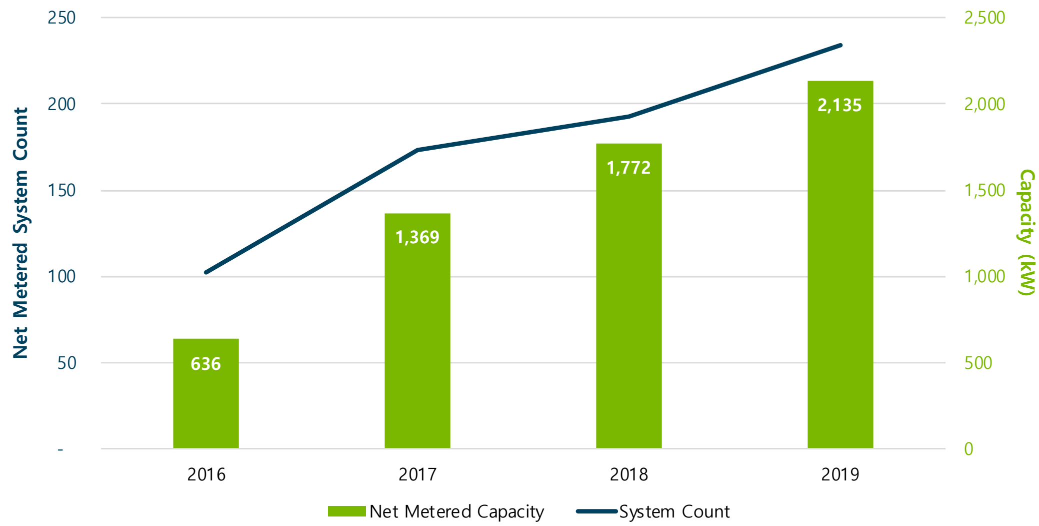
*IPL is using 47.5 MW for 2020, but this value decreases over time.

IPL's current PPA contracts expire within the IRP study period. It is assumed that these contracts will be renegotiated, and the resources will continue to perform in alignment with their historical generation.

Figure 5.7 summarizes the growth of net metered customers in the IPL Service territory, as of September 2019. IPL has experienced modest growth in PV net metered customers. Except for a federally funded 1 MW project, most net metered projects are relatively small solar installations.[11] Net metered capacity reduces IPL load requirements in terms of energy and does not materially affect capacity.

[11] All the Indiana IOUs file an annual net metering report with the IURC. The 2018 report published March 2019, is available at https://www.in.gov/iurc/files/2018%20Net%20Metering%20Required%20Reporting%20Summary.pdf.

Figure 5.7 | Summary of IPL Net Metering Participation



5.1.2 Existing Demand Side Resources

IPL's current portfolio of DSM resources (2018 – 2020) was approved on February 7, 2018 in Cause No. 44945. This comprehensive set of programs provides energy efficiency opportunities for all IPL customers.

Current Energy Efficiency Programs

The current energy efficiency programs and the actual 2018 evaluated energy savings of approximately 162,000 Net MWh are identified in Figure 5.8. Through the first eight months of 2019, the IPL energy efficiency and demand response programs have contributed an estimated 111,669 MWh of energy savings benefits and approximately 56.9 MWs of demand savings benefits[12]

The total 2019 net energy efficiency savings are forecast to be approximately 145,000 MWh.

[12] YTD gross savings from the August 2019 Scorecard as provided to the IPL Oversight Board ("IPL OSB"). Results are subject to Evaluation, Measurement & Verification ("EM&V") which will be completed after the program year.

Figure 5.8 | 2018 DSM Program Energy Savings

DSM Program	Evaluated 2018 Program Achievement (Ex Post Net kWh)*
Residential Programs	
Demand Response	68,609
Appliance Recycling	1,865,513
Community Based Lighting	8,014,916
Income Qualified Weatherization	2,256,228
Lighting & Appliances	20,125,603
Multifamily Direct Install	2,423,349
Peer Comparison	27,332,805
School Kits	4,003,124
Whole Home	4,027,393
Total Residential	**70,118,086**
Business Programs	-
Demand Response	-
Custom	14,639,238
Prescriptive	73,836,844
Small Business Direct Install	3,091,457
Total Business	**91,567,539**
Total All Programs	**161,685,625**

*Ex Post Net reflects the net impact of DSM programs following third party evaluation. More information can be found in the IPL 2018 Demand Side Management Portfolio Evaluation Report dated June 27, 2019 as filed with the Commission in Cause No. 44945.

IPL's ACLM ("CoolCents®") and Income Qualified Weatherization Programs are IPL's longest continually offered DSM programs. The Residential ACLM program has been offered since 2003 and represents the largest DSM program in terms of customer participation and peak demand reduction. As of the end of 2018, IPL has approximately 49,500 residential customers with load control switches or smart thermostats. In 2018 there were also approximately 430 load control switches installed at business customer's facilities. In total these devices contributed approximately 31.6 MW of demand reductions.[13]

[13] 2018 Demand Side Management Evaluation Report, Indianapolis Power & Light Company, June 27, 2019, Tables 13, 14 and 15, p. 10.

Of current offerings, the most significant DSM programs in terms of energy efficiency savings in 2019 are expected to be the Business Prescriptive Program (approximately 57,000 gross MWh savings through October 31, 2019) and the Residential Peer Comparison Report (with approximately 27,000 gross MWh savings through October 31, 2019).

Current Demand Response Programs

In addition to the energy efficiency DSM programs and the ACLM demand response program described above, IPL also has several Load Curtailment/Interruptible programs that are tariff offerings targeted to business customers. Since 2014 these programs have seen a significant decrease in participation and the amount of capacity that is being provided. The programs had mostly been targeted to customers that have emergency back-up generation. Customers were called upon from time to time to operate the emergency generation equipment on IPL's behalf to reduce load. However, the National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines ("RICE/NESHAP") rules caused most customer owned emergency generation to no longer be available to participate in utility sponsored programs due to air emission constraints. As a result of these EPA restrictions, the current level of participation in IPL's Load Curtailment / Interruptible programs is just under 1 MW as shown below.

IPL also has the capability to operate the Conservation Voltage Reduction systems as needed. This system can provide an additional 15.3 MW of load relief.

In summary, Figure 5.9 shows the demand response resources for which IPL received capacity credit from MISO totaling 55.0 MW in 2018. There is no end of useful life shown since IPL plans to support this program through customer enrollment and replacement technologies as needed throughout the study period.

Figure 5.9 | Existing DR program Contributions

Demand Response Type	ICAP Value (MW)
Air Conditioning Load Management	38.6
Rider 17: Curtailment Energy	1.1
Conservation Voltage Reduction	15.3
Total	55.0

5.2 Supply-Side Resource Options

170 IAC 4-7-4(6) 170 IAC 4-7-4(7) 170 IAC 4-7-4(31) 170 IAC 4-7-6(b)(3)(A)

Key Highlights for Supply-Side Resources
• IPL conducted thorough research to develop the cost and operational parameters of new supply-side resources. • New natural gas resources modeled included combined cycle, simple cycle gas turbines, and quick start technologies like aeroderivative turbines and reciprocating engines • Near-term costs for wind, solar, and storage were benchmarked to publicly available market bids • Future costs for wind, solar, and storage are expected to decrease in real terms through time, and future costs used information from NREL, IHS Markit, BNEF, and Wood Mackenzie to provide an average consensus for price trajectories through time

Below is a list of the supply-side resource options considered followed by a more detailed description of each technology:

Natural Gas

- Simple Cycle Combustion Turbine ("CT")
- Combined Cycle Gas Turbine ("CCGT")
- Aeroderivative Turbines ("Aero CT")
- Reciprocating Engines

Renewables and Storage

- Indiana Wind
- Utility-Scale single-axis tracking solar
- 4-Hour Battery Storage

Figure 5.10 | Modeled Resources in the 2019 IRP

Capital costs were developed using a combination of publicly available data sources and proprietary, third-party vendor forecasts. Base capital costs were for most technologies using an average of the following data sources: NREL 2018 Annual Technology Baseline ("ATB"), IHS Markit, Wood Mackenzie, and Bloomberg New Energy Finance. These averages were benchmarked against other publicly available data sources including the Lazard Levelized Cost of Energy report Version 12.0 and NIPSCO's published summary of bid responses from their 2018 RFP. Confidential Attachment 5.5 contains confidential underlying assumptions for the build up of capital costs in the 2019 IRP.

IPL also conducted a sensitivity analysis that varied capital costs for wind, solar, and storage, which can be found in Section 7.

Figure 5.11 | Public Data Sources for Resource Capital Costs

National Renewable Energy Laboratory (NREL)

- 2018 Annual Technology Baseline (ATB)
- https://atb.nrel.gov/electricity/2018/

Lazard

- Levelized Cost of Energy Analysis, Version 12.0
- Levelized Cost of Storage Analysis, Version 4.0
- https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2018/

NIPSCO RFP Average Bid Prices

- NIPSCO 2018 Integrated Resource Plan
- 7-24-2018 Public Advisory Presentation
- https://www.nipsco.com/about-us/integrated-resource-plan

Figure 5.12 | Proprietary Third-Party Data Sources for Capital Costs

IHS Markit

- US wind capital cost and required price outlook: 2018
- US solar PV capital cost and required price outlook: 2018
- US battery energy storage system capital cost outlook (August 2018)
- 2018 Update of Rivalry Scenario
- Subscription Required: https://ihsmarkit.com/products/energy-outlooks-2040-power-gas-coal-renewables.html

Bloomberg New Energy Finance (BNEF)

- Energy Project Asset Valuation Model (EPVAL 8.8.4)
- 2H 2018 LCOE: Data Viewer
- Subscription Required: https://www.bnef.com

Wood Mackenzie

- North America Power & Renewables
- H1 2018 Long Term Outlook
- Subscription Required: https://www.woodmac.com/research/products/power-and-renewables/north-america-power-and-renewables-service/

5.2.1 Natural Gas

Simple-Cycle Combustion Turbine

For purposes of the IRP analysis, IPL assumed the incremental addition of a 100 MW CT in its expansion planning. Conventional frame CTs are a mature technology, widely used for peaking applications. The units are characterized by low capital costs, low non-fuel variable Operation and Maintenance Costs ("O&M"), modular designs and short construction lead times.

Combined Cycle Gas Turbine

The typical combined cycle installation consists of gas turbines discharging waste heat into a heat recovery steam generator ("HRSG"). The HRSG supplies steam that is expanded through a steam turbine cycle driving an electric generator. Combined cycle units have the distinct advantage of being the most efficient fossil-fueled process available.

Aeroderivative Turbine

Aeroderivative combustion turbines ("Aero CT") offer a fast-ramping, flexible peaking resource. Aero CTs have higher capital costs, but offer smaller, more modular design with faster dispatching parameters compared to a simple cycle CT.

Reciprocating Engines

Reciprocating engines are a mature technology that offer fast-ramping, firm dispatchable capacity with minimal water use and design flexibility due to their modular nature. Often used in CHP applications, engines can be sized as small as 10 kW and as large as 18 kW[14]. IPL modeled a "bank" of six (6) 18 MW engines with a total capacity of 108 MW. Reciprocating deployment is often seen in areas with high penetration of wind and solar, such as California, Texas, and states in the Southwest Power Pool (SPP)[15]. Fast-ramping, flexible resources like reciprocating engines could play a role in a high renewable grid.

Figure 5.13 contains cost and operations characteristic for new natural gas resources.

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[14] https://www.energy.gov/sites/prod/files/2016/09/f33/CHP-Recip%20Engines.pdf

[15] https://www.eia.gov/todayinenergy/detail.php?id=37972

Figure 5.13 | Natural Gas New Resource Assumptions

Unit	1x1 CCGT	Frame CT	Aero CT	Recip. Engine
Description	Combined Cycle	Combustion Turbine	Aeroderivative Turbine	6x0 18 MW Reciprocating Engines
COST				
Overnight Construction Cost [2023 COD] (2018$/kW)	$960	$749	$1,406	$1,305
Variable O&M (2018$/MWh)	$0.96	$0.48	$4.57	$6.03
Fixed O&M (2018$/kW-year)	$17.00	$15.60	$12.75	$5.84
CAPACITY AND OPERATION				
MISO ICAP (MW)	325.0	100.0	126.0	108.0
xEFORd %	5.370%	5.180%	5.180%	5.180%
MISO UCAP (MW)	307.5	94.8	119.5	102.4
Econ Max (MW)	325	100	42	18
Econ Min (MW)	145	62.5	21	8
Modeled Forced Outage %	5.8	10	2.03	3.3
Heat Rate at Max Load (Btu/kWh)	6,744	10,012	9,500	8,502
EMISSION RATES				
SO2	0.0006	0.001	0	0.001940921
NOx	0.0072	0.028	0.01	0.02512
CO2	119	119	119	119

5.3 Renewables and Storage

170 IAC 4-7-4(6) 170 IAC 4-7-4(31) 170 IAC 4-7-6(b)(3)(A)

IPL considered a wide range of renewable and storage applications for this IRP cycle. The three mature, commercially available technologies modeled were utility scale wind, solar, and front of the meter storage.

5.3.1 Wind

New Wind Resource Summary

- Modeled Generic Project Size: 50 MW
- Assumed location: Northwestern Indiana
- Annual Capacity Factor: 42%
- Capacity Credit: 7.8%
- Cost:
    - LCOE ~$31/MWh nominal with 80% PTC for 2021 COD
    - LCOE ~$50/MWh nominal with 0% PTC for 2025 COD

Production Profiles

The generic wind resource available for selection in the capacity expansion tool was an Indiana based wind farm located in northwestern Indiana. As discussed in a previous section, IPL has an existing PPA for Hoosier Wind Park in Benton County, IN. IPL has access to historical hourly data going back to 2009 for this wind farm. However, this wind farm is 10 years old, has a hub height of only 80 meters, and uses older turbines and technology. New wind farms are expected to have higher capacity factors. Therefore, IPL utilized other data sources for building the profile for the generic wind project.

IPL used the NREL Wind Toolkit and Wind Prospector[16] to build a generic wind profile for this IRP. We chose a midpoint capacity factor of 42% for Benton County to build the energy profile for a generic 50 MW project. NREL provides 5-minute simulated production data in MW based on the power curve of the wind site. IPL integrated the data to hourly data and scaled up the hourly generation for a 50 MW project. The result was four years of hourly simulated historical data for that wind farm location. Figure 5.14 contains an example of a month of scaled hourly data from NREL for May 2009. Figure 5.15 shows the process flow for data being incorporated in the PowerSimm model.

PowerSimm uses the scaled historical data in conjunction with a forecasted monthly energy production target to simulate a wind profile through time. Through PowerSimm's weather simulation, the shape will be different in each iteration and will scale to the mean output entered monthly.

A sensitivity analysis on the capacity factor was conducted and results can be found in Section 7.4.3.

[16] NREL Wind Prospector. Retrieved from: https://maps.nrel.gov/wind-prospector/?aL=p7FOkl%255Bv%255D%3Dt&bL=clight&cE=0&lR=0&mC=40.21244%2C-91.625976&zL=4

Figure 5.14 | Example NREL Wind Toolkit Scaled Hourly Data, May 2009

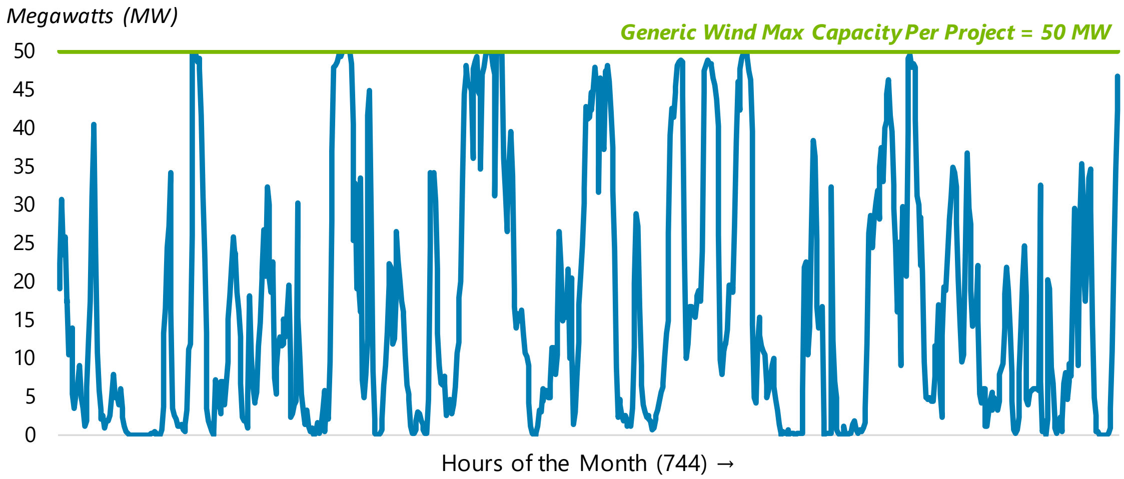


Figure 5.15 | Process Data Flow for Developing Generic Wind Profiles

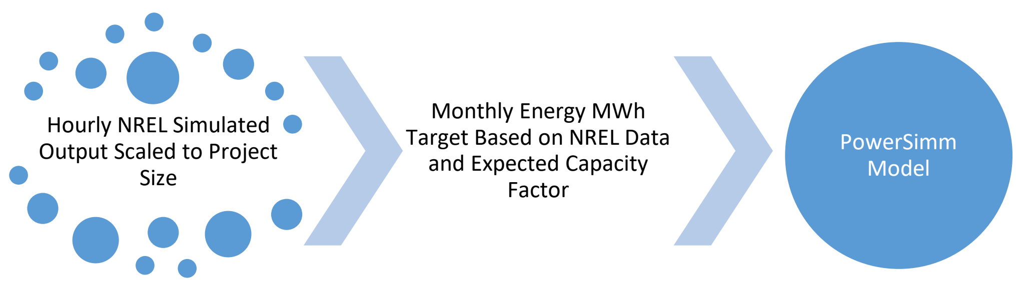
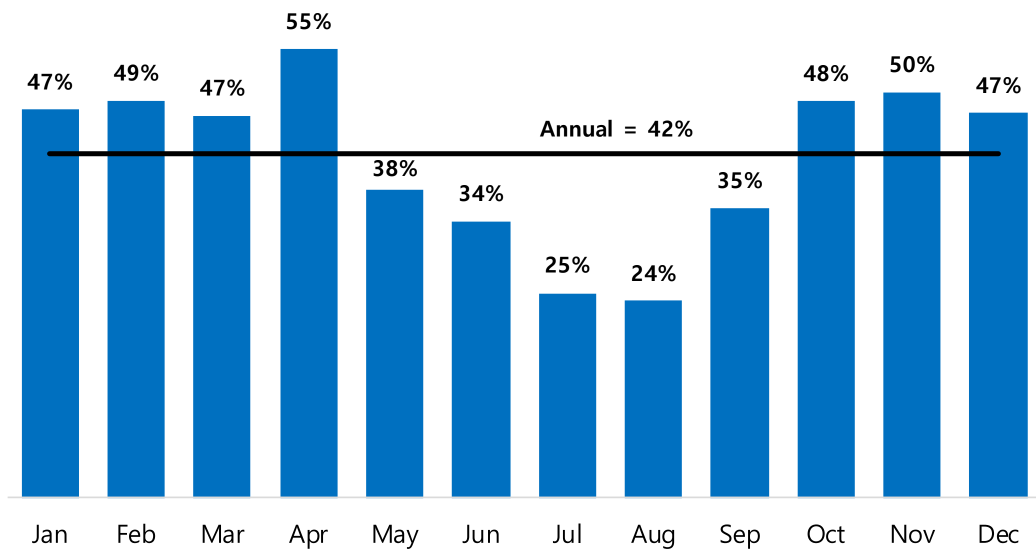


Figure 5.16 | Generic New Wind Monthly Capacity Factors



Capacity Credit

The capacity credit was modeled at 7.8% ELCC for Zone 6 throughout the planning study based on the PY 2019/2020 Wind Capacity Credit report published by MISO in December 2018[17]. MISO conducts a two-phase Effective Load Carrying Capability ("ELCC") study annually to assess the capacity credit of wind. The first phase includes a probabilistic assessment of system-wide wind in MISO, and the second phase is a deterministic allocation of the system-wide capacity to individual projects based on historical performance and location.

New wind projects with no commercial operation meter data receive the system-wide MISO ELCC (15.6% for PY 19/20) and will receive the unit specific allocated UCAP in all subsequent years. There is uncertainty regarding what capacity credit a new Indiana wind project would receive after the first year. Newer turbines with higher hub heights could be allocated a higher capacity credit relative to older vintage wind projects. To be conservative, IPL is modeling new wind with a 7.8% capacity credit. This is higher than the three-year average at Hoosier Wind Park and is the best available information at the time of this IRP modeling exercise. Any risk or opportunity created by a potential mismatch in planning capacity credit and realized capacity credit can be mitigated on a yearly basis through active position management and through the capacity tracker.

[17] https://cdn.misoenergy.org/2019%20Wind%20and%20Solar%20Capacity%20Credit%20Report303063.pdf

Capital and O&M Costs

Base capital costs for new wind projects were based on a blend of capital cost projections from NREL, IHS Markit, Wood Mackenzie, and Bloomberg New Energy Finance. The Production Tax Credit (PTC) is a major driver of value for wind projects, and Figure 5.17 contains assumptions for how the PTC was modeled in the 2019 IRP. IPL assumed that new wind met the 5% safe harbor rules to be eligible for 100% in 2020, stepping down to 0% by 2024. In the PowerSimm capacity expansion module, capital costs entered were adjusted down for the value of the PTC rather than entered as a credit to variable O&M. As Figure 5.18 shows, each 20% reduction in the PTC increases the LCOE by about $3.50/MWh in real terms, and the PTC can reduce overall costs by as much as 60%.

All new projects in the IRP are modeled as 100% IPL-owned assets, and the revenue requirement calculation reflects traditional rate recovery assuming a rate case every year. Tax equity financing would could be required for any new IPL-owned wind project with PTC eligibility, and the actual ownership level, tax implications, and final net costs would be fully modeled at the time of a regulatory filing for an actual project. Additional capital cost sensitivities were conducted to capture some of the uncertainty around capital costs. That analysis is described in Section 7.4.1.

Figure 5.17 | Production Tax Credit Assumptions for New Wind in 2019 IRP

	2020	2021	2022	2023	2024
Wind PTC Assumption	**100%**	**80%**	**60%**	**40%**	**0%**
Overnight Capital Cost (2018$/kW)	$1,423	$1,406	$1,393	$1,382	$1,372
PTC-Adjusted Capital Cost (2018$/kW)	$633	$779	$925	$1,071	$1,372
LCOE - No PTC (2018$/MWh)	$44.57	$43.99	$43.55	$43.17	$42.82
LCOE with PTC (2018$/MWh)	$25.34	$28.75	$32.18	$35.63	$42.82

Figure 5.18 | New Wind Capital Cost (2018$/kW)

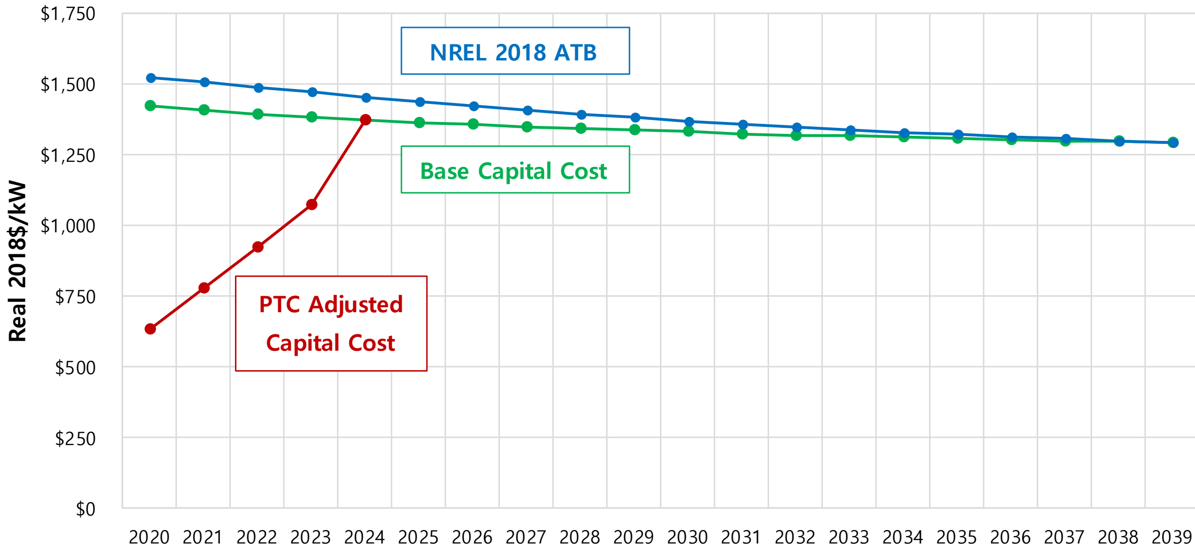
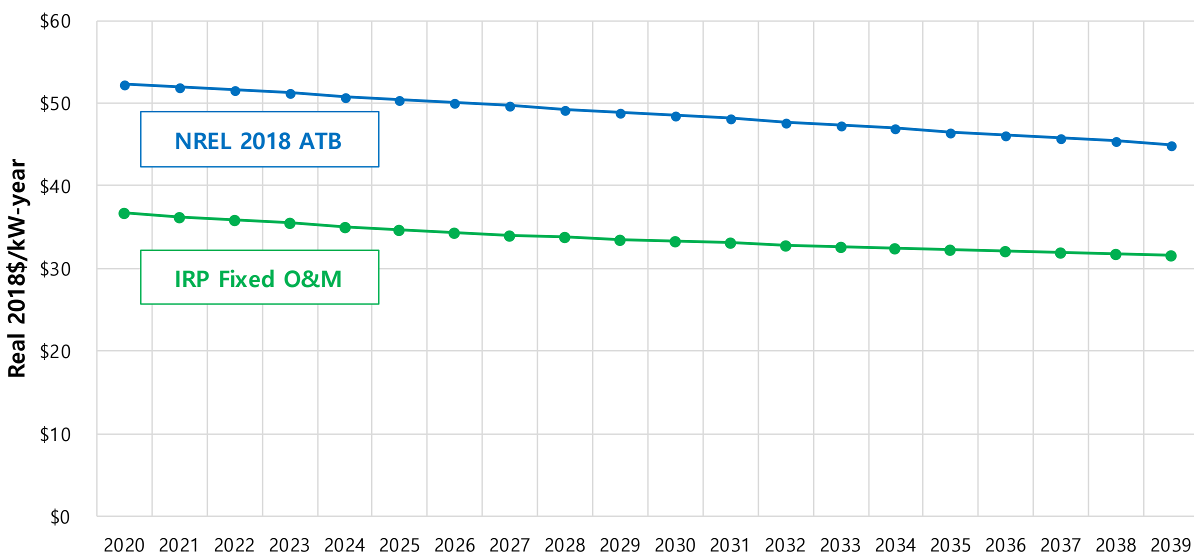


Figure 5.19 | New Wind Fixed O&M ($/kW-year)



5.3.2 Solar

New Solar Resource Summary

• Modeled Generic Project Size: 25 MW
• Assumed location: Central Indiana
• Annual Capacity Factor: 23%
• Capacity Credit: Declining ELCC from 63% in 2020 to 23% in 2039
• Cost:
    • LCOE ~$35/MWh nominal with 100% ITC for 2023 COD
    • LCOE ~$45/MWh nominal with 10% ITC for 2025 COD

Capacity Factor and Profile

IPL utilized hourly historical production from IPL-contracted REP solar projects to build production profiles for generic new solar projects. All generic new solar was assumed to be utility-scale, single-axis tracking solar located in central Indiana.

Figure 5.20 contains the process data flow for developing generic solar profiles. The process is very similar to creating wind profiles, with three years of historical data and monthly energy targets scaled to the generic project size entered in PowerSimm. Solar profiles are simulated based on this historical data and scaled to the monthly energy that is directly related to the capacity factor assumption.

Figure 5.20 | Process Data Flow for Developing Generic Solar Profiles

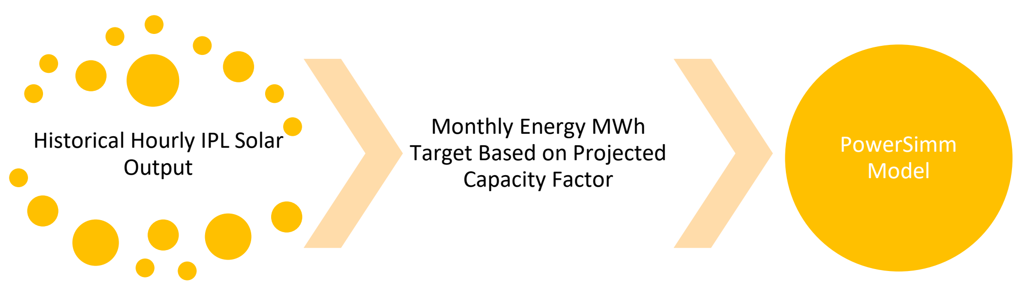
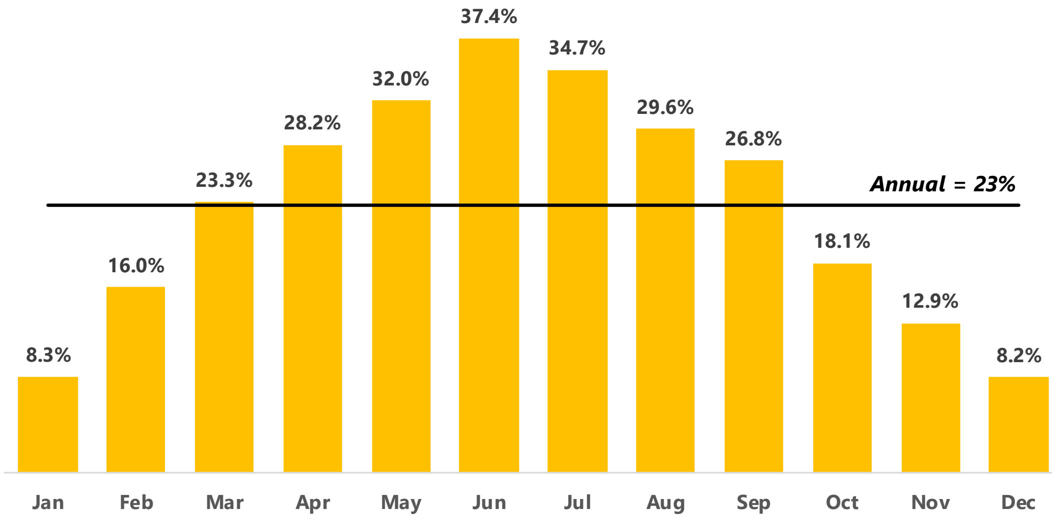


Figure 5.21 shows the monthly capacity factor assumption used for new solar projects. The annual capacity factor assumed was 23%, with monthly capacity factors ranging from 8% in winter to above 35% in the summer.

Figure 5.21 | IRP Generic Single-Axis Tracking Solar, Monthly Capacity Factor



Capacity Credit

Solar production occurs during the day, which provides capacity contribution during some of the highest load hours in the summer. MISO's Resource Adequacy Business Practice Manual[18] (BPM-011) contains the following language for determining solar capacity credit:

> Solar photovoltaic (PV) resources will have their annual UCAP value determined based on the 3 year historical average output of the resource for hours ending 15, 16, and 17 EST for the most recent Summer months (June, July, and August)… Resources with less than 30 days of metered values would receive the class average of 50% for its Initial Planning Year.

By default, new solar resources in MISO receive a 50% capacity credit for the first year, and capacity credit in subsequent years will be based on average hourly production for each hour between 2pm and 5pm (Hours ending 13-17) EST. Figure 5.22 contains a three-year historical average output of IPL tracking solar by hour. The capacity factor for HE 15-17 for the period of 2016-2018 was approximately 63%. This was used as the capacity credit for the first year of the IRP study (2020).

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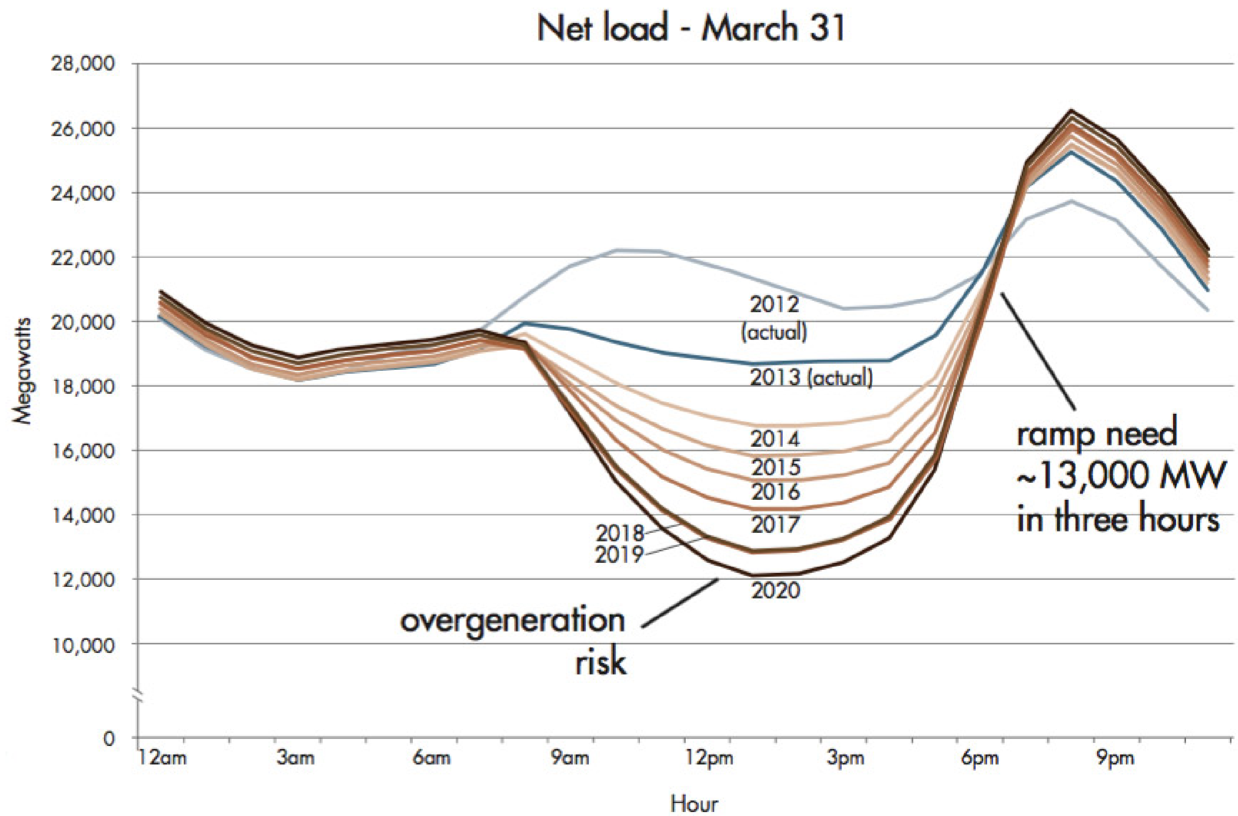
[18] https://www.misoenergy.org/planning/resource-adequacy

Figure 5.22 | IPL Single-Axis Tracking Average Capacity Factor, 2016 – 2018

HE	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	0%	0%	0%	2%	1%	0%	0%	0%	0%	0%
7	0%	0%	1%	4%	9%	21%	17%	5%	1%	0%	0%	0%
8	0%	0%	7%	27%	31%	53%	46%	28%	17%	6%	1%	0%
9	3%	11%	33%	51%	51%	70%	63%	50%	47%	30%	13%	3%
10	16%	31%	52%	59%	62%	76%	71%	62%	62%	45%	32%	15%
11	25%	41%	56%	62%	66%	76%	70%	66%	65%	50%	38%	25%
12	25%	47%	60%	66%	68%	75%	72%	67%	66%	50%	40%	27%
13	26%	49%	59%	67%	68%	73%	69%	68%	65%	49%	38%	28%
14	26%	47%	59%	66%	69%	71%	69%	66%	64%	47%	39%	28%
15	26%	45%	56%	63%	66%	**69%**	**65%**	**66%**	63%	45%	38%	26%
16	23%	41%	52%	57%	62%	**68%**	**64%**	**60%**	59%	42%	33%	22%
17	13%	30%	46%	52%	61%	**67%**	**62%**	**54%**	52%	29%	12%	7%
18	2%	10%	27%	37%	53%	60%	55%	44%	29%	7%	0%	0%
19	0%	0%	6%	12%	32%	37%	34%	18%	5%	0%	0%	0%
20	0%	0%	0%	1%	9%	8%	8%	2%	0%	0%	0%	0%
21	0%	0%	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

For future years, the capacity credit was decreased in accordance with information provided by MISO as part of the Renewable Integration Impact Assessment ("RIIA") study. It is helpful to think of solar's capacity contribution in terms of net load. Net load is defined as the load not being served by renewables, which is simply calculated as the actual load minus renewable production for each hour of the day. As more solar is added to the system, the peak net load hour shifts to later in the day when solar production starts to drop off. This is often referred to as the "duck curve" problem observed by regions like California that have more solar on the system (the duck being the outlined shape in the new net load curve). Figure 5.23 shows the original net load chart from the California ISO (CAISO).

Figure 5.23 | Original California ISO (CAISO) Duck Curve Chart[19]



Through MISO's RIIA study[20], MISO provided an estimated ELCC curve at different installed amounts of solar by examining the capacity credit at increasing capacity levels. Figure 5.24 contains the curve for wind and solar as well as the equations used by MISO to calculate how much solar and wind need to be installed to meet the RIIA inflection points for renewable penetration.

To calculate the ELCC by year for the IRP, IPL used annual forecasted installed solar in MISO from Wood Mackenzie's H1 2018 Long Term Outlook. Figure 5.25 contains the annual capacity credit used in modeling for the IRP. Different capacity credit was given to fixed tilt and tracking solar, which is consistent with a more detailed ELCC study[21] from MISO and validated by IPL experience with data from existing solar.

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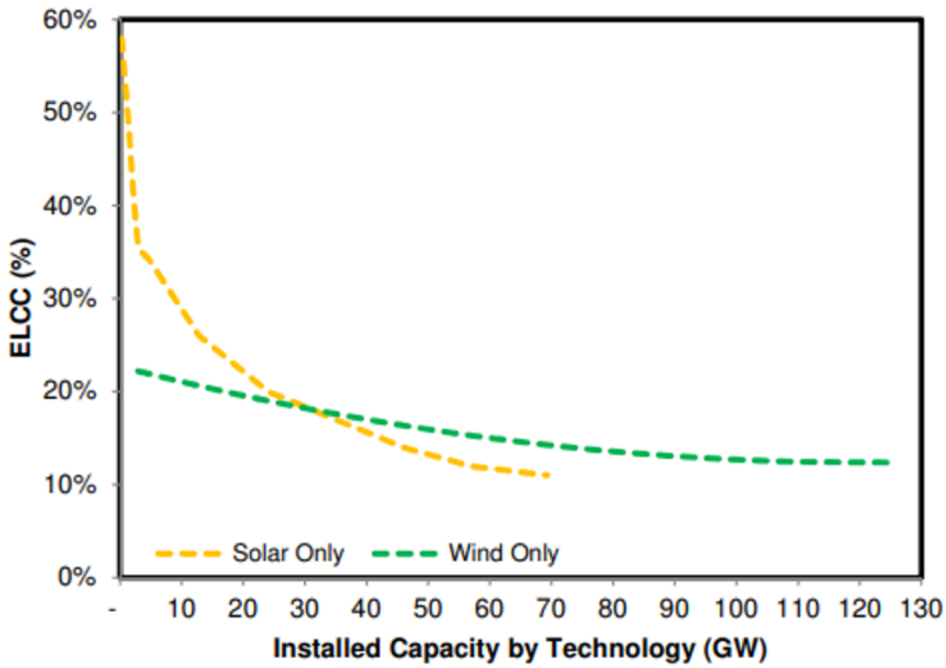
[19] https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

[20] MISO RIIA Assumptions Document, Version 6. https://cdn.misoenergy.org/RIIA%20Assumptions%20Doc_v6301579.pdf

[21] B. Heath and A. L. Figueroa-Acevedo, "Potential Contribution of Wind and Solar Generation in MISO System," in IEEE International Conference on Probabilistic Methods Applied to Power Systems, Boise, ID, 2018.

Figure 5.24 | MISO RIIA Assumptions: Solar ELCC %



These graphs were approximated by the *siting- and fuel-mix specific* functions in Equation 1, where UCAP is unforced capacity and ICAP is installed capacity.

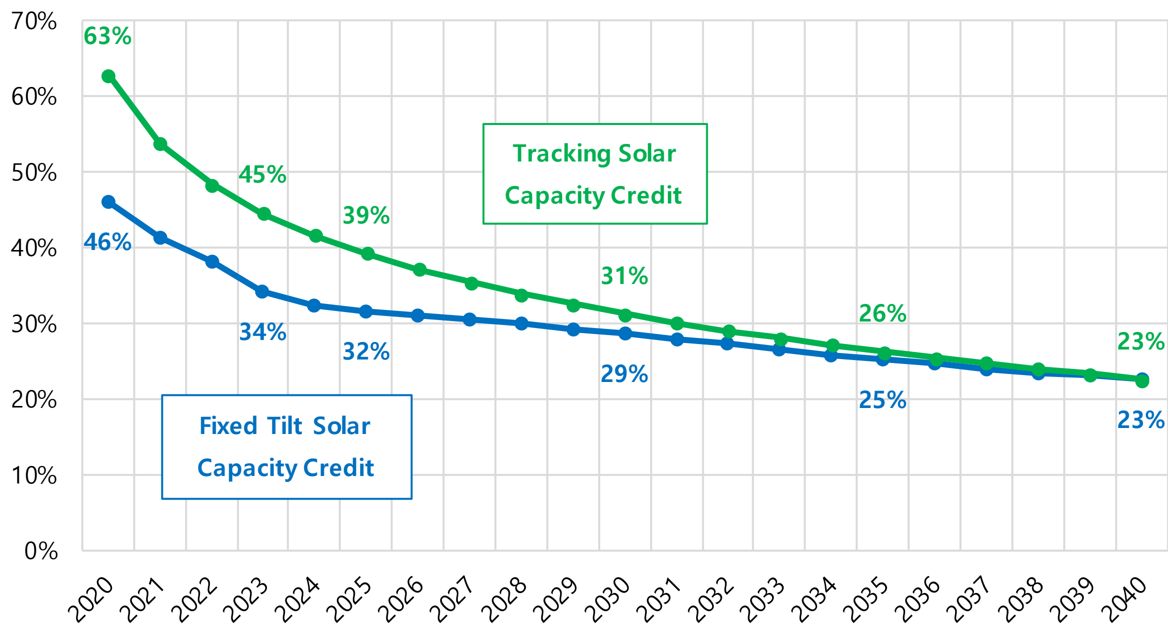
Equation 1 Approximate ELCC functions for wind and solar

$$\text{Wind } UCAP = (-0.3\ln(ICAP) + 0.26) * ICAP$$

$$\text{Solar } UCAP = (-0.07\ln(ICAP) + 0.42) * ICAP$$

Source: MISO

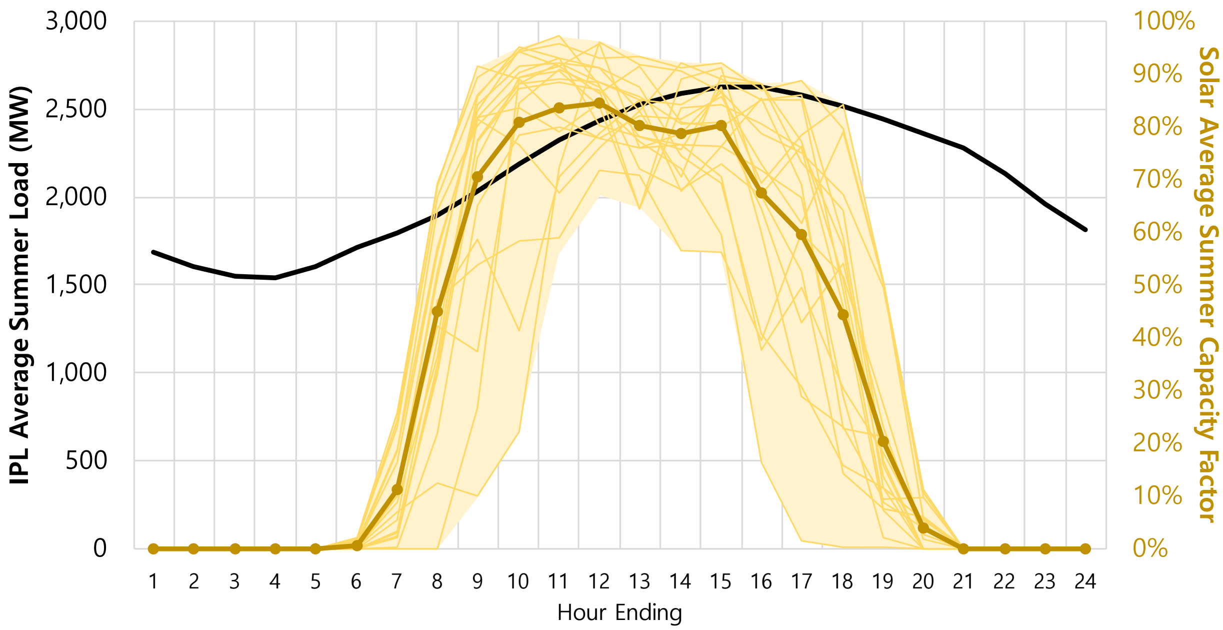
Figure 5.25 | Modeled Annual Solar Capacity Credit for 2019 IRP



To validate these solar capacity credit assumptions, IPL evaluated the coincidence of solar production with load for the top 20 peak summer and winter load days over the past three years for our own system.

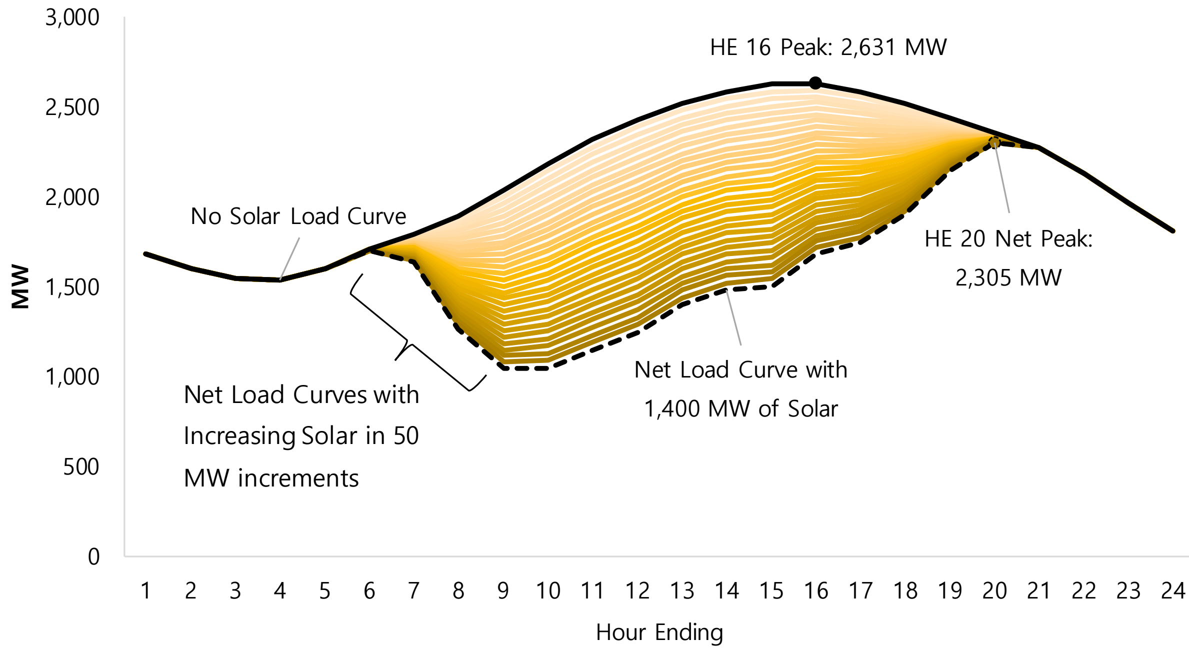
Figure 5.26 shows the average IPL load profile by hour of day for the top 20 summer days from 2016 to 2018 as well as the hourly capacity factor of IPL tracking solar for the same days. The chart shows that on average solar production is limited between 7am and 9pm EST, and there is ample production across the highest load hours (2pm to 5pm). IPL's average peak hour is HE 16 for this data sample, and IPL tracking solar averaged production of 67% of nameplate capacity during that hour for the same data sample.

Figure 5.26 | IPL Load and Solar Profile: Top 20 Peak <u>Summer</u> Days, 2016 - 2018



To estimate the impact of increasing solar on IPL's net load curve, we scaled up the typical summer profile in increments of 50 MW up to 1,400 MW of solar. Figure 5.27 shows how the net peak load for IPL shifts from HE 16 (3-4pm) to HE 20 (7-8pm) as the amount of solar increases on the system.

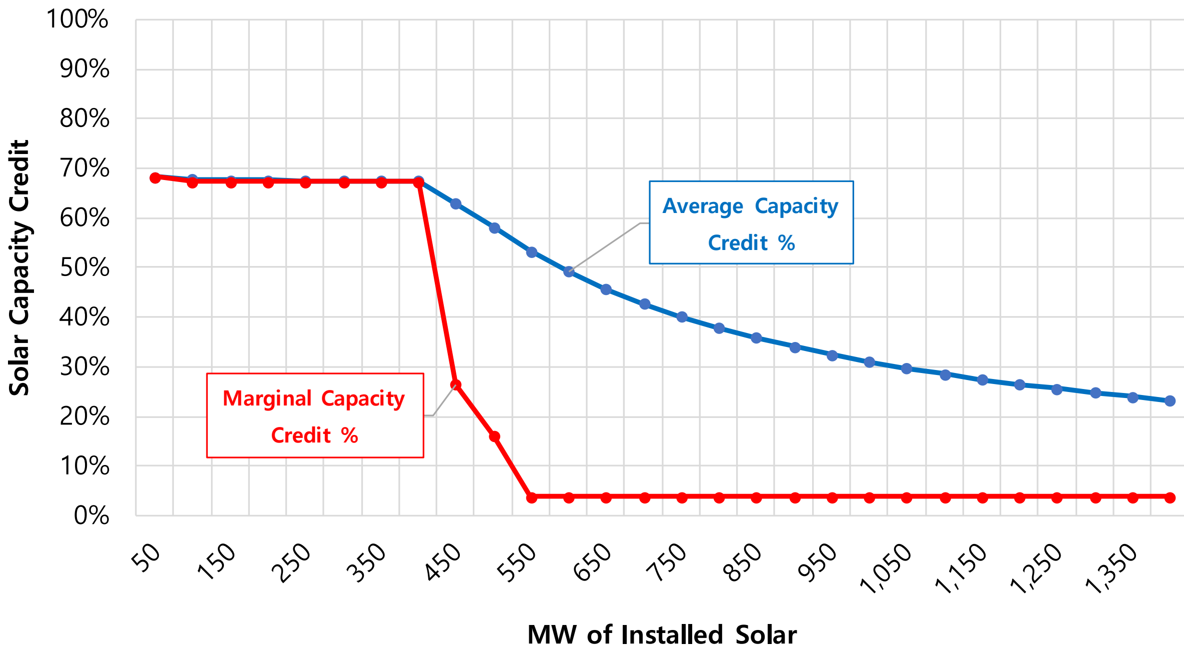
Figure 5.27 | IPL Net Load Curve with Increasing Solar Levels



From this data, we can calculate the average and marginal capacity credit for each level of solar installed on the system. The average capacity credit is the cumulative peak load reduction divided by the cumulative level of installed solar assumed. The marginal capacity credit is a calculation of the incremental peak load reduction for each incremental addition of solar. The steep reduction in marginal capacity credit past 400 MW is a result of the peak net load hour shifting later into the evening (HE 20) where solar production is minimal. The data shows that for each 50 MW increase in solar on IPL's system only contributes 2 MW of capacity past 500 MW of installed solar. Figure 5.28 shows the average and marginal capacity credit for each increment of solar installed from 50 MW to 1400 MW.

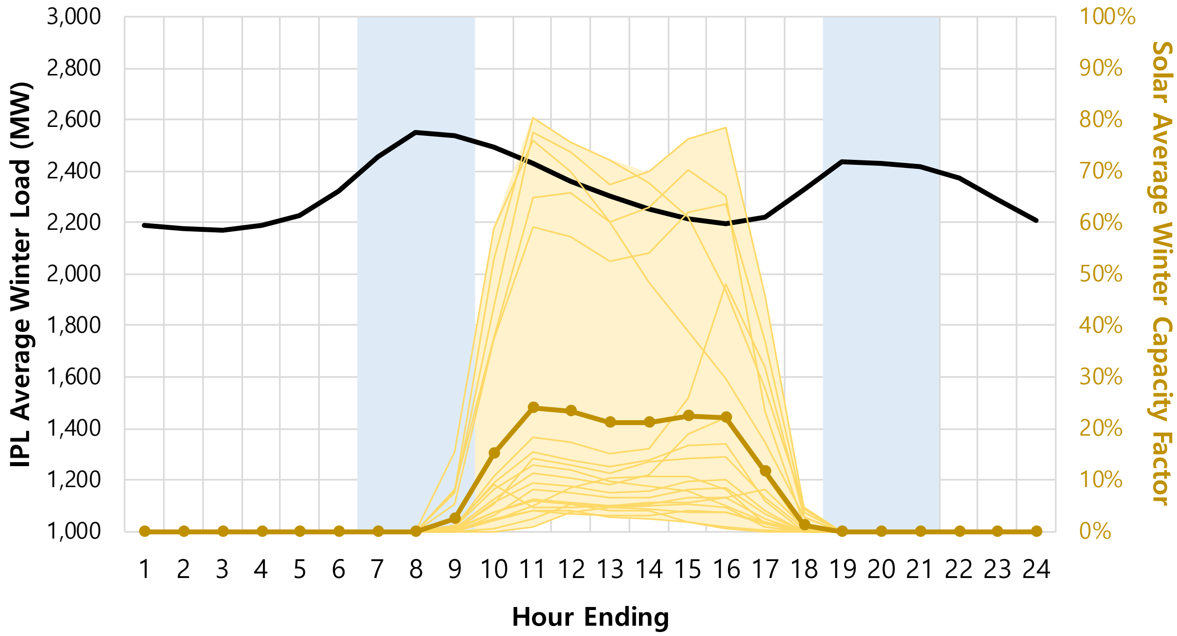
This analysis should not be viewed as a final say on the potential solar capacity on IPL's system or in our portfolio. It was conducted to provide a secondary analysis of future solar capacity accreditation using our own load and solar data and provides a useful framework to build upon as more solar is installed in Indiana and in the MISO region.

Figure 5.28 | Estimated Solar Capacity Credit on IPL System with Increasing Solar Levels



We also evaluated the top 20 peak winter days from the past three years (2016 – 2018). Figure 5.29 shows the average load by hour for those peak winter days as well as the tracking solar production for the same days. Solar production averages about a quarter of the production compared to summer. Additionally, solar production has no coincidence with the morning and evening peaks, providing no capacity contribution in winter as a standalone resource.

Figure 5.29 | IPL Load and Solar Profile: Top 20 Peak Winter Days, 2016 - 2018



Overall, the IPL load and solar data validates the assumptions used for this IRP for the annual solar capacity credit. **There is a lot of uncertainty going forward regarding this issue, and IPL will closely study this through time.** The pace of solar build in MISO, changing load patterns, and new MISO market rules could change solar's capacity accreditation in the future. Additionally, there are some actions IPL directly take to improve the capacity contribution of solar. Some examples include battery storage applications, new rate design to incentivize load to shift to midday, demand response programs, electric vehicle charging programs, and selection of geographically diverse solar locations.

Capital and O&M Costs

Base capital costs for new wind projects were based on a blend of capital cost projections from NREL, IHS Markit, Wood Mackenzie, and Bloomberg New Energy Finance. Figure 5.30 contains assumptions for how the Investment Tax Credit (ITC) was modeled in the 2019 IRP. IPL assumed that new solar met the 5% safe harbor rules to be eligible for 100% through 2023, stepping down to 10% by 2024 and remaining at that level through the end of the study. Similar to PTC treatment for wind, the capital cost for solar was adjusted down for the ITC in PowerSimm for capacity expansion. As Figure 5.30 shows, the 30% ITC lowers the LCOE by $13-15/MWh and is a significant driver of value for solar.

All new projects in the IRP are modeled as 100% IPL-owned assets, the revenue requirement calculation reflects traditional rate recovery assuming a rate case every year. Tax equity financing could be required for any new IPL-owned solar project with ITC eligibility, and the actual ownership level, tax implications, and final net costs would be fully modeled at the time of a regulatory filing for an actual project. Additional capital cost sensitivities were conducted to capture some of the uncertainty around capital costs. That analysis is described in Section 7.4.1.

Figure 5.30 | Solar Investment Tax Credit (ITC) Assumptions

	2020	2021	2022	2023	2024
Solar ITC Assumption	**30%**	**30%**	**30%**	**30%**	**10%**
Overnight Capital Cost (2018$/kW)	$1,099	$1,034	$989	$929	$911
ITC-Adjusted Capital Cost (2018$/kW)	$724	$682	$652	$612	$808
LCOE - No ITC (2018$/MWh)	$53.36	$50.12	$47.87	$44.96	$43.91
LCOE with ITC (2018$/MWh)	$36.92	$34.74	$33.22	$31.26	$39.45

Figure 5.31 | New Solar Capital Costs (2018$/kW$_{AC}$)

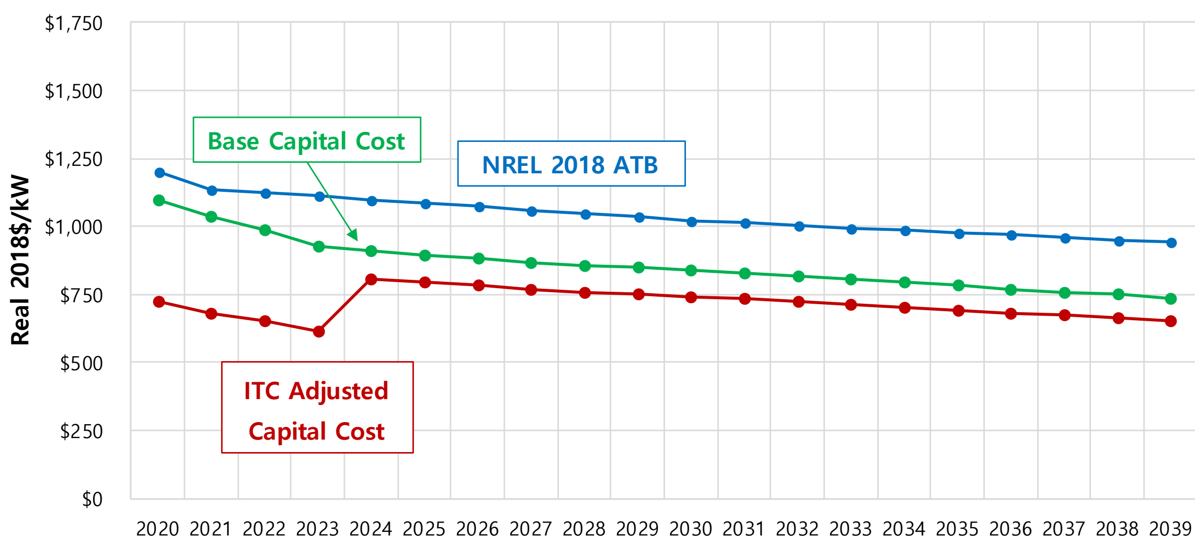
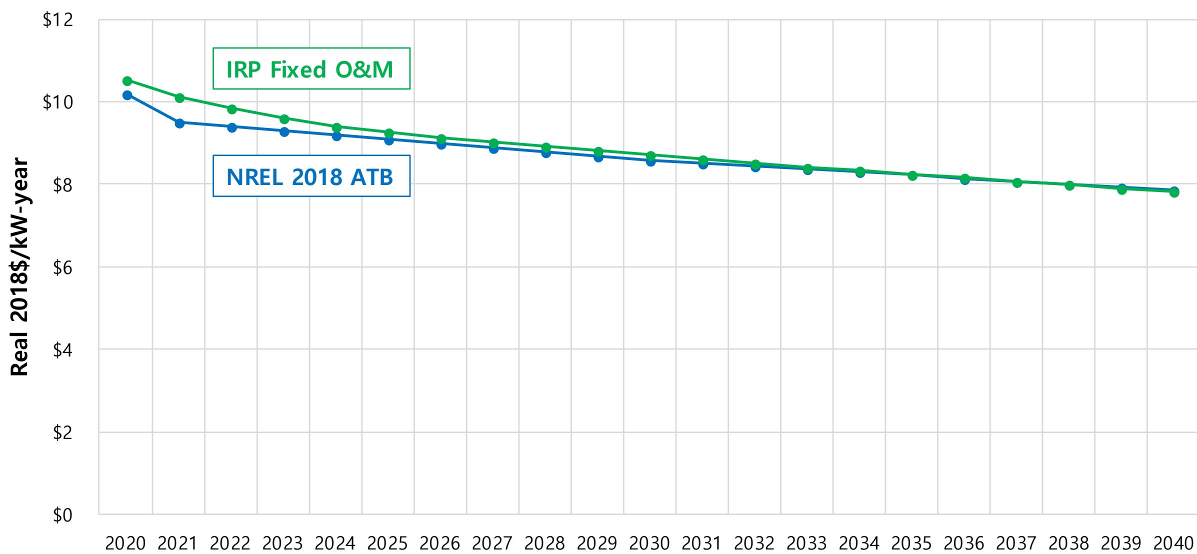


Figure 5.32 | New Solar Fixed O&M (2018$/kW$_{AC}$-year)



5.3.3 Storage

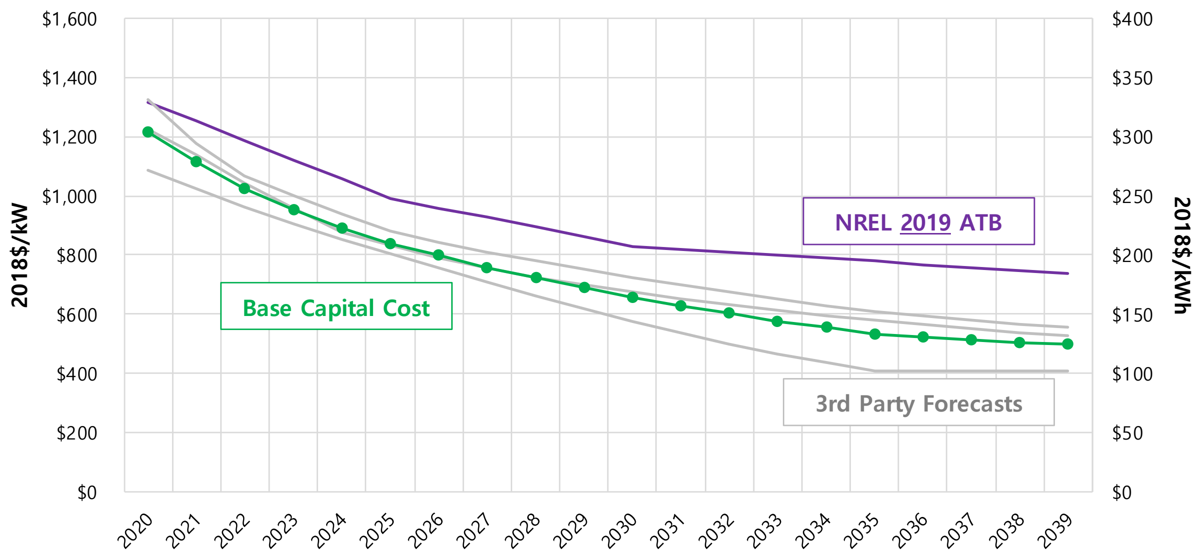
IPL included an energy arbitrage and capacity 4-hour battery storage resource in the 2019 IRP. Storage was optimized using the BatterySimm module in PowerSimm. The storage resource modeled was a **20 MW, 80 MWh** lithium ion battery storage project capable of charging and discharging subject to a set of unit constraints. Figure 5.33 contains a summary of cost and operating characteristics of new storage in the 2019 IRP.

Figure 5.33 | IRP Assumptions for New Battery Storage Projects

Unit	STORAGE
Description	4-hour lithium ion battery storage project
COST	
Overnight Construction Cost [2023 COD] (2018$/kW)	$954
Variable O&M (2018$/MWh)	$4.53
Fixed O&M (2018$/kW-year)	$19.02
CAPACITY	
MISO ICAP (MW)	20.0
xEFORd %	5.0%
MISO UCAP (MW)	19.00
Energy per Project (MWh)	80.00
OPERATIONAL	
Round Trip Efficiency %	88%
Min Storage Limit (MWh)	4.0
Max Storage Limit (MWh)	76.0
Charge/Discharge Limit (MW/hour)	20.0

Figure 5.34 shows the trend in capital cost for storage used in the model compared to NREL and other confidential third-party vendors. At the time capital costs were developed for this IRP, the NREL 2018 ATB was available, and that release only contained data for 8-hour storage, so it was not used. In the NREL 2019 ATB, NREL did update storage cost estimates for 4-hour storage projects. This is shown in Figure 5.34 in purple. As the figure shows, storage costs are expected to decline through time as a faster pace than any other supply-side resource included in this IRP.

Figure 5.34 | 4-Hour Storage Capital Cost (2018$/kW)



5.4 Summary of Supply-Side Resources

Figure 5.35 contains a list of modeled supply-side resources in the 2019 IRP as well as a description of types of resources that were screened out for this IRP.

Figure 5.35 | Supply-Side Resource Summary Table

Resource Type	Description	Included in 2019 IRP	Notes
Natural Gas	1x1 Combined Cycle	Yes	Section 5.2.1
Natural Gas	Simple Cycle Combustion Turbine	Yes	Section 5.2.1
Natural Gas	Aeroderivative Turbine	Yes	Section 5.2.1
Natural Gas	Reciprocating Engines	Yes	Section 5.2.1

Natural Gas	Coal to Gas conversion for Pete 1 and 2	No	Conversion of Pete 1 and 2 was not considered for this IRP. The age of the units and the location were the two primary limiting factors. Pete 1 and 2 are 52 and 49 years old, respectively, and are nearing age-based retirement dates. Planning, engineering, procurement, and actual conversion work would take several years while the units incur millions of dollars in maintenance and overhaul costs. Additionally, one of the most important factors that led IPL to convert the Harding Street steam units to gas was their location on the IPL 138 kV distribution system. The Harding Street units play a critical role in maintaining reliability on the IPL distribution system. Due to the location of Petersburg, conversion of Pete 1 and 2 would not provide the same reliability benefits. Lastly, conversion of Pete 1 and 2 to natural gas would cause IPL to have nearly half of our capacity tied to natural gas steam units with pending retirement dates in the next decade.
Coal	New Coal	No	Screened out for permitting constraints, cost
Nuclear	New nuclear	No	Screened out for cost and size
Renewable	Utility-scale land-based wind	Yes	Section 5.3.1
Renewable	Utility-scale, single-axis tracking solar	Yes	Section 5.3.2
Renewable	Utility-scale fixed tilt solar	No	Utility-scale tracking solar provides more energy, greater capacity credit, and with minimal to no cost premium compared to fixed tilt projects, residential solar, and commercial solar. Since the model is optimizing on a "profit maximization" basis per project, it will always choose single-axis tracking solar. IPL will evaluate all solar technologies as part of an ongoing process for commercial, transmission, distribution, and portfolio fit aspects.
Renewable	Residential and/or commercial solar	No	
Storage	4-Hour Battery Storage	Yes	Section 5.3.3

5.5 Demand Side Resource Options

170 IAC 4-7-4(6) 170 IAC 4-7-4(31) 170 IAC 4-7-6(a)(6) 170 IAC 4-7-6(b)(2)(A)

IPL's demand side management ("DSM") programs are comprised of both energy efficiency and demand response analogous to energy and peak requirements. Energy Efficiency is reduced energy use for a comparable or imposed level of energy service (as measured in kWh), and Demand Response is a reduction in demand for limited intervals of time, such as during peak electricity usage or emergency conditions (as measured in kW).

5.5.1 IPL's DSM Guiding Principles

170 IAC 4-7-6(b)(2)(F)

IPL has continuously offered DSM programs to benefit customers and optimize demand side resources for over twenty-five years. Despite the changes in policy that eliminated the state energy efficiency standard and the Energizing Indiana statewide program, IPL has remained dedicated to offering DSM programs. The current level is approximately equal to prior EE levels. IPL developed this list of guiding principles that characterize DSM offerings.

IPL's guiding principles shape future DSM program offerings:

- DSM programs are inclusive for customers in all rate classes;
- DSM programs are appropriate for our market and customer base;
- DSM programs are cost-effective;
- DSM programs modify customer behavior; and
- DSM programs should provide continuity from year to year.

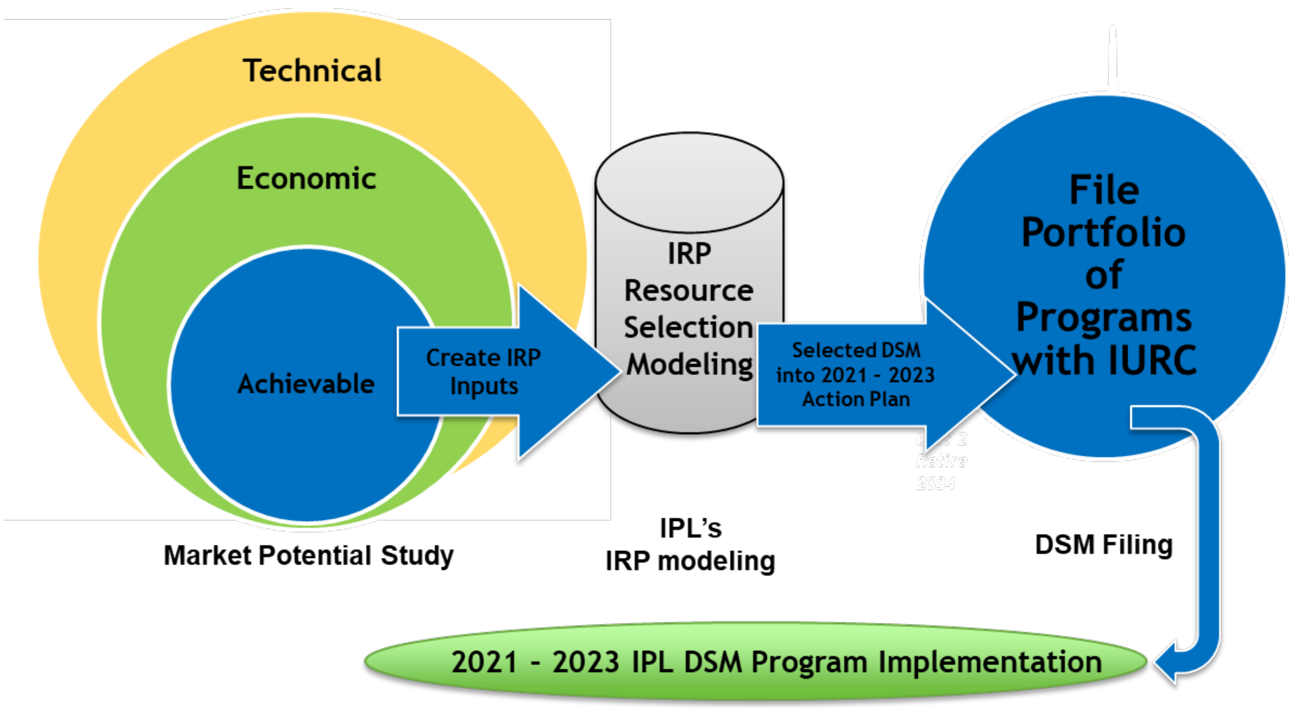
The Company expects to continue to propose and deliver additional cost-effective programs consistent with the IURC IRP and CPCN rules for demand side management options. The specific programs to be delivered will be identified and proposed in subsequent IPL DSM plans to be filed with the IURC.

5.5.2 DSM Planning Overview

170 IAC 4-7-6(b)(2)(C)

Figure 5.36 below illustrates the stages of IPL's DSM planning process. The objective of this process is to identify IPL's opportunities to provide DSM for the 20-year IRP planning period in a manner that aligns with direction provided by the IURC and that is consistent with IRP rules. DSM opportunities identified in the IRP process will be used as the starting point for development of a cost-effective 2021 – 2023 DSM Action Plan for consideration and approval by the IURC. This Action Plan will be consistent with Ind. Code Section 8-1-8.5-10 ("Section 10") which defines energy efficiency goals as all energy efficiency produced by cost effectives plans that are 1) reasonably achievable; 2) consistent with the utility's IRP; 3) designed to achieve an optimal balance of energy resources in the utility's service territory.

Figure 5.36 | Overview of DSM Process



IPL initiated the current DSM planning process by contracting with GDS Associates, Inc. (GDS) to complete a Market Potential Study (MPS) and End-Use Analysis. GDS is an engineering and consulting firm with a practice that includes energy efficiency planning for utilities. The MPS determined an achievable level of DSM in IPL's service territory by estimating customer adoption rates for a comprehensive list of DSM measures. The MPS helped to ensure that the level of DSM that is optimized within the IRP is "reasonably achievable" as discussed in more detail in part 2 of this section.

Per IURC IRP rule 170 IAC 4-7-8(c)(4), demand-side resources should be modeled on a consistent and comparable basis with supply-side resources. To accomplish this, IPL took the Realistic Achievable Potential ("RAP") results from the MPS and created IRP model inputs (stage 2 in Figure 5.36) with a load shape and levelized costs similar to a supply-side resource. The RAP results were then divided into eight "bundles", that each provided a 0.25% reduction in IPL load. The bundles were rank ordered starting with the most cost-effective measure. This bundling approach is discussed in more detail in Section 5.4.3.

The results from the IRP modeling will be used to inform the DSM Action Plan for the 2021-2023 period. DSM measures from the bundles will be developed into deliverable programs and a plan that will be filed with the IURC for its consideration and approval. The DSM modeling process and DSM Action Plan is discussed in more detail in Section 5.4.4 and 9.1.1, respectively, of this section.

IPL DSM Program Year 2020

Currently, IPL is delivering energy efficiency programs pursuant to the IURC Order received in Cause No. 44945. This Order that approved IPL's DSM Plan, which includes DSM and Energy Efficiency ("EE") programs for the 2018-2020 period. In program year 2020, IPL is planning to achieve approximately 140,000 MWh in energy efficiency savings or 1% of electric sales. Since IPL already has authority to deliver programs in 2020 at a level consistent with the 2016 IRP, the 2020 energy efficiency savings are already reflected as a reduction to the 2020 load forecast in this IRP.

DSM Stakeholder Engagement

IPL has maintained a strong collaborative relationship with its stakeholders throughout the DSM planning and IRP process making all DSM planning documents available to stakeholders with confidentiality agreements. Additionally, IPL has welcomed stakeholder input into the process and made an effort to incorporate stakeholder ideas into its methods, e.g. decrement bundling methodology described later in this report. Throughout the MPS process, IPL hosted technical meetings with stakeholders to share findings and to receive feedback during the DSM planning process. A list of stakeholder technical meeting dates and topics are as follows:

- 2019 Market Potential Study (MPS) & End Use Analysis Meeting – November 27, 2018
- MPS Models Review Meeting – April 1, 2019
- Between January and May 2019, IPL hosted bi-weekly meetings with GDS Associates and the IPL DSM OSB members.
- IRP Technical Workshop (prior to Public Meeting #2) – March 21, 2019
- IRP Technical Workshop (prior to Public Meeting #3) – May 9, 2019
- IRP Technical Workshop (prior to Public Meeting #4) – September 26, 2019

Opt-Out Customers

Senate Enrolled Act 340 provides the option for C&I customers that have a load greater than 1 MW to opt-out of participation in IPL's DSM programs. The MPS analysis that GDS completed considered the reduction in eligible load that was available to participate in IPL sponsored DSM programs. At the time the analysis was completed, 117 of IPL's largest customers representing approximately 23% of IPL's total sales had opted out of participation in IPL's DSM programs. These customers and their associated load have been excluded from the MPS analysis.

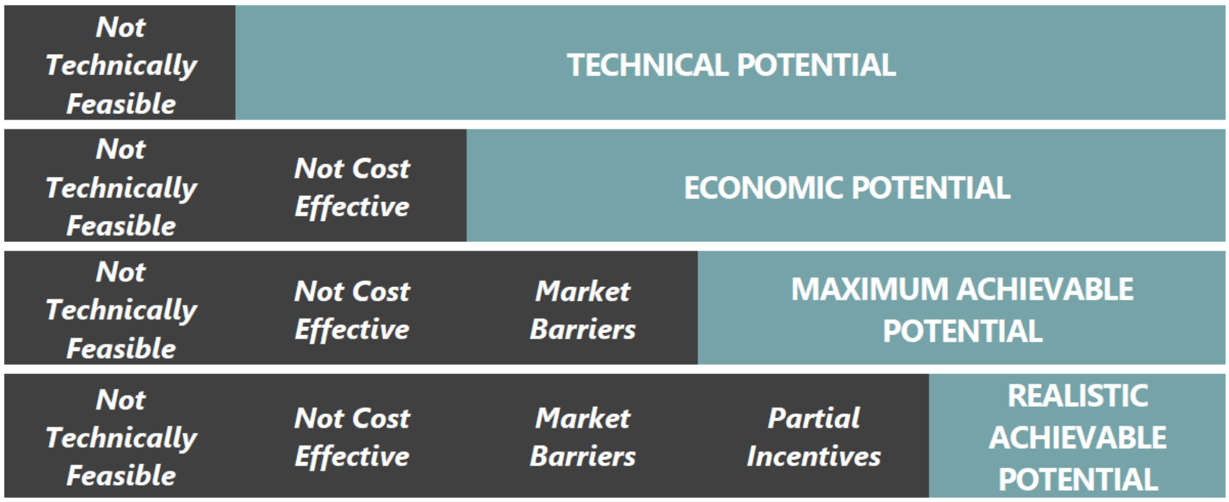
5.5.3 Market Potential Study ("MPS") and End Use Analysis

170 IAC 4-7-4(15) 170 IAC 4-7-6(b)(2)(B) 170 IAC 4-7-6(b)(2)(C)

The primary objective of the MPS was to establish Technical, Economic, Maximum Achievable, and Realistic Achievable Potentials for DSM in IPL's service territory. IPL contracted GDS to conduct this analysis which began in the Fall of 2018. To summarize the process, GDS developed the potential savings estimates by 1) creating IPL's Market Characterization or establishing a forecast of the saturation and efficiency levels of existing equipment used by IPL's customers; 2) creating the Measure Characterization or developing a comprehensive list of cost-effective energy efficiency measures; 3) developing Potentials or estimating adoption of the list energy efficiency measures using the saturation and efficiency forecast as a basis for efficiency uptake. Through this approach, the Technical, Economic, Maximum Achievable, and Realistic Achievable Potential estimates were developed which are defined as follows and graphically illustrated in Figure 5.37:

- Technical Potential – potential for DSM adoption that assumes no barriers to customer adoption, e.g. financial limitations, customer awareness, and willingness to participate.
- Economic Potential – potential for DSM that only includes measures that are deemed to be cost-effective based on a measure-level screening using the Utility Cost Test (UCT).
- Maximum Achievable Potential – potential for DSM that assumes paying an incentive equal to 100% of the measure incremental cost and limited barriers to participation.
- Realistic Achievable Potential – potential for DSM that assumes the incentives paid for DSM and barriers to participation are aligned with historic levels with no constraints placed on spending.

Figure 5.37 | Market Potential



GDS initially undertook an End Use Analysis beginning in the Fall of 2018. The purpose of the End Use Analysis was to determine the saturation and efficiency levels of equipment located on the premises of IPL's residential, commercial and industrial properties. These equipment saturations and efficiencies established the baseline year for the load forecast and helped establish the Market Characterization for DSM opportunities. GDS conducted 231 residential, 68 commercial, and 40 industrial customer surveys that gathered customer information on the volume and type of equipment located at their location. Additionally, GDS followed up with 40 residential, 68 commercial, and 40 industrial site visits to confirm the information provided by the customers in the survey. Historically, end use information was taken from the Energy Information Association's saturation and efficiency outlook for the region. IPL decided to include the End Use Analysis as part of this MPS in order to improve the accuracy of the represented baseline. For more information on the End Use Analysis, including residential, commercial, and industrial saturation and efficiency levels see pages 3 – 10 in GDS' Market Potential Report attached as Attachment 5.1 to this IRP. The electronic appendices of the IPL/GDS MPS are included as Attachments 5.2a - c. The annual and lifetime energy and demand savings associated with the decrement bundles is included in Attachment 5.3.

In order understand of the current market segments in IPL's service territory or create a Market Characterization for efficiency, GDS defined the appropriate market sectors, market segments and equipment vintages, saturations, and end uses. Informed by the End Use Analysis described earlier, the Market Characterization set a baseline or current state of appliance saturations and efficiency adoption. GDS used propriety modeling tools like BeOpt™ for the Residential Sector to disaggregate customer usage and NAICS code data to segment the Commercial and Industrial businesses for efficiency adoption.

Next, GDS developed a comprehensive list of energy efficiency technologies suitable for IPL's market. IPL worked closely with stakeholders in reviewing and developing the list to ensure all technologies were assessed. In addition to stakeholder suggestions, the list was informed by a range of sources including the Indiana and other state Technical Reference Manual ("TRM"), IPL's current program offerings and other commercially viable emerging technologies. GDS also defined the measure savings, cost and useful life assumptions in this step using sources like the Indiana and Illinois TRM, Michigan Energy Measures Database ("MEMD"), and National Renewable Energy Labs ("NREL") Energy Measures Database.

GDS carefully considered the assumptions used for LED lighting when formulating the Measure Characterization. With rollbacks of codes and standards, LED savings assumptions have proven to be a moving target. From GDS' MPS report (Attachment 5.1) – "Recognizing that there remains significant uncertainty regarding the future potential of residential screw-in lighting, GDS reviewed the latest lighting-specific program designs and consulted with industry peers to develop critical assumptions regarding the future assumed baselines for LED screw base omnidirectional, specialty/decorative, and reflector/directional lamps over the study timeframe.

EISA Impacts. LED screw base omnidirectional and decorative lamps are impacted by the EISA 2007 regulation backstop provision, which requires all non-exempt lamps to be 45 lumens/watt, beginning in 2020. Based on this current legislation, the federal baseline in 2020 will be roughly equivalent to a CFL bulb. However, in January 2017, the Department of Energy expanded the scope of the standard to include directional and specialty bulb but stated that they may delay enforcement based on ongoing dialog with industry stakeholders. Although there is uncertainty surrounding EISA and the backstop provision, the Market Potential Study assumes the backstop provision for standard (A-lamp) screw-in bulbs will take effect beginning in 2022. The analysis assumes the expanded definition of general service lamps to include specialty and reflector sockets will impact those sockets beginning in 2023. Last, the analysis assumes a limited opportunity for direct install of LED bulbs replacing halogen bulbs through 2024 in both low-income and non-low-income households." Figure 5.38 provides the assumed lighting baseline technology by year used in the MPS.

Figure 5.38 | Lighting Baseline Technology by Year

Delivery Approach/Bulb Type	2021	2022	2023	2024
Buydown				
Standard LED	Halogen	CFL	CFL	CFL
Specialty LED	Incandescent	Incandescent	CFL	CFL
Reflector LED	Incandescent	Incandescent	CFL	CFL
Direct Install				
Standard LED	Halogen	Halogen	Halogen	CFL
Specialty LED	Incandescent	Incandescent	Incandescent	CFL
Reflector LED	Incandescent	Incandescent	Incandescent	CFL

GDS used an Excel-based model to determine the Technical, Economic, Maximum Achievable, and Realistic Achievable Potential estimates from the Market Characterization and Measure Characterization assumptions. The Technical and Economic Potential are considered the upper bound for DSM, where even the best designed and most expensive portfolios would fall short of achieving the targets. The Maximum Achievable and Realistic Achievable Potentials are developed in order to define attainable targets. Figure 5.39 provides the cumulative savings results from the Residential Potential Analysis. Lighting makes up a small portion of the overall potential whereas it encompasses over 50% of the savings in IPL's 2018 portfolio of programs.

Figure 5.39 | Residential Energy Efficiency Potential Results 2021 – 2029 (Gross MWh)

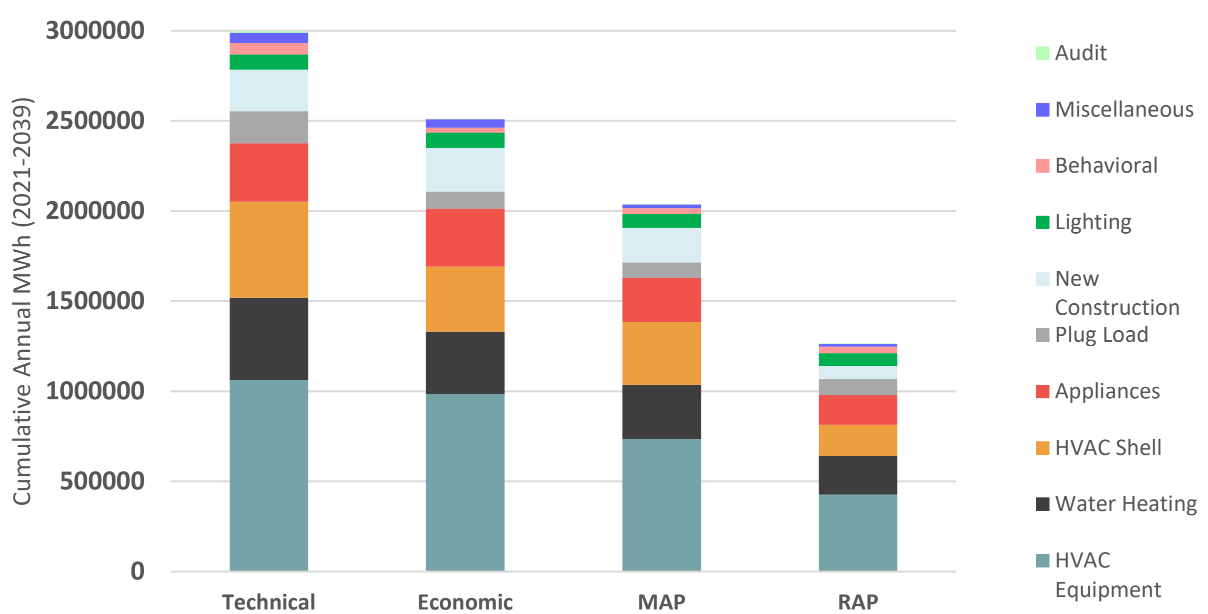
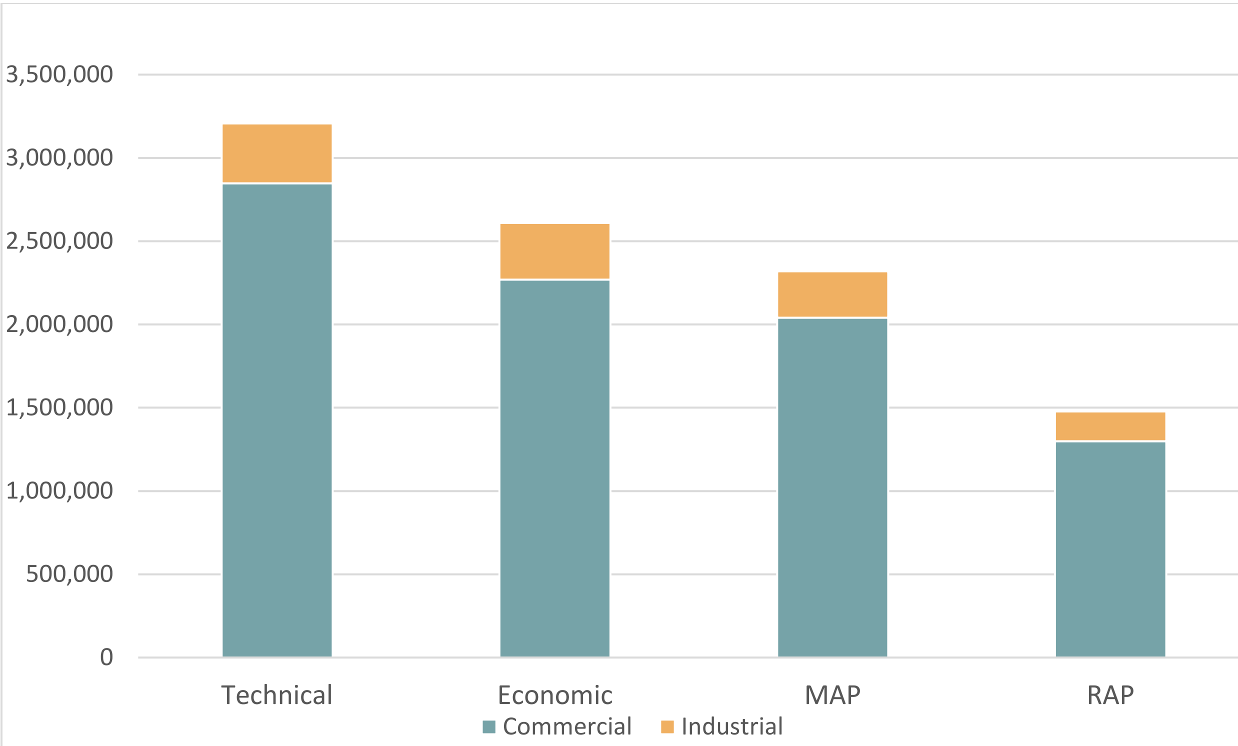


Figure 5.40 provides the cumulative savings results from the C&I Potential Analysis. Because 40% of Industrial savings have opted out of participation, the bulk of the potential savings comes from the commercial sector.

Figure 5.40 | C&I Energy Efficiency Potential Results 2021 – 2029 (Gross MWh)



DSM Bundling for Resource Selection Model

For the IRP Resource Selection Model to evaluate DSM on a consistent and comparable basis with supply-side resources, the DSM potential defined by the MPS had to be disaggregated into smaller bundles with supply-side characteristics that act as model inputs. IPL worked closely with GDS and its stakeholders to formulate an approach to bundling DSM that addressed stakeholder requests, met the IURC rules and fit the IRP PowerSimm model requirements.

In early 2019, with the MPS nearly wrapped, the bundling process initiated with a meeting between IPL and its stakeholders with confidentiality agreements. The Citizen's Action Coalition (CAC) and their consultant presented their preferred method for integrating DSM into the IRP model called the Decrement Pricing Methodology. IPL liked the basic idea of the methodology which (at a very high level) consisted of loading DSM savings equal to 2% of IPL load divided up into 0.25% of load decrements and letting the model determine an avoided cost (equal to the change in PVRR with and without the DSM loaded in). The CAC suggested that the resulting avoided cost along with the 2% savings target be put in a Request for Proposals from energy efficiency implementation vendors; where vendors must bid to hit the 2% savings target for a price less than or equal to the total avoided cost. IPL like the approach but had some concerns: 1) if avoided costs are made available to bidders, then bidders would likely provide bids equal to the avoided cost in the RFP meaning the energy efficiency portfolio would breakeven and not maximize cost effectiveness to customers; DSM benefits = DSM costs 2) if through the RFP process bidders indicate the 2% savings level cannot be achieved, then the IRP and the plans for future generation that had been optimized at the 2% savings level would be need to be reevaluated at a lower savings level.

IPL decided to employ the core concepts of the Decrement Pricing Methodology where the DSM bundles are defined as 0.25% reductions in load; however, instead of including the full avoided costs in an RFP as the DSM cost ceiling, IPL let the model determine a cost-effective level of DSM based on predefined DSM cost inputs. These predefined costs were based on IPL's current costs to deliver DSM assigned to the individual measures.

Figure 5.41 provides a graphical representation of the bundling approach. The blue line represents a DSM supply curve which is built up from the individual measures in the RAP. IPL and GDS divided the supply curve up into eight sections or "bundles" starting from the most cost-effective measures to the least cost-effective measures. Each bundle had a levelized cost defined by the measures making up the bundle and an 8760 hourly load shape. Load shapes were assigned to each measure from GDS' load shape database. Each bundles load shape was then aggregated from the individual measure load shapes. There are eight total bundles with each bundle representing 0.25% of load totaling 2% of total load reduction. Each additional 0.25% bundle decrement becomes more expensive because a higher DSM target is more expensive to achieve. Each bundle spans the IRP 2021 – 2039 planning period (2020 already determined in DSM Cause No. 44945) and includes both residential and C&I potentials.

Figure 5.41 | MPS – Realistic Achievable Potential Supply Curve

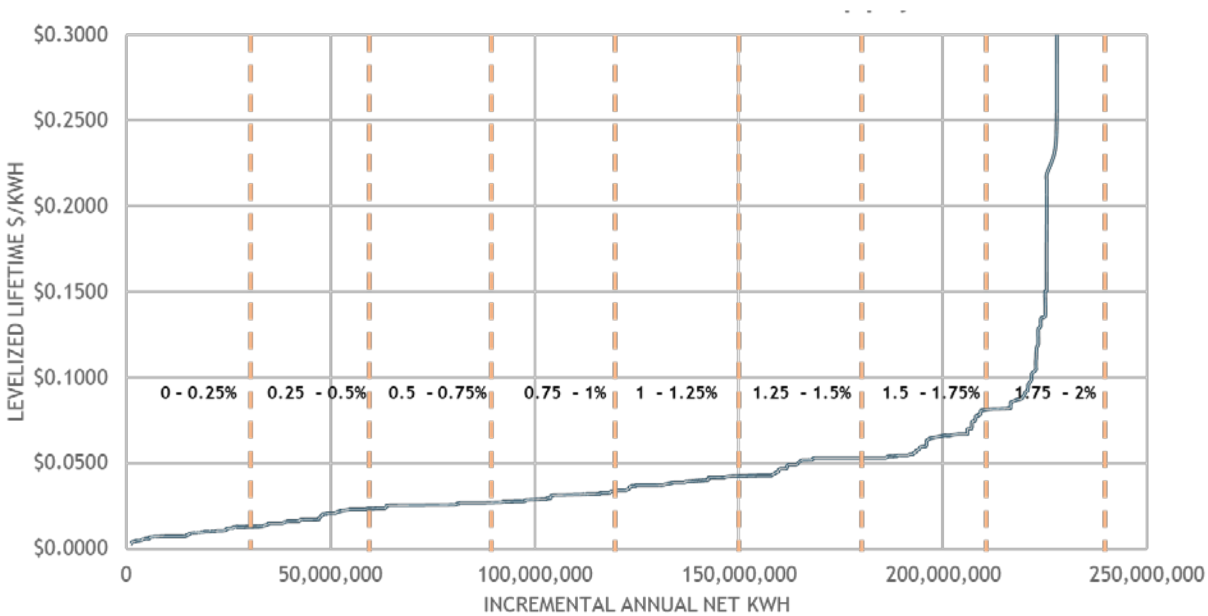


Figure 5.42 illustrates the impacts from the decrement bundles to forecasted load. If IPL were to implement net DSM at an annual level of 2% of incremental sales or all eight bundles over the planning period, the cumulative impacts from DSM would reduce load by 16% in 2039. This level would be equal to the Realistic Achievable Potential as defined by the MPS.

Figure 5.42 | Cumulative Impacts to Forecasted Load from the DSM Decrement Bundles

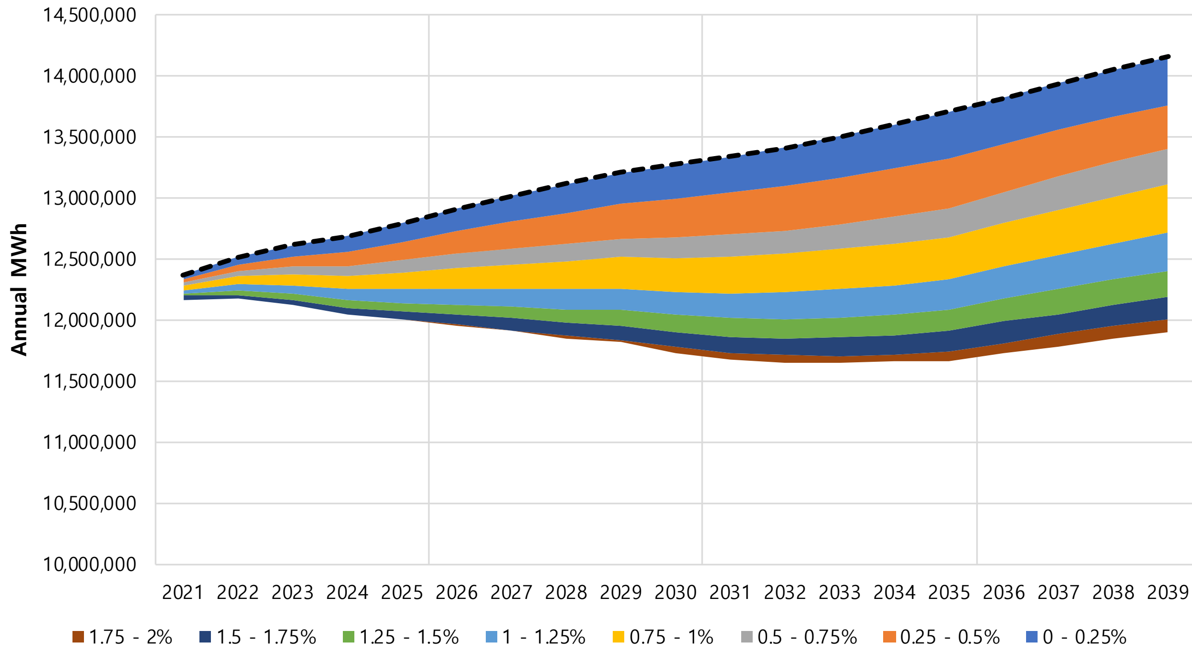


Figure 5.43 provides the cumulative savings and costs of layering on each additional DSM decrement.

Figure 5.43 | Decrement Analysis – Cumulative Savings and Costs

Decrement Bundle	Cumulative Savings		
	2021	2022	2023
1	30,814,371	31,103,684	31,531,181
2	60,658,921	59,378,674	60,844,869
3	92,528,755	92,307,819	93,566,503
4	119,719,071	124,673,163	125,425,014
5	141,300,182	140,748,140	144,427,177
6	185,443,755	186,853,815	189,209,272
7	201,245,927	196,461,290	200,408,981
8	0	0	0

Decrement Bundle	Cumulative Cost		
	2021	2022	2023
1	$ 2,332,292	$ 2,467,717	$ 2,622,880
2	$ 7,196,788	$ 7,184,013	$ 7,820,975
3	$ 10,269,242	$ 12,475,433	$ 13,319,451
4	$ 17,272,179	$ 19,666,137	$ 21,028,804
5	$ 23,817,857	$ 26,735,711	$ 29,199,022
6	$ 32,392,949	$ 41,791,240	$ 43,555,236
7	$ 44,232,408	$ 49,636,535	$ 54,343,744
8	$ -	$ -	$ -

Decrement Bundle	Cost/kWh		
	2021	2022	2023
1	$ 0.076	$ 0.079	$ 0.083
2	$ 0.119	$ 0.121	$ 0.129
3	$ 0.111	$ 0.135	$ 0.142
4	$ 0.144	$ 0.158	$ 0.168
5	$ 0.169	$ 0.190	$ 0.202
6	$ 0.175	$ 0.224	$ 0.230
7	$ 0.220	$ 0.253	$ 0.271
8	$ -	$ -	$ -

Demand Response

IPL included two Demand Response bundles as inputs into the Resource Selection Model. The first bundle was comprised of residential and commercial air conditioner load management measures with all load impacts occurring during the summer. The second bundle was comprised of residential and commercial water heater control measures with both summer and winter load impacts. Like the EE bundles, each bundle ran the duration of the study period (2021 – 2039) and had a levelized cost and 8760 load shape as model inputs.

IPL has implemented its Air Conditioner Load Management program since 2003. Currently, the company has roughly 55,000 Landis and Gyr switches, Cannon switches and smart thermostats with the capability of shedding approximately 35MW of air conditioner load during peak summer hours. IPL plans to maintain this existing device population over the IRP planning period. As such, annual maintenance costs to replace switches that have reached the end of their effective useful life and incentives to pay customers for program participation were included as costs in the IRP planning model.

5.5.4 DSM Bundles in Model

The eight DSM decrements were loaded into PowerSimm as negative load items with hourly energy profiles for the twenty years of the IRP study window. Each decrement was tied to a price ($/MWh) composing the decrement's levelized cost. Because the decrements are *negative* load, PowerSimm calculates a positive energy revenue stream where they are paid the IPL Load Zone Locational Marginal Price ("LMP") for every MWh of their profile. This is done because the decrement effectively offsets purchasing IPL load at that same price for the MWh in the decrement's profile. A cost is applied to the decrement at its levelized cost. If the IPL Load Zone LMP is greater than the levelized cost, then the decrement is a net benefit to the portfolio based on its energy savings.

The capacity credit for each DSM decrement was established by determining its contribution to IPL's peak load which is forecasted to occur in July each year between HE15 and HE18. Each decrement's hourly contribution across these four hours for all thirty-one days of July were averaged together to arrive at the decrement's capacity credit. The capacity credit increases with time as the decrement energy savings accumulate but is held constant within a year. The capacity credit from each of the decrements counted towards meeting IPL's Planning Reserve Margin Requirement.

5.5.5 Avoided Cost Calculation

170 IAC 4-7-4(29) 170 IAC 4-7-6(b)(1)

Avoided cost is defined in 170 IAC 4-7-1(b) as "the incremental or marginal cost to a utility of energy or capacity, or both, not incurred by a utility if an alternative supply-side resource or demand-side resource is included in the utility's IRP".

The avoided cost used in the MPS are shown in Confidential Attachment 5.4. The energy and generation capacity costs are from the Wood Mackenzie H1 2018 No Federal Carbon Case.

Transmission and distribution components were calculated based upon avoiding upgrades to circuits that may be needed to serve additional load. The transmission costs are assumed to be negligible due to the robust interconnections of the 34 kV and 138 kV systems. Significant upgrades are not needed for load growth. The majority of recent transmission and substation projects focus on integrating new generating resources and mitigating import limitations, not load growth. A proxy value of 10% of the avoided distribution costs was included in the avoided cost calculation for potential avoided transmission costs.

The distribution costs were calculated based on an equally weighted average costs to build new overhead and underground circuits to serve 10 MW which is the standard circuit capacity design. The cost per mile was divided by the circuit capacity of 10 MW or 10,000 kW to arrive at a cost per kW. Annual fixed charges were calculated based on this cost times the levelized fix charge rate in IPL's most recent Rate CGS filing. The sum of these costs was multiplied by 20% to reflect the approximate number of the distribution circuits that would likely require upgrades based on current circuit loading.

The aggregate avoided costs were used in the DSM MPS by GDS to calculate the NPV of DSM lifetime benefits.

5.6 Rate Design

IPL considers and reviews rate design options which include appropriate cost of service and recovery mechanisms and encompass innovative approaches. Through its energy efficiency programs, demand response programs, Rate CGS, curtailable energy riders, and load displacement rider, IPL employs a range of rate options.

Section 6: Environmental Considerations

170 IAC 4-7-4(23) 170 IAC 4-7-6(a)(4)

6.1 Environmental Overview

Environmental regulations significantly affect IPL's resource planning efforts due to their dynamic and, in many cases, uncertain nature. The majority of these regulations are promulgated by the U.S. EPA and enforced by this agency and/or Indiana Department of Environmental Management ("IDEM"). IPL stays informed of proposed and final rules and determines their effects on Company assets and customer impacts. The most significant changes in recent history focus on fossil fuel-fired plants. IPL's natural gas-fired CCGT was designed in accordance with the most up-to-date regulations to ensure compliance. This section of the IRP focuses on compliance aspects of environmental regulations.

The most relevant recent activities related to environmental regulations include the following:

- In August 2014, EPA finalized a revised regulation requiring utilities to reduce the adverse impacts to fish and other aquatic life caused by cooling water intake structures.
- In April 2015, EPA finalized revised regulations for Coal Combustion Residuals ("CCRs") regulating CCRs as a solid waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"). Revisions to the rule have followed and remain under development.
- In July 2016, EPA published the final updated chronic aquatic life criterion for the pollutant selenium (Se) in freshwater per Clean Water Act section 304(a). The revised criterion is a recommendation to states authorized to establish water quality standards under the Clean Water Act.
- In July 2019, EPA published the final Affordable Clean Energy (ACE) Rule, regulating GHGs from existing coal-fired electric generating units, and replacing the 2015 Clean Power Plan.

Some of these rules have required additional investments for compliance and some may require future investments. Planning for compliance with environmental regulations can be complicated by uncertainty surrounding the final outcome of the regulations and their impacts, including timing, and potential legal and legislative activity.

These types of uncertainties and environmental regulations are incorporated into the IRP process and discussed in detail later in this section following a review of the existing environmental rules and regulations.

6.2 Existing Environmental Regulations

Existing environmental regulations associated with air emissions, water, and wastes that impact IPL's resources are described below.

6.2.1 Air Emissions

170 IAC 4-7-4(21)

IPL is subject to various regulations related to air emissions.

Sulfur Dioxide (SO_2)

In response to Title IV of the Clean Air Act Amendments of 1990 ("CAAA"), IPL developed an Acid Rain Compliance Plan that was submitted to the IURC on July 1, 1992, (IURC Cause No. 39437) and subsequently approved on August 18, 1993 ("39437 Order").[22] This plan called for the installation of SO_2 retrofit Flue Gas Desulfurization ("FGD") units on Pete Unit 1 and Pete Unit 2. These FGD units were placed in-service in 1996. FGD is the technology used for removing SO_2 from the exhaust flue gases from coal-fired power plants.

The SO_2 regulations remained relatively unchanged as did the IPL compliance plan until March 10, 2005, when the EPA issued Clean Air Interstate Rule ("CAIR") which established a regional cap-and-trade program for SO_2 and NO_x. Phase I of CAIR for SO_2 had an effective date of January 1, 2010 and Phase II of CAIR was scheduled to become effective on January 1, 2015.

In anticipation of this CAIR regulatory program and to help meet the existing CAAA regulatory requirements, IPL developed a Multi-Pollutant Plan ("MPP") that was submitted to the IURC on July 29, 2004, (IURC Cause No. 42700) requesting approval of certain core elements of the plan which were approved on November 30, 2004. In order to reduce SO_2 emissions, IPL completed the Petersburg Generating Station ("Pete") Unit 3 FGD enhancement (May 2006) and the new Harding Street Generating Station ("HSS") Unit 7 FGD (September 2007). IPL also identified the enhancement of the Pete Unit 4 FGD as a core element of its MPP and completed the Pete Unit 4 FGD upgrade project (IURC Cause

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[22] The 39437 Order was subsequently reversed by the Court of Appeals and the matter was remanded by the Commission. *General Motors Corporation et al v. Indianapolis Power & Light Company*, 654 N.E. 2d 752 (Ind. Court of Appeals. June 30, 1995). While the appeal was being heard, IPL, on April 8, 1994, filed a general rate case (IURC Cause No. 39938) which was ultimately resolved by settlement ("39938 Settlement). In the 39938 Settlement, the parties committed to take no further action to oppose the affirmative relief sought by IPL as approved in the Commission August 8, 1993 Order. Following IURC approval of the 39938 Settlement, the remand proceeding was dismissed. See Order in Cause No. 39437 dated August 21, 1996.

No. 43403 approved April 2, 2008) in 2011 to help meet the additional SO_2 emission reduction requirements. IPL met the CAIR requirements for SO_2 upon completion of these projects and by supplementing its compliance plan with the purchase of emission allowances on the open market as needed.

As a result of legal proceedings related to CAIR, the EPA issued a final replacement rule, known as Cross State Air Pollution Rule ("CSAPR") in July 2011. Finally, following resolution of legal proceedings, CSAPR became effective on January 1, 2015, and CAIR ceased to apply at that time. Phase II of CSAPR became effective on January 1, 2017. IPL meets CSAPR requirements through the operation of our existing pollution control equipment coupled with the purchase of allowances on the open market, as needed, and plans to continue to comply with Phase II CSAPR using these measures.

Additional SO_2 requirements and compliance plans are discussed below under NAAQS.

Oxides of Nitrogen (NOx)

In order to meet more stringent NO_x emission reduction requirements which became effective in 2004 related to the NOx State Implementation Plan ("SIP") Call, IPL installed Selective Catalytic Reduction ("SCR") equipment on Pete Unit 2, Pete Unit 3 and HSS Unit 7 along with several low NO_x clean coal technology ("CCT") projects on other units. The Pete SCR units commenced operations in May 2004, whereas the HSS Unit 7 SCR came online in May 2005.

As previously discussed, the EPA issued CAIR in May 2005, which was subsequently replaced by CSAPR requirements. On September 7, 2016, EPA finalized the CSAPR Update Rule which established NOx reductions during ozone season for 22 states, including Indiana, to address downwind attainment with the 2008 Ozone NAAQS of 75 parts per billion (ppb). On September 13, 2019, the D.C. Circuit remanded a portion of the CSAPR Update Rule to EPA because it did not set a deadline by which upwind states must eliminate their significant contribution to downwind states' NAAQS nonattainment. At this time, it is uncertain whether future revisions to CSAPR resulting this decision could further impact IPL's NOx emissions limits. IPL currently meets requirements for NO_x through the operation of existing pollution control equipment coupled with the purchase of allowances on the open market, as needed, and currently plans to continue to comply using these measures.

Regional Haze

A Regional Haze Rule established planning and emissions reduction timelines for states to use to improve visibility in national parks throughout the U.S. The rule sets guidelines for states in setting

Best Available Retrofit Technology ("BART") at older power plants. Following rulemaking and litigation related to CAIR described above, EPA promulgated a final rule in 2012, finding CSAPR is "better than BART" in states participating in the CSAPR trading program, including Indiana. EPA published a rule reaffirming this determination on September 29, 2017.

State Implementation Plans addressing the second implementation period (2018-2028) for the Regional Haze Rule will be due to EPA by July 31, 2021 and EPA released guidance to assist states in developing revised SIPs on August 20, 2019. It remains uncertain whether a future revised Regional Haze SIP could result in more stringent emissions limitations for IPL.

Mercury and Air Toxics Standard ("MATS")

In February 2012, EPA issued the final MATS Rule which placed stringent emission limits on Hazardous Air Pollutants ("HAPs"), as defined in Section 112 of the Clean Air Act ("CAA").

IPL developed a Compliance Plan, which included activated carbon injection and sorbent injection for mercury control and upgraded FGDs for acid gas control on all coal-fired units. The Plan also included upgraded electrostatic precipitators on Petersburg Units 1 and 4, and Harding Street Unit 7, in addition to baghouses on Petersburg Units 2 and 3 for particulate and mercury control. In development of IPL's MATS Compliance Plan, it also was determined that installation of the necessary controls was not economical for the smaller, less controlled units, Eagle Valley Units 3-6, and Harding Street Units 5 and 6.

IPL received IURC approval in Cause No. 44242 to proceed with its MATS Compliance Plans, and construction of Petersburg controls was completed. However, it was later determined when considering new National Pollutant Discharge Elimination System ("NPDES") requirements and other potential future environmental regulations for HSS Unit 7 that the MATS controls were no longer the reasonable least cost solution. IPL received IURC approval in Cause No. 44540 to refuel HSS Unit 7 from coal to natural gas instead of pursuing the previously approved retrofit. See the Water section below for more detail on NPDES requirements.

National Ambient Air Quality Standards ("NAAQS")

EPA is required under the CAA to set NAAQS for air pollutants that endanger public health or welfare. There are several NAAQS, but typically only three directly impacting coal-fired power plants: SO_2, ozone, and particulate. NAAQS do not directly limit emissions from utilities, but states must develop State Implementation Plans ("SIPs") to achieve emissions reductions to address each NAAQS when an area is designated as nonattainment. EPA reviews NAAQS and the science on which they are based on a five-year basis. This review process includes gathering input from the scientific community and the public, an integrated science assessment, a risk and exposure assessment, and a policy assessment.

The counties in which IPL operates power generation facilities are all currently designated as attainment for all air pollutants, except sulfur dioxide. On June 22, 2010, EPA revised the NAAQS for SO_2 from 140 parts per billion ("ppb") on 24-hour basis to 75 ppb on a one-hour basis. The areas in which IPL Harding Street, Eagle Valley, and Petersburg operate were designated as nonattainment with the lowered standard. As a result, IDEM developed a SIP to address the 2010 SO_2 NAAQS, and on September 30, 2015, published revisions to 326 IAC 7-4-15 establishing new and more stringent emission limits for Pete Units 1-4 with compliance required by January 1, 2017 as shown in Figure 6.1.

Measures needed to enhance the performance and integrity of the FGD systems at Petersburg in order to meet these limits were approved by the IURC in Cause No. 44794. As required, IPL has been complying with these limits since January 1, 2017 through the operation of pollution controls equipment.

On August 7, 2019 IDEM issued a Notice and Order of the Commissioner, as a result of an updated evaluation implementing the revised SO_2 emissions limitations (30-day rolling average) which became effective on September 24, 2019

Figure 6.1 | NAAQs Emission Limits for IPL Petersburg Units

Emission Unit Description	Beginning January 1, 2017		Beginning September 24, 2019
	Emission Limit (lbs/hour – 30 day rolling average)	Emission Limit (lbs/MMBtu – 30 day rolling average)	Emission Limit (lbs/MMBtu – 30 day rolling average)
Unit 1	263.0	0.12	0.10
Unit 2	495.4	0.12	0.10
Unit 3	1,633.7	0.29	0.25
Unit 4	1,548.2	0.28	0.24

IPL meets these emission limits through the operation of existing pollution control equipment.

Greenhouse Gas

On October 23, 2015, the EPA finalized CO2 emission rules for existing power plants under CAA Section 111(d), called the Clean Power Plan ("CPP"). On February 9, 2016, the U.S. Supreme Court issued orders staying implementation of the CPP pending resolution of legal challenges to the rule. On July 8, 2019, EPA published the final Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units, known as the Affordable Clean Energy ("ACE") Rule along with associated revisions to implementing regulations. The final ACE Rule replaced the 2015 CPP and determined that heat rate improvement measures are the Best System of Emissions Reductions ("BSER") for existing coal-fired electric generating units. The final rule requires the State of Indiana to develop a State Plan to establish CO2 emission limits for designated facilities, including IPL Petersburg's coal-fired electric generating units. States have three years to develop their plans under the rule (until September 2022) and are required to consider candidate technologies identified in the rule to establish CO2 emission rate limits. States may consider remaining useful life and other factors when establishing emission limits. Compliance with CO2 emission rate limits will be required within 24 months of State Plan deadline or additional time may be allowed with establishment of a compliance schedule. Impacts remain largely uncertain because a State Plan has not yet been developed.

Existing Controls to Reduce Air Emissions

As shown in Figure 6.2, IPL has already installed environmental pollution control equipment at its facilities.

Figure 6.2 | IPL Generating Units: Environmental Controls

Unit	Fuel	Summer Output (MW)	Environmental Controls
Pete Unit 1	Coal	232	FGD, NN, LNB/OFA, ESP, ACI, SI
Pete Unit 2	Coal	435	FGD, SCR, LNB/OFA, BH, ACI, SI
Pete Unit 3	Coal	540	FGD, SCR, BH, ACI, SI
Pete Unit 4	Coal	545	FGD, NN, LNB, ESP, ACI, SI
Pete DG	Diesel	8	
HSS Unit 5	Gas	100	
HSS Unit 6	Gas	100	
HSS Unit 7	Gas	430	SCR
HSS CTs 1-2	Oil	60	
HSS CT 4	Oil/Gas	82	Water Injection
HSS CT 5	Oil/Gas	82	Water Injection
HSS CT 6	Gas	158	LNB
HSS DG	Diesel	3	
Georgetown GT 1	Gas	79	LNB
Georgetown GT 4	Gas	79	LNB

Note: Acronyms used in Figure 6.2 – ACI (Activated Carbon Injection), ESP (Electrostatic Precipitator), FGD (Flue Gas Desulfurization), LNB (Low NO_x Burner), NN (Neural Net), Overfire Air (OFA), SCR (Selective Catalytic Reduction), SNCR (Selective Non-Catalytic Reduction)

6.2.2 Water

The National Pollution Discharge Elimination System ("NPDES") permit system obtains its authority from Clean Water Act ("CWA"). Section 402 requires permits for the direct discharge of pollutants to the waters of the U.S. These permits, which IPL maintains for each of its power plants, have three main components: technology based and water quality based effluent limitations; monitoring requirements; and reporting requirements.

Effluent limitations identify the nature and amount of specific pollutants that facilities may discharge from regulated outfalls which are identified by unique numbers and internal wastewater streams as defined by 40 CFR Part 423. Currently, the NPDES permits require that the outfalls be monitored regularly for specified parameters.

On August 28, 2012, the IDEM issued NPDES permit renewals to Petersburg and Harding Street. These permits contained new Water Quality Based Effluent Limits ("WQBELs") and Technology-Based Effluent Limits ("TBELs") for the regulated facility NPDES discharges with a compliance date of October 1, 2015, for the new WQBELs, which was later extended. New metal limits drove the need for additional wastewater treatment technologies at Petersburg and Harding Street. However, IPL determined that installation of the necessary wastewater treatment technologies and other potential future environmental requirements in addition to the necessary Mercury and Air Toxic Standard ("MATS") controls described in IPL's case-in-chief Cause No. 44242 were no longer the reasonable least cost plan for HSS. Instead, IPL obtained approval in Cause No. 44540 to refuel HSS Unit 7 to operate on natural gas which reduces the cost to comply with environmental regulations and reduces the impact on the environment. IPL also received approval of wastewater treatment systems necessary to comply with the new limits in the 2012 NPDES permit renewals in IPL's Cause No. 44540. For Petersburg Generating Station, this included dry fly ash handling, zero liquid discharge systems for FGD wastewater, and a tank-based treatment system of other wastewaters generated at Petersburg.

On November 3, 2015, EPA published the final revisions to the Effluent Limitations Guidelines ("ELG") Rule. The revised ELG regulations require dry fly ash handling, dry or closed-loop bottom ash handling, and apply numerical limits on FGD Wastewater. Eagle Valley and Harding Street Generating Stations no longer generate these wastewater streams as they have ceased coal combustion. Petersburg Generating Station will comply with the dry fly ash handling and limits on FGD Wastewater as a result of the NPDES Wastewater treatment project in Cause No. 44540. In addition, the ELG will require dry or closed-loop bottom ash handling at Pete with compliance required by a date to be specified by the NPDES permitting authority that is between November 1, 2018, and December 31, 2023. Pete will comply with this ELG requirement as a result of the closed-loop bottom ash dewatering system included in the Compliance Project proposed in Cause No. 44794 and described below for compliance with the Coal Combustion Residuals ("CCR") Rule. On April 12, 2019, the U.S. Court of Appeals for the Fifth Circuit vacated and remanded portions of EPA's 2015 ELG Rule related to legacy wastewaters and combustion residual leachate.

On November 22, 2019, EPA published proposed revisions to the ELG Rule, specifically for FGD wastewater and bottom ash transport water.

In addition to establishing effluent limits, the NPDES permit also includes compliance requirements with Section 316(a), Section 316(b) of CWA and water quality criteria. Sections 316(a) and 316(b) and revised Selenium water quality criterion are described below.

Clean Water Act Section 316(a)

327 IAC 5-7 and Section 316(a) of the CWA authorizes the NPDES permitting authority to impose alternative effluent limitations for the control of the thermal component of a discharge in lieu of the effluent limits that would otherwise be required under sections 301 or 306 of the CWA. Regulations implementing section 316(a) are codified at 40 CFR Part 125, subpart H. These regulations identify the criteria and process for determining whether an alternative effluent limitation (i.e., a thermal variance from the otherwise applicable effluent limit) may be included in an NPDES permit and, if so, what that limit should be. This means that before a thermal variance can be granted, the permittee must demonstrate that the otherwise applicable thermal discharge effluent limit is more stringent than necessary to assure the protection and propagation of the waterbody's balanced, indigenous population ("BIP") of shellfish, fish and wildlife. If the variance study determines there is an impact, IPL Petersburg may need to employ additional thermal reduction technology such as closed cycle cooling in order to meet the temperature water quality standards. IPL is currently in the process of conducting thermal studies at the Petersburg and Harding Street facilities based on guidance developed by the Indiana Department of Environmental Management ("IDEM") which includes conducting comprehensive monitoring programs for temperature in the waterbody, conducting comprehensive monitoring programs to delineate the thermal discharge plume in the receiving waterbody, and conducting biological community assessments. The results of these studies will be included in the 316(a) demonstration and the demonstration is required to be submitted to IDEM. Petersburg submitted their 316(a) demonstration to IDEM in December 2017. Harding Street is required to submit their 316(a) demonstration to IDEM in December 2019. If IPL is unable to obtain an acceptable 316(a) variance based on the submitted demonstrations, Indiana thermal water quality standards would apply. In this scenario, the potential s could be similar to the range of impacts described under 316(b) and will be included in subsequent IRP analyses.

Cooling Water Intake Structures – Clean Water Act Section 316(b)

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of Cooling Water Intake Structures ("CWIS") reflect the best technology available for minimizing adverse environmental impact. Specifically, the 316(b) Rule is intended to reduce the impacts to aquatic organisms through impingement and entrainment due to the withdrawal of cooling water by facilities.

On August 15, 2014, EPA published a final rule which would set requirements that establish the Best Technology Available ("BTA") to minimize these impacts.

The entrainment BTA could be determined to be closed cycle cooling systems. Alternatively, utilities could be faced with installing less costly controls, like modified travelling screens and fish handling and return systems to address impingement BTA. Another is equipped with a cooling tower which dissipates approximately one-half of the waste heat generated by that unit. One of the three IPL coal-fired units at Harding Street is currently equipped with closed cycle cooling systems. The impact of this rule will be dependent upon IDEM's determination for impingement and entrainment BTAs for both Petersburg and Harding Street.

6.2.3 Solid Waste

The solid waste generated at IPL's power plants is classified as either non-hazardous or hazardous. IPL generates hazardous and non-hazardous waste with the handling of both waste streams regulated under the Resource Conservation and Recovery Act ("RCRA").

Hazardous Waste

Hazardous waste is regulated under RCRA Subtitle C. There are three categories of hazardous waste generators for industry with each category having its own scope of regulations that must be met. The more hazardous waste that is generated, the higher the risk to the environment, hence the more regulation and oversight is imposed.

The three categories of hazardous waste are: 1) large quantity generator ("LQG"); 2) small quantity generator ("SQG"); and 3) conditionally exempt small quantity generator ("CESQG"). IPL plants are historically categorized as SQG and CESQG. As such, IPL faces minimal regulations and risk in this area.

Non-Hazardous Waste

Solid waste is regulated under Subtitle D of RCRA. IPL coal-fired operations generate a large amount of solid waste every year that must be handled in accordance with this regulation. The primary sources of non-hazardous waste in the coal-fired steam electric industry are fly ash and bottom ash generated from coal combustion, and scrubber sludge or gypsum resulting from the FGD process.

Ash has historically been placed in ponds for treatment via sedimentation, from which the effluent is regulated pursuant to NPDES. Ash dredged from the ponds has historically been shipped back to mines or otherwise beneficially used in an environmentally sound manner. In addition, fly ash has been mixed with dewatered scrubber sludge and lime to make a stabilized product which is disposed of in a permitted, on-site landfill. Further, the Pete Units 1, 2, and 4 (and HSS Unit 7 FGD prior to conversion to natural gas), produce commercial grade gypsum from FGD operations that can be beneficially used for wallboard manufacturing, cement manufacturing, and agricultural use. In general, ash management activities did not changed for several years.

On April 17, 2015, EPA published the final Coal Combustion Residuals ("CCR") Rule, which regulates CCR as non-hazardous waste under Subtitle D of the Resource Conservation and Recovery Act ("RCRA"). The CCR Rule establishes national minimum criteria for existing CCR surface impoundments (ash ponds), including location restrictions, structural integrity, design and operating criteria, groundwater monitoring and corrective action, closure requirements and post closure care. Failure to demonstrate compliance with the national minimum criteria results in the requirement to cease use of and close existing active ponds within five years, with some potential for extensions, as needed. In 2016, the Water Infrastructure Improvements for the Nation ("WIIN") Act authorized states to establish CCR permitting programs and required EPA to establish a program for states that do not adopt one. On July 30, 2018, EPA finalized Phase One Part One CCR Rule Amendments in response to CCR litigation settlement and the WIIN Act. The revisions extended the deadline to cease placement of waste and commence closure of certain existing surface impoundments to October 31, 2020, established health-based groundwater protection standards for constituents with no Maximum Contaminant Levels, and added certain authorizations for Participating State Agencies or US EPA. EPA has proposed two additional revisions to the CCR Rule published on August 14, 2019 and December 2, 2019, respectively primarily to address matters at issue in litigation associated with the CCR Rule.

IPL Petersburg was unable to successfully demonstrate compliance with certain safety factor requirements set forth in the CCR rule at Petersburg, which are required to maintain operation of the ponds. As a result, IPL has removed the ponds from service, and made modifications to handle the material that was previously sent to the ash ponds. Specifically, as approved in Cause No. 44794, IPL installed a closed-loop bottom ash handling system to dewater the bottom ash which would otherwise have been sluiced to the active ponds.

IPL Harding Street and Eagle Valley have ceased coal combustion and must close their ponds in accordance with applicable local, state, and federal regulations. These ponds are currently being used on a very minimal basis to manage water not related to coal combustion.

IPL Petersburg, Harding Street and Eagle Valley Stations are collecting groundwater monitoring data as required by the CCR Rule. The data indicates exceedances of certain groundwater protection standards in the groundwater on IPL's property. As a result, IPL has completed Corrective Measures Assessment reports and is currently in the process of evaluating nature and extent. IPL will hold a public meeting prior to selection of a remedy. Any remedy selected will be protective of human health and the environment and will ensure that groundwater protection standards are achieved. Post-closure groundwater monitoring results could be different than past results due to the benefit of a waterproof cap included in IPL's ash pond closure plans[23]. IPL's closure plans include installation of a 30-inch protective layer over a waterproof liner on the pond preventing rainwater from carrying coals ash constituents into groundwater. Additionally, six inches of top soil will be laid on top and seeded with vegetative cover.

6.3 Pending and Future Environmental Regulations

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

There are a number of environmental initiatives that are being considered at the federal level that may impact the cost of electricity. This includes, but is not limited to more stringent regulations requiring:

- Additional SO_2 emission reductions;
- Additional NO_x emissions reductions;
- More stringent CCR requirements.

6.3.1 National Ambient Air Quality Standards

As discussed above, NAAQS are routinely reviewed, and potentially lowered by EPA. It is also possible that revised NAAQS may result in future revisions to CSAPR. As a result, future required reductions of SO_2 and NO_x are possible.

6.3.2 Coal Combustion Residuals

EPA is in the process of developing amendments to the 2015 CCR Rule. It is possible that these amendments could change the impact of the Rule on IPL. However, it is too early to determine the potential impact. Corrective actions or remedies related to the CCR Rule would occur regardless of a generating station's operating scenario as these costs would be related to remedies for impacts related to ash ponds which are being phased out.

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[23] IPL submitted Ash Pond Closure Plans for IPL Harding Street and Eagle Valley Stations to IDEM in 2016 which are under review. IPL Petersburg's Ash Pond Closure Plan was approved by IDEM in 2013.

6.3.3 Selenium Water Quality Criteria

On July 13, 2016, EPA published the final updated chronic aquatic life criterion for the pollutant selenium (Se) in freshwater per Clean Water Act section 304(a). The 2016 criterion is based on aquatic life selenium toxicity driven by organisms consuming selenium-contaminated food rather than by being exposed only to selenium dissolved in water. The revised criterion is a recommendation to states authorized to establish water quality standards under the Clean Water Act. Selenium criterion is expressed as four elements: fish egg-ovary, fish whole body or muscle, water column monthly, and water column intermittently. The federal rule will be implemented after the Indiana Department of Environmental Management finalizes the proposed Metals Criteria Revisions Rule. These final revised criteria will be incorporated into NPDES permits with compliance schedules in some cases. Currently, uncertainty remains around impacts to IPL.

6.3.4 New Source Review ("NSR")

In October 2009, IPL received a Notice of Violation and Finding of Violation (NOV) from the United States Environmental Protection Agency (EPA) under Section 113(a) of the Clean Air Act (CAA). The NOV alleges violations of the CAA at IPL's three primarily coal-fired electric generating facilities at the time, dating back to 1986. The alleged violations primarily pertained to the Prevention of Significant Deterioration (PSD) and nonattainment New Source Review requirements under the CAA. On October 1, 2015, IPL received an NOV from EPA alleging violations of opacity requirements at IPL Petersburg Unit 3 under the CAA, Indiana State Implementation Plan (SIP), and Petersburg Title V operating permit. Also, on February 5, 2016, the EPA issued a NOV alleging violations of PSD, non-attainment New Source Review and other CAA regulations, the Indiana SIP, and the Petersburg Title V permit.

Since receiving these NOVs, IPL management has met with staff from EPA and the Department of Justice (DOJ) to discuss a possible settlement of the NOVs. Settlements of similar claims have required companies to pay civil penalties, install additional pollution control technology on coal-fired electric generating units, retire existing generating units, and invest in additional environmental projects. At the time of this filing, IPL is now close to concluding a settlement to resolve the NOVs, pending required approvals by management at EPA and DOJ. Unless and until a settlement is approved and made public by DOJ, the discussions and proposed terms are confidential. By law, the settlement would be in the form of a judicial consent decree, and thus if approved by EPA and DOJ, any settlement would be subject to a public comment period and would have to be reviewed and approved by a federal district court judge before it would be final and effective

6.4 Summary of Potential Impacts

These regulations would potentially require IPL to incur additional expenses for compliance in the future. Figure 6.3 provides a summary of these potential regulations including potential timing and preliminary cost estimates available at this time.

Figure 6.3 | Estimated Cost of Potential Environmental Regulations

Rule	Expected Implementation Year	Capital Cost Range Estimate ($MM)	Assumed Technology
CWIS 316(b)*	2022	$13.8	Modified traveling screens
ELG	2018	$0	None
ACE Rule	2024	$8-27	Varies across portfolio

Section 7: Resource Portfolio Modeling

170 IAC 4-7-4(11) 170 IAC 4-7-4(22) 170 IAC 4-7-8(a)

Key Highlights
• IPL utilized the Ascend Analytics' PowerSimm modeling platform to develop a robust stochastic capacity expansion and production cost modeling framework • Systematic evalution of coal unit retirements modeled across a wide range of futures provided insight into coal unit viability now and in the future • Fundamentals-based forward curves from Wood Mackenize, a global market intelligence leader, provided a fresh look at forward-looking factors that could shape power and fuel markets • Deterministic sensitivities for key variables performed to stress portfolios and identify the impacts on sources of future uncertainty

7.1 Modeling Overview for the 2019 IRP

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

After the 2016 IRP, IPL engaged in a comprehensive review of modeling capabilities, processes, and tools to prepare for the 2019 IRP. The 2019 IRP modeling process is a culmination of two years of work and process improvement from assumption development to the model itself. Figure 7.1 summarizes modeling done in 2016 versus 2019.

Figure 7.1 | Modeling Comparison: 2016 IRP vs. 2019 IRP

2016 IRP Modeling	2019 IRP Modeling
Six (6) candidate portfolios created from scenarios with deterministic, "typical week" capacity expansion runs	Fifteen (15) candidate portfolios created from stochastic capacity expansion runs with 8760 chronological commitment and dispatch across 100 iterations varying weather, load, and commodity prices
Six (6) deterministic production cost runs with base case assumptions	Seventy-five (75) stochastic production cost runs for each scenario with deterministic scenario drivers (15 portfolios * 5 scenarios)
One (1) 50 iteration stochastic study with base case assumptions	Each scenario conducted stochastically with 100 iterations to widen the range of uncertainty considered. A combined total of 7,500 iterations across all model runs.
Two (2) deterministic sensitivities for one portfolio (Base Case) on timing and magnitude of Clean Power Plan	Four (4) deterministic sensitivities for two scenarios and all portfolios evaluating (1) renewable and storage capital costs, (2) capacity prices, (3) wind capacity factors, and (4) wind LMP basis.

7.2 Modeling Tools

170 IAC 4-7-4(5) 170 IAC 4-7-4(19) 170 IAC 4-7-4(28)

IPL began a transition to Ascend Analytics' PowerSimm software in mid-2017. The PowerSimm platform provides a comprehensive suite of modeling products that cover short-term optimization (1-14 days) and long-term planning (20+ years).

IPL used three PowerSimm modules for the 2019 IRP:

PowerSimm Module #1: Automatic Resource Selection ("ARS")

ARS is the capacity expansion module in the PowerSimm platform that allows utilities to perform long-term resource optimization and selection subject to a set of constraints. ARS uses hourly dispatch modeling to make optimal resource decisions across the planning horizon subject to constraints. ARS used mixed integer programming (MIP) techniques to optimize resource decisions, with the objective of minimizing the present value of portfolio costs, subject to physical and financial constraints. The differentiating factor of PowerSimm is the ability to perform stochastic capacity expansion to provide a robust plan across a wide range of futures.

PowerSimm Module #2: Portfolio Manager

Portfolio Manager is the mid-term production cost module that was the foundation of the hourly portfolio runs. The back-end dispatch optimization, forward curve simulation, renewable simulation, and load simulation are the same as ARS and are run through the same software. Optimized portfolios from ARS were created as distinct portfolios in Portfolio Manager, which gave us the full reporting functionality required for the portfolio comparison and metric evaluation.

PowerSimm Module #3: BatterySimm

The BatterySimm module enables dynamic, hourly and sub-hourly optimization in PowerSimm. This was effectively a back-end code enhancement that conducted the hourly optimization of storage separately in a GAMS-based model and seamlessly integrated the results for ARS and Portfolio Manager. IPL did not use sub-hourly modeling in the 2019 IRP, but sub-hourly modeling is being explored as an improvement for future IRPs.

IPL also used a spreadsheet financial model to calculate PVRR for the 2019 IRP:

Financial Model outside of PowerSimm

IPL utilized a spreadsheet-based set of financial models to build the revenue requirement. The revenue requirement calculation outside of PowerSimm provides a transparent, flexible method to calculate PVRR, compare scenarios and portfolios, and build customized outputs for stakeholders. Consultants with Concentric Energy Advisors helped develop the model, linked the PowerSimm results to the financial model, and created a set of quality control measures to validate information was accurately linked.

In previous IRPs, PVRR was an output of the model, and it was difficult to trace the individual components to see how it was calculated. This methodology provides a set of transparent modeling files and provides a tool for performing other sensitivities on the portfolios. This allows greater visibility into the modeling and provides transparency to IPL stakeholders.

7.3 Modeling Framework

170 IAC 4-7-4(5)

7.3.1 Retirement Analysis

The modeling framework in the 2019 IRP centered on a systematic evaluation of IPL's existing resources compared with alternatives. IPL evaluated a set of fixed retirement dates on the Petersburg units based on age, existing technology, expected maintenance, and cost.

Most capacity expansion models, including PowerSimm, have the capability of co-optimizing new build decisions with retirement decisions for existing resources. This type of optimization can be useful, but it introduces modeling complexities and forces the modeler to make up front decisions about constraints for retirements.

IPL established the retirement dates instead of allowing the model to select dates for several reasons:

1. **Fixed cost allocation**: Petersburg is a large plant with interconnected systems and processes. As a result, allocating fixed costs to specific units presents a challenge because the model cannot dynamically evaluate changes to fixed costs as a result of the order of retirements. The timing and order of retirements, if any units are selected for retirement, would require an iterative modeling process that could quickly increase the number of required runs.
2. **Capacity valuation and Reserve Margin Constraints**: IPL's net long capacity position creates unique challenges for capacity expansion modeling. PowerSimm, like other models, is designed to find the lowest cost portfolio by maximizing resource profitability (total revenue minus total cost) subject to meeting a set of specified constraints. The PowerSimm model is designed to impose a "penalty" to portfolios that exceed the reserve margin target or are short of the reserve margin target. Because IPL is long 300 – 400 MW for our "going in" position, the model could prematurely retire units to avoid exceeding the reserve margin target. Allowing the model to "overbuild" in order to compensate for this could result in more capacity being selected than needed.
3. **Stakeholder input**: IPL received several requests to evaluate retirement of the entire plant by at least 2030, and in some cases sooner.

Several factors helped IPL establish the decision window on retirement dates of the coal units:

- **Unit Age:** Petersburg Units 1 and 2 are 52 and 49 years old, respectively, and have age-based retirement dates of 2033 and 2035. Costly unit overhauls and maintenance are required on the units to maintain performance and safety targets, so IPL wanted to evaluate the economics of the ongoing, all-in costs and net benefits of operating those units through the early 2030s compared to alternatives.
- **Renewable Tax Credits**: the pending phase out of the PTC and ITC also provided a short-term action window in which to evaluate retirement dates.
- **Scale and Timing of Replacement Capacity**: even if IPL let the model co-optimize retirement dates of existing resources with new resources, we would still need to constrain the model to generate portfolios that are reasonable and provide enough time for IPL to build, acquire, or contract for replacement capacity. We identified retirement dates for Pete 3 and 4 based on expectations for the lead time to integrate replacement capacity on the scale of those units.

This modeling framework allowed IPL to effectively evaluate a range of transition portfolios across a wide range of futures while clearly defining key drivers of portfolio risk and opportunity. The probabilistic nature of the model combined with scenario analysis and targeted sensitivities on key variables led IPL to a well-defined decision framework.

Figure 7.2 | IRP Portfolios with Retirements

Portfolio	Description
Portfolio 1	No Early Retirements
Portfolio 2	Pete Unit 1 Retire 2021 Pete Units 2-4 Operational
Portfolio 3	Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational
Portfolio 4	Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational
Portfolio 5	Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030

7.3.2 Scenarios

170 IAC 4-7-4(26)

In the 2019 IRP, IPL set out to define a set of high-impact drivers to define scenarios rather than focus on narrative-themed scenarios as done in the 2016 IRP. The scenarios developed and presented in the second public stakeholder meeting in March 2019 provide a range of futures with variations and combinations of three key variables: natural gas prices, potential carbon legislation, and load forecasts.

All scenarios were modeled stochastically, which means that volatility was applied probabilistically to the forecasts in each specific scenario. The combination of scenarios with deterministic drivers and stochastic production cost modeling widens the range of uncertainty considered and enables us to fully account for risk and uncertainty as part of the modeling process. Figure 7.3 contains a description of the scenarios in the 2019 IRP and the key drivers for each scenario.

Figure 7.3 | IPL 2019 IRP Scenarios and Drivers

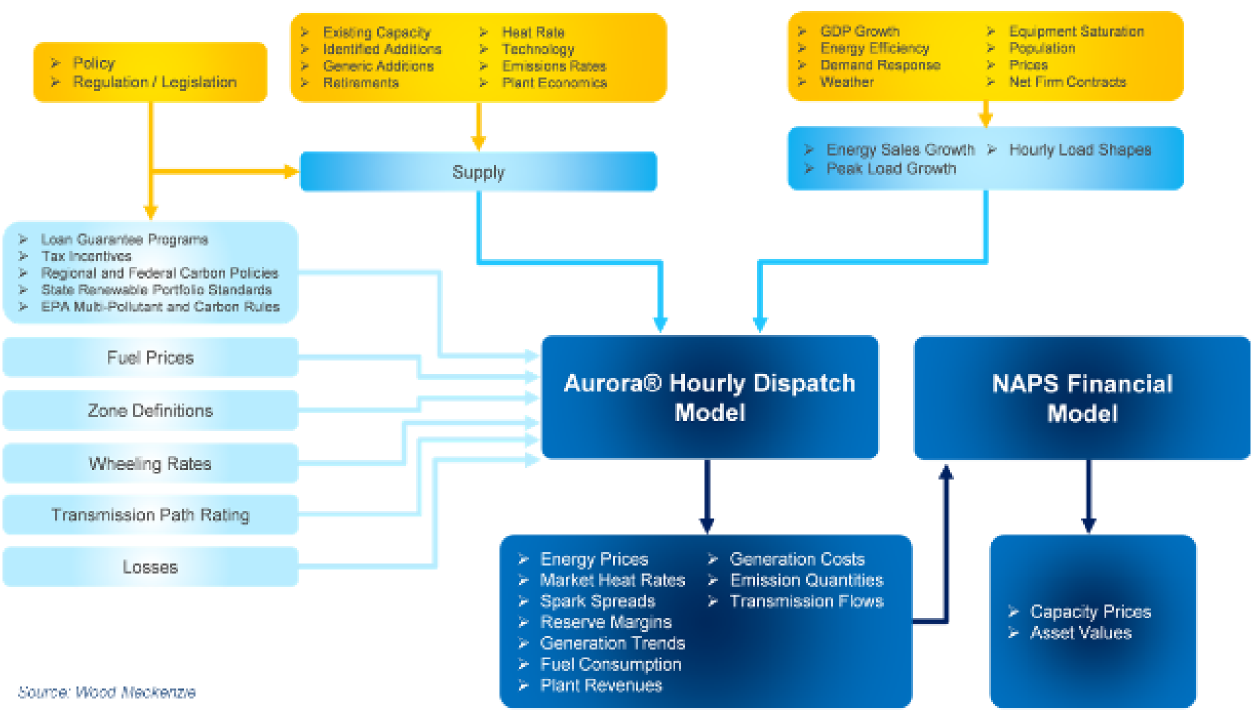
	Reference Case	Scenario A: Carbon Tax	Scenario B: Carbon Tax + High Gas	Scenario C: Carbon Tax + Low Gas	Scenario D: No Carbon Tax + High Gas
Natural Gas Prices	Base	Base	**HIGH ↑**	**LOW ↓**	**HIGH ↑**
Carbon Tax	No Carbon Price	**Carbon Tax (2028+)**	**Carbon Tax (2028+)**	**Carbon Tax (2028+)**	No Carbon Price
Coal Prices	Base	Base	Base	Base	Base
IPL Load	Base	Base	Base	**LOW ↓**	**HIGH ↑**

Capital Costs for Wind, Solar, and Storage	Base	Base	Base	Base	Base

IPL utilized the 2018 H1 Wood Mackenzie Long Term Outlook for the 2019 IRP. Wood Mackenzie's North American Power & Renewables Service provides a forward view using their fully integrated fundamentals-based forecast. The detailed power market analysis covers all NERC regions and includes deliverables on supply, demand, generating fuel pricing, wholesale power price projections, and analysis of other key fundamental drivers. In addition to the core forecast cases, Wood Mackenzie provided a set of natural gas sensitivities to IPL for use in the IRP.

Wood Mackenzie's two core cases are fully optimized cases – this means that they conducted a full zonal, hourly unit commitment and dispatch and capacity expansion to develop the underlying resource mix and market prices. Figure 7.4 contains a flow chart for Wood Mackenzie's North American fundamental modeling process.

Figure 7.4 | Wood Mackenzie North America Model



Source: Wood Mackenzie

Detailed reports on the H1 2018 Long Term Outlooks from Wood Mackenzie can be found in Confidential Attachments 7.1, 7.2, 7.3, 7.4, and 7.5.

Reference Case

The Reference Case is based on the Wood Mackenzie H1 2018 "No Federal Carbon Case". This fully optimized case represents the absence of any federal carbon policy but contains a forward-looking view on the underlying fundamentals of fuel, renewable, and power markets.

Scenario A: Carbon Tax Case

The Carbon Tax Case is based on the Wood Mackenzie H1 2018 "Federal Carbon Case" underlying assumptions. This includes a federal carbon tax of $2.45/ton starting in 2028 and escalating to $36/ton by 2039.

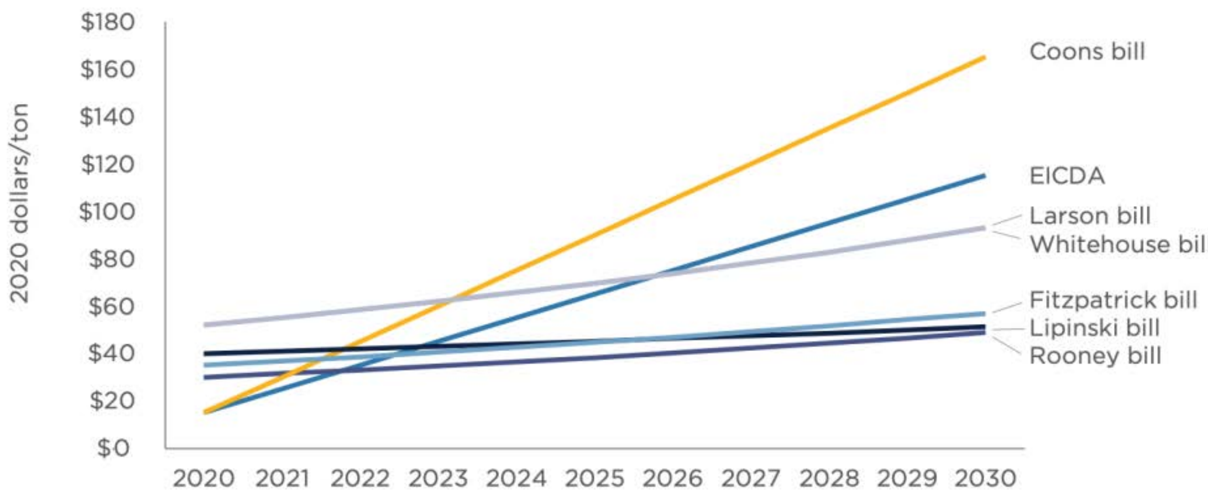
Wood Mackenzie's narrative on the Carbon Tax Case is as follows:

> Despite dim prospects for any federal carbon regulation under the current administration, broad-based sustainability efforts are likely to create a push towards a carbon framework in the US. We assume this does not materialize into policy goals until 2028, reflecting political inertia that has hounded any such policy efforts. Specifically, legislative proposals start emerging by 2022, and then it takes years before laws are passed with actual implementation goals set for 2028. Source: Wood Mackenzie

IPL recognizes the uncertainty surrounding any assumption for future carbon legislation. The timing, scale, and structure of any price on carbon is difficult to forecast. At the time this report was developed, seven different carbon tax legislative proposals have been introduced to Congress in 2019. Figure 7.5 shows a summary of the carbon prices proposed in these bills. Each bill has a different structure and timeline, and there are significant political headwinds facing these bills until after the 2020 Federal Election.

IPL believes that including a federal price on carbon in scenarios is a prudent planning exercise considering the national and global efforts for carbon reduction. Carbon legislation has an outsized impact on the electric power sector and ignoring the potential for future carbon pricing could introduce significant risk to IPL customers.

Figure 7.5 | Snapshot of Carbon Prices in Bills Introduced to Congress in 2019[24]



Source: CGEP analysis

Scenario B: Carbon Tax Case + High Gas

The Carbon Tax Case plus High Gas scenario is a natural gas sensitivity case provided by Wood Mackenzie. The high gas sensitivity includes a natural gas price forecast that is 30-40% higher than the base forecast, and power prices were developed by Wood Mackenzie through their fundamental model. Factors that could lead to this scenario:

- Increased regulation on fracking and natural gas production, which could include regulations on methane and/or water regulation
- A carbon tax driving more demand for natural gas as a "bridge fuel" to firm up intermittent renewable resources
- Higher than expected natural gas exports driving higher demand and prices for natural gas

Scenario C: Carbon Tax Case + Low Gas + Low Load

The power and natural gas prices in this case are from a sensitivity from Wood Mackenzie on their Federal Carbon Tax Case. This scenario also includes a low load forecast for IPL. Factors that could lead to this scenario:

[24] https://energypolicy.columbia.edu/sites/default/files/file-uploads/EICDA_CGEP-Report.pdf

- Carbon legislation combined with a national effort to decarbonize the grid could push out incremental natural gas power plant build as storage and other firm resources fill the gap from coal. This decrease in demand could drive prices lower
- Worldwide shifts toward renewables lowers demand for U.S. LNG exports, resulting in a glut of natural gas
- Overall lower power demand due to economics and energy efficiency results in less power demand for natural gas

Scenario D: No Carbon Tax Case + High Gas + High Load

Natural gas and power prices were from a Wood Mackenzie high gas sensitivity run on their No Carbon Tax Case. This scenario also includes a high IPL load forecast.

Factors that could lead to this scenario:

- Global demand for natural gas could increase U.S. LNG exports beyond current forecasted trajectories.
- Despite a lack of federal carbon legislation, market economics, the desire for decarbonization, and accelerated renewable deployment drives demand for natural gas power plant development as a replacement for coal.
- A change in administration in the 2020 election results in increased regulation on natural gas production, but comprehensive carbon legislation remains stalled at the federal level.

7.3.3 Fundamental Forecasts

The fuel prices for IPL's existing generating units can be found in Confidential Attachment 7.6.

Power Prices

Wood Mackenzie forecasts for MISO Indiana Hub were utilized in all the IRP models. Through 2024, a blend of forward curves and fundamental curves was used for both power and natural gas, as noted in Figure 7.6. Starting in 2024, the fundamental curves were used in the model.

Figure 7.6 | Illustrative Example: Forward Curve and Fundamental Forecast Blend

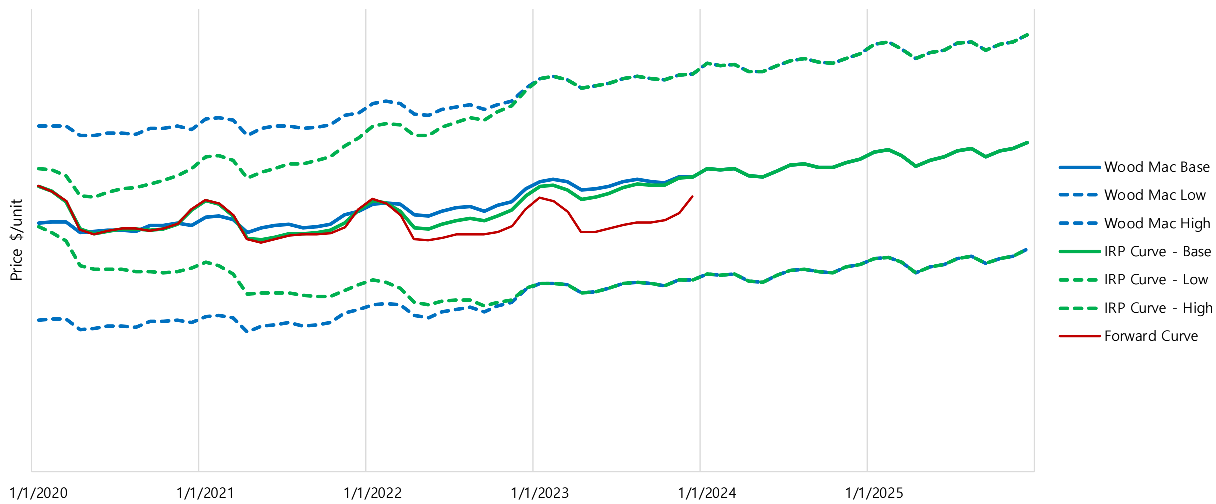
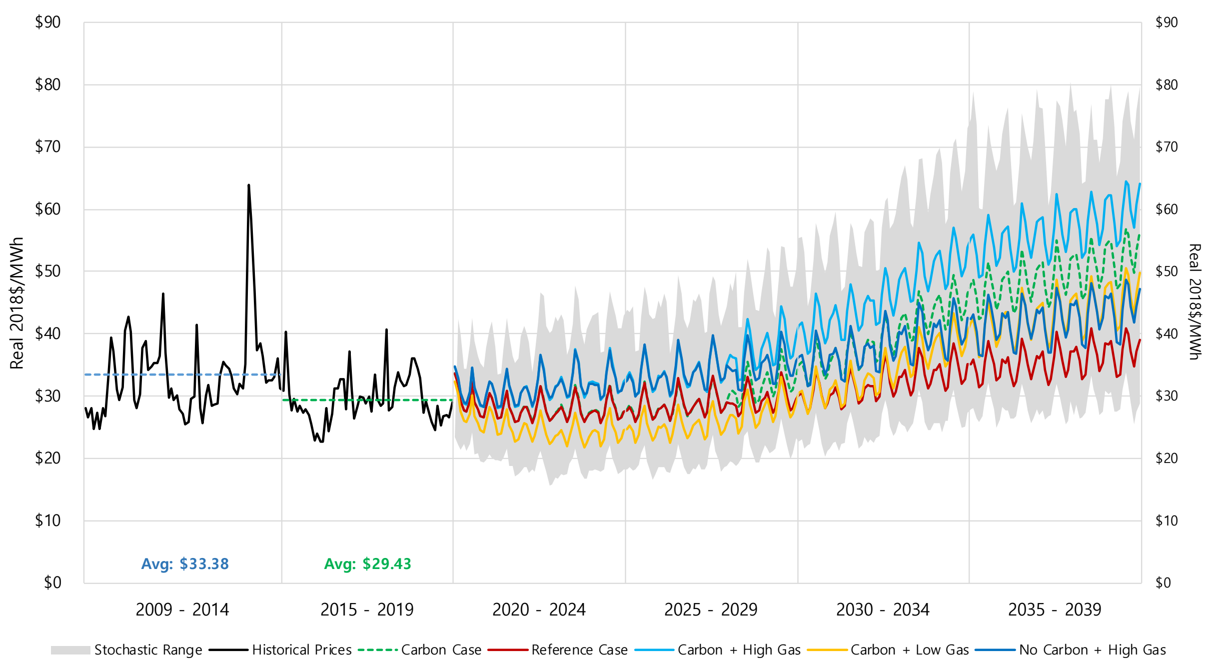


Figure 7.7 shows the distribution of 7x24 power prices in the 2019 IRP. The stochastic range shown is the difference between the 95th and 5th percentiles for all modeled scenarios, and the base curve for each scenario is also shown.

Figure 7.7 | MISO Indiana Hub 7x24 Power Prices in 2019 IRP (2018$/MWh)



IPL also included a locational marginal price (LMP) basis adjustment to existing and new supply-side resources (Figure 7.8). In the model, market revenues for supply-side resources are a function of the energy production and the wholesale market price, represented by market locational marginal prices (LMPs) in that hour. In MISO, LMPs at individual nodes can separate due to congestion, which is caused when transmission constraints cause re-dispatch of units that raises system production costs. To more accurately reflect the locational aspect of resources, IPL included an estimate for the LMP basis differential for existing and new resources. Forecasting congestion is difficult and is subject to uncertainty. A detailed congestion study will be conducted for any actual projects that IPL pursues.

Figure 7.8 | Modeled LMP Basis from MISO Indiana Hub

	On-Peak	Off-Peak
IPL Load	-2%	-1%
Petersburg	-9%	-6%
Eagle Valley	-5%	-4%
Harding Street	-3%	-2%
Georgetown	-2%	-1%
IPL Existing Solar	0%	0%
Hoosier Wind Park	-20%	-18%
Lakefield Wind	-21%	-21%
New Combined Cycle	-5%	-4%
New Gas Peaker	-3%	-2%
New Wind	-20%	-18%
New Solar	0%	0%
New Storage	0%	0%

IPL receives Annual Revenue Rights (“ARRs”) from historical generator locations from MISO. ARRs were designed to compensate owners of transmission lines from generators to their load for the use of the transmission system with the advent of open access and the formation of MISO. ARRs can be monetized in the Annual Financial Transmission Right (FTR) auction or ARR holders can convert all or a portion of their ARRs into FTRs whose value will “float” in the Day-Ahead market throughout the planning year. IPL assumed that ARRs are retained in all retirement scenarios, which is consistent with the MISO Business Practice Manual for FTRs, and that the value of ARRs does not change when units are retired. The value of the ARRs was the same in all portfolios and scenarios and therefore was not included in the revenue requirement calculation. IPL will continue to value ARRs and optimize the value of ARRs and FTRs to the customer’s benefit through time and will adjust strategies and valuations accordingly to changes to the underlying fundamentals of the system.

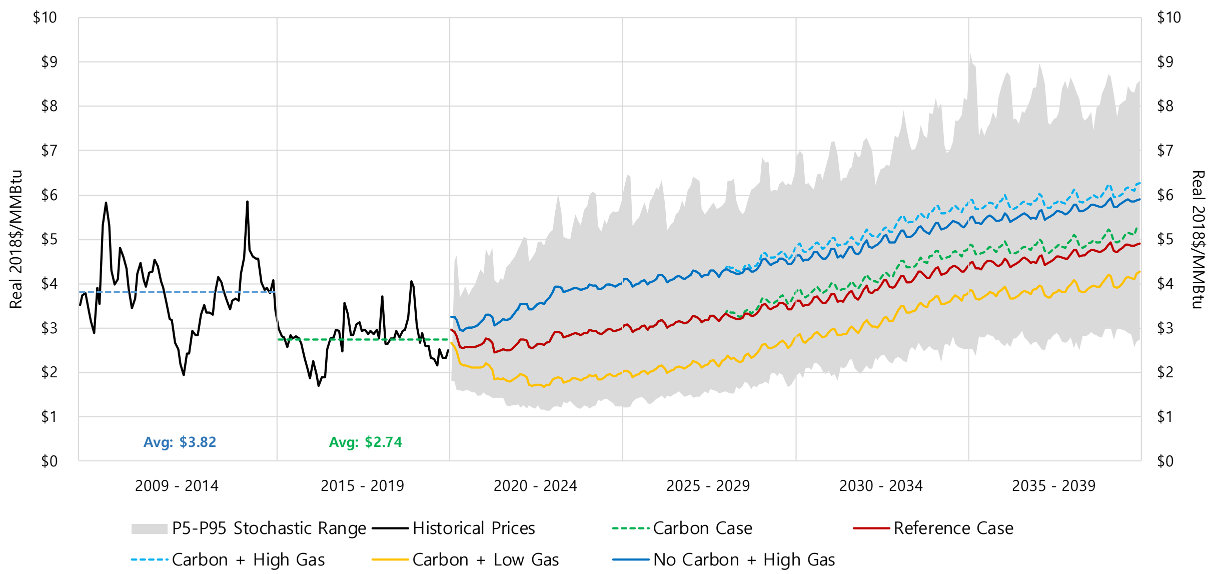
A sensitivity analysis was conducted to estimate the impacts of an improved basis assumption for new wind assets. This analysis is described in Section 7.4.4, and results are shown in Section 8.4.4.

Natural Gas Prices

Figure 7.9 contains the modeled range of natural gas prices in the 2019 IRP. Henry Hub was the benchmark used for simulations, and a basis or delivery adder or discount was included for existing resources as well as any new natural gas resources.

The fuel prices for IPL's existing generating units can be found in Confidential Attachment 7.6.

Figure 7.9 | Henry Hub Natural Gas Prices



Carbon Prices

For scenarios with a carbon tax, a price on carbon was included in the model and is added to the variable dispatch cost of thermal units. To the extent thermal units are economically dispatched in these scenarios, carbon emissions are a cost that is reflected in the PVRR calculation. Figure 7.10 contains an illustrative example of how different levels of a carbon tax impact the variable cost of a typical coal plant and a typical combined cycle plant.

Figure 7.10 | Carbon Price Impact on Dispatch Cost

Carbon Price ($/ton)	Increase in Variable Cost ($/MWh) Coal Plant*	Natural Gas Combined Cycle**
$2	$2	$1
$5	$5	$2
$10	$11	$4
$20	$22	$8
$40	$43	$17

* 10.5 MMBtu/MWh heat rate, 206 lb/MMBtu CO_2 emission rate

** 7.0 MMBtu/MWh heat rate, 119 lb/MMBtu CO_2 emission rate

Figure 7.11 depicts the carbon price curve utilized in Scenarios A, B and C.

Figure 7.11 | Federal U.S. Carbon Price in Carbon Scenarios

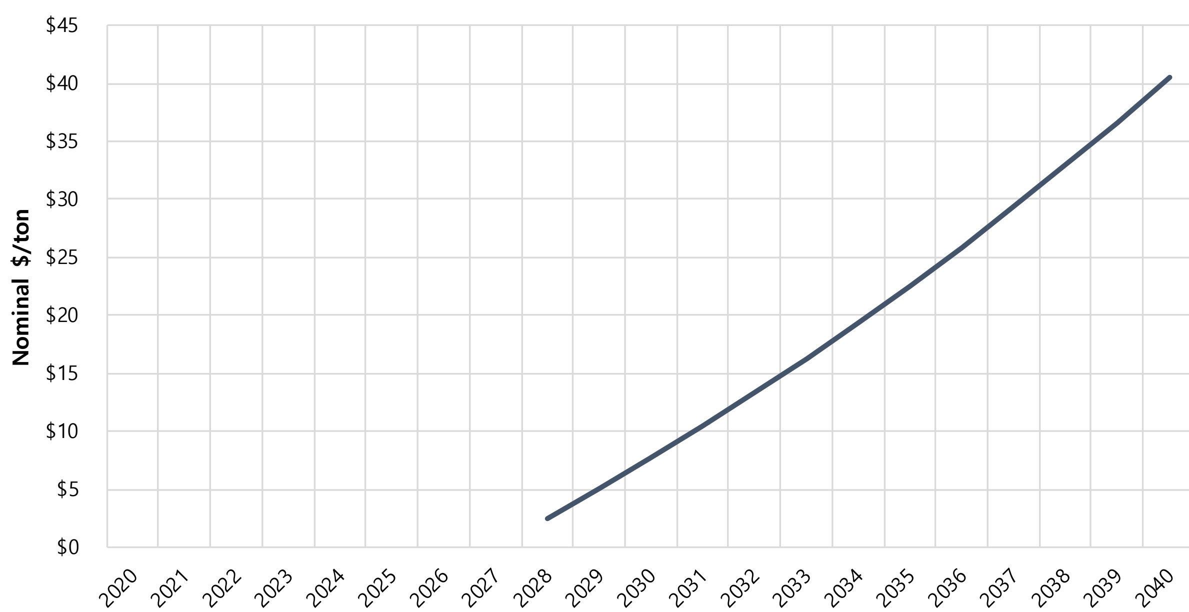
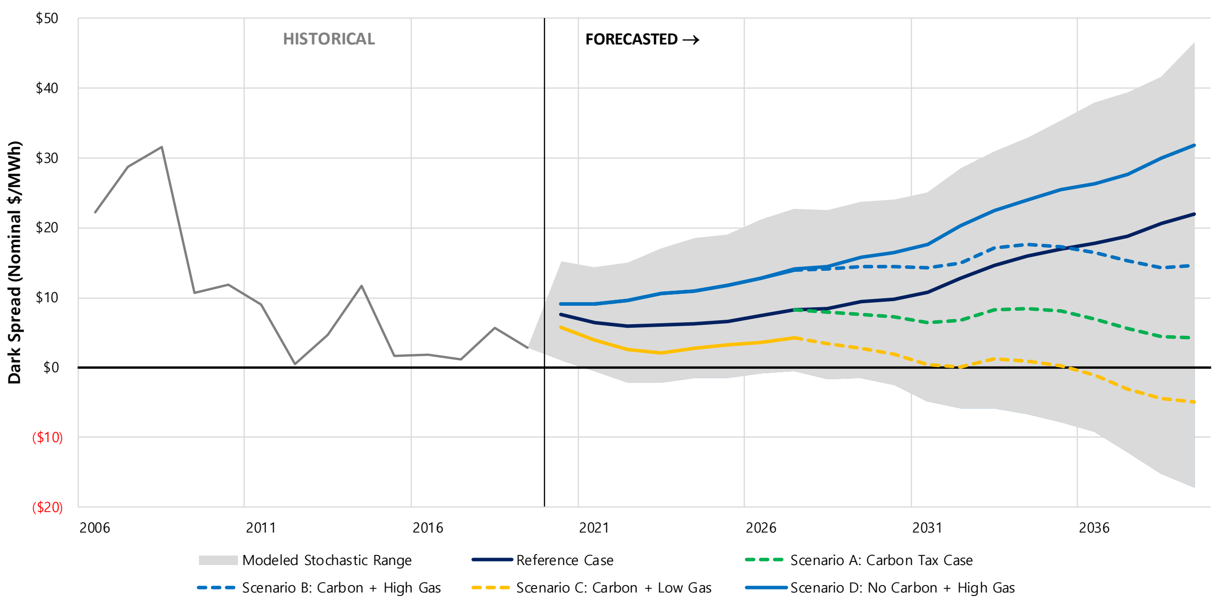


Figure 7.12 shows the distribution of 7x24 clean dark spreads[25] for the base curves from each scenario included in the IRP. The dark spread, which is the market power price minus the variable production cost, is indicative of the economic positioning of coal in MISO relative to other units. A dark spread of \$0/MWh means that market prices on average are at the cost of the coal unit's variable cost, so dispatch hours and therefore energy margin will be limited. In reality, dark spreads vary throughout the year, and the dispatch of the unit can change the captured or realized dark spread because it can cycle down or off during low price times and dispatch up during high price times.

As Figure 7.12 shows, the modeled scenarios captured a wide range of potential futures for underlying power price fundamentals that could impact coal's economic viability. A carbon price is a significant variable impacting dark spreads, and natural gas will continue to be a driver of risk and opportunity for coal assets in the short term and long term. In addition to this distribution represented by the scenarios, each scenario was modeled stochastically, so the range of uncertainty captured was expanded to more potential futures.

Figure 7.12 | IPL Petersburg 7x24 Clean Dark Spreads for Scenarios (Nominal \$/MWh)

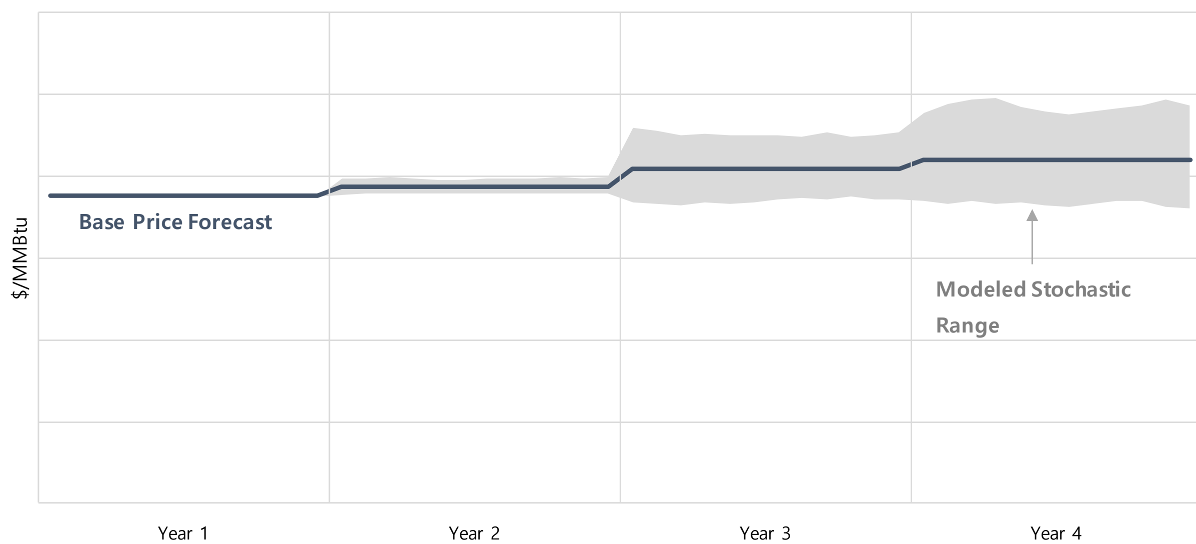


[25] Clean Dark Spread = Power Price – (Fuel Price * Heat Rate + Variable O&M + Emission Cost); does not contain market dispatch results, just 7x24 power prices with LMP basis and base variable costs per year of the analysis

Coal Prices

The coal curve for Petersburg is an internally developed curve based on contracted fuel positions, forward-looking analysis for spot market coal, and market intelligence for the Indiana coal market. Coal prices were modeled stochastically, with volatility applied to the base coal curve to simulate a range of prices that varied monthly. Any hedged or contracted coal was accounted for, which primarily affected the range of coal prices modeled in the early years of the study. Figure 7.13 contains an illustrative chart showing how contracted coal was accounted for in the stochastic simulations.

Figure 7.13 | Coal Price Volatility Tied to Hedge Percentage in Early Years of Study



The fuel prices for IPL's existing generating units can be found in Confidential Attachment 7.6.

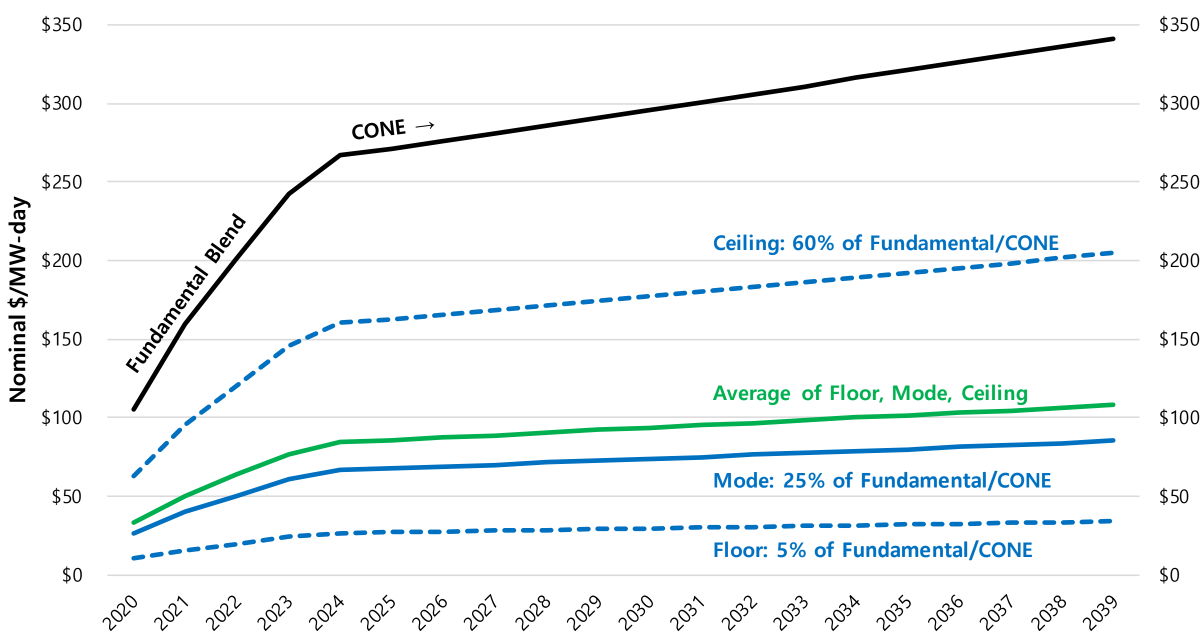
Capacity Prices

MISO runs a voluntary, administrative capacity auction process called the Planning Resource Auction ("PRA"). The MISO capacity market is a residual market for balancing prompt year capacity positions, as opposed to a long-term capacity construct like PJM's three-year forward market. Because of the residual nature of MISO's capacity construct, there has historically been volatility in both the auction clearing prices as well as the bilateral market. IPL chose to account for this uncertainty by simulating a range of capacity prices stochastically using a triangular distribution. The minimum, mode, and maximum values were established as percentages of the fundamental forecast, which approaches the Cost of New Entry ("CONE") for a combustion turbine by 2024.

Figure 7.14 contains a graphical depiction of this modeling setup. For each year of the study, the average of all simulated prices will equal the average of the minimum, mode, and maximum values established. The value of capacity only applies to portfolio imbalances, meaning capacity purchases and sales. For example, IPL's "going-in" capacity position is a net long capacity position of approximately 400 MW. The net capacity length in MW is multiplied by the annual capacity price in each iteration and valued as a net revenue in the revenue requirement calculation.

In addition to this modeling approach, we also ran deterministic sensitivities on the capacity price for each portfolio for the Reference Case and Carbon Tax Case. The setup is in Section 7.4.2, and results are in Section 8.4.2.

Figure 7.14 | MISO Zone 6 Capacity Price Range



Load

Base, low, and high IPL load forecasts were used in the scenarios. The Reference Case, Scenario A, and Scenario B used the base forecast. Scenarios C and D introduced low and high load forecasts in combination with other scenario drivers. PowerSimm uses weather simulations to create variation in load, and all load simulations are scaled to match forecasted levels and shaped hourly based on historical hourly IPL load data.

Candidate resource portfolios were created to meet the load obligation for the base load forecast. For the low and high load forecast scenarios, any incremental capacity shortfall was filled with capacity market purchases and excess capacity was sold at the modeled range of capacity prices.

Figure 7.15 and Figure 7.16 contain the modeled distribution of annual peak and energy forecasts for IPL.

Figure 7.15 | IPL Annual Energy Simulated Range and High/Low Cases

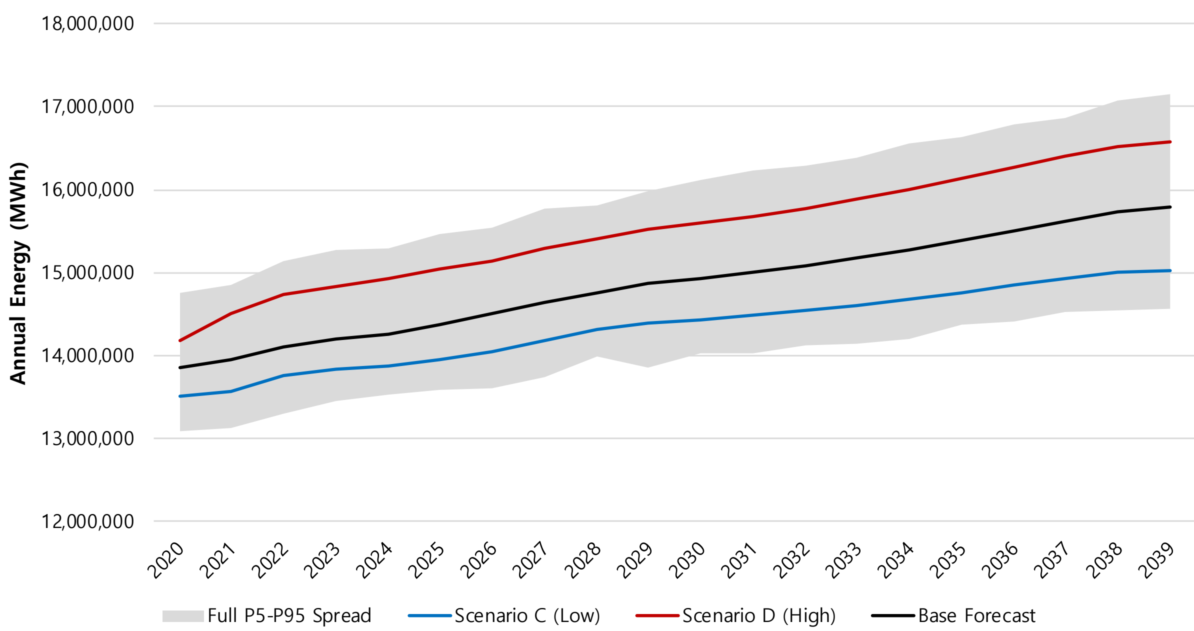
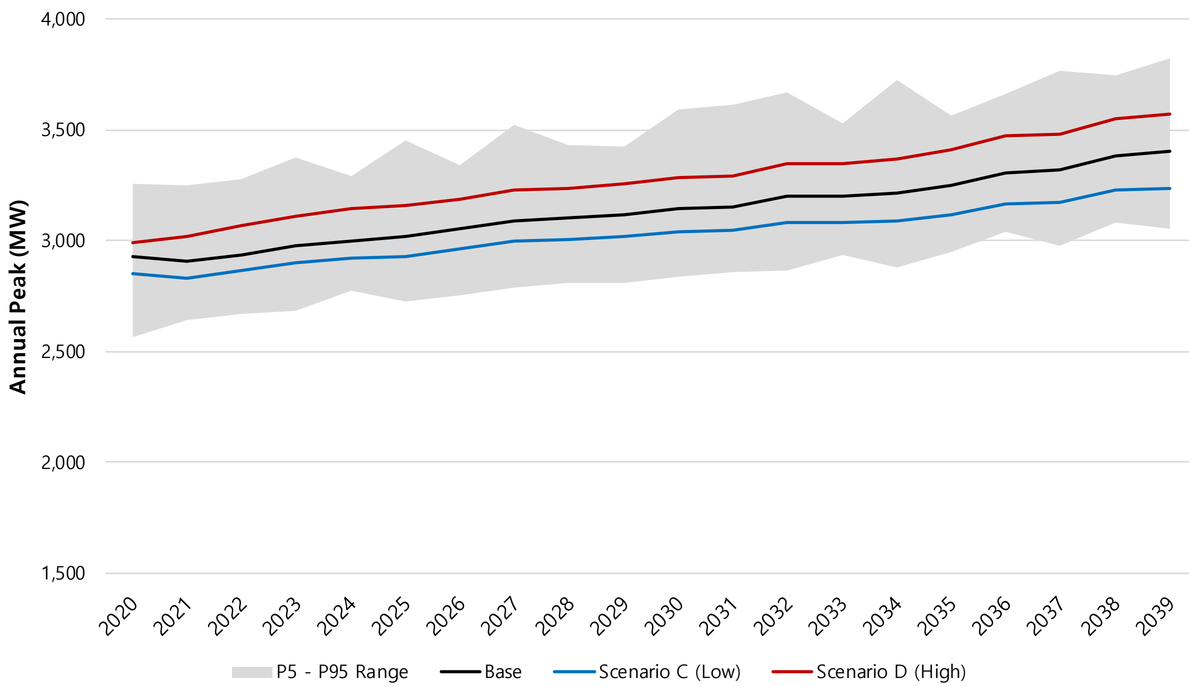


Figure 7.16 | IPL Annual Peak Load Simulated Range and High/Low Cases



7.3.4 Stochastic Parameters

This section describes the setup of the stochastic parameters required in all IRP models. The two primary inputs are volatility and correlation of key variables.

Volatility

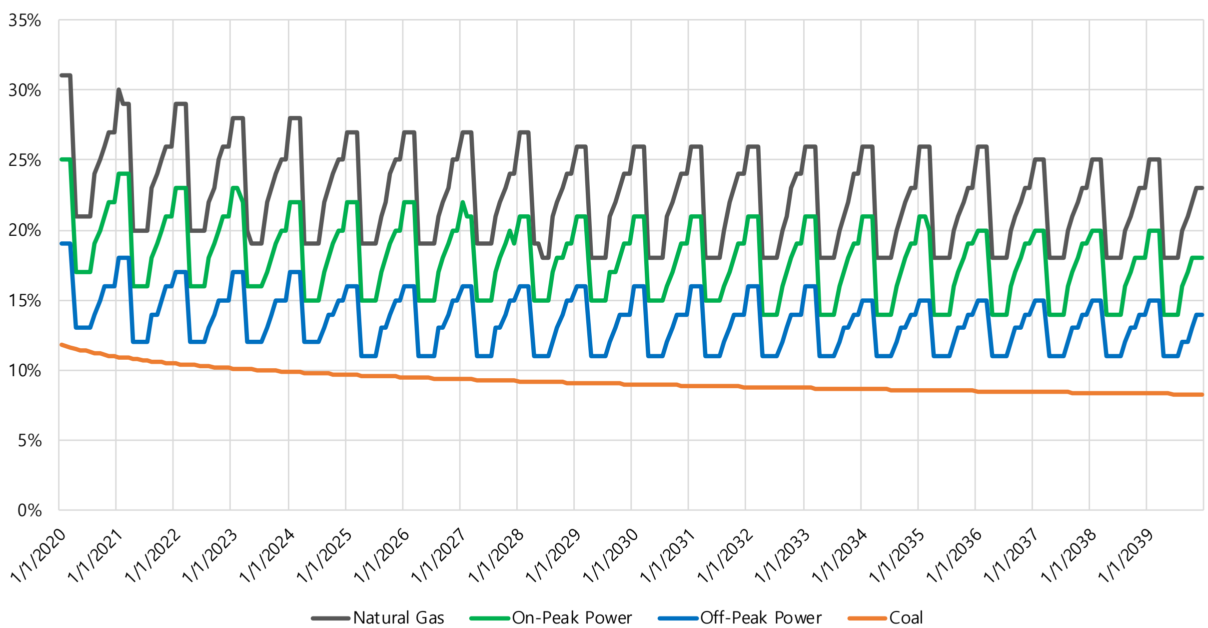
Volatility in the context of this type of modeling is defined as the annualized standard deviation of daily changes in forward market prices based on historical volatility of forward markets. Two dynamics are typically present when looking at forward-looking volatility measures: term structure and seasonality. A basic definition of the term structure of volatility is that volatility is typically higher the closer you are to contract expiration. This is driven by several factors, including the fact that closer contracts are more liquid and actively traded as well as the fact that short-term weather forecasts can drive sharper changes in power and gas markets more for the next month or two compared to 6 months or a year out. Seasonality is simply driven by more uncertainty in winter for natural gas, which therefore impacts power prices.

Volatility is used in the model to determine the range of outcomes, or the spread between the lowest and the highest priced iterations. A lower volatility input would result in a tighter range of prices, whereas higher volatility would result in a wider dispersion of outcomes.

Coal prices typically experience lower volatility on a forward-looking basis due to the nature of the commodity – the production cycle is longer, contracting is often longer term, and the transportation of the product is done on a longer time scale. Therefore, it takes longer for underlying market fundamentals to impact coal markets.

Figure 7.17 contains monthly volatility for natural gas, power, and coal that was used in PowerSimm. These volatility curves were used for all stochastic runs – this means that the volatilities stayed constant, but the underlying curves to which the volatilities were applied changed.

Figure 7.17 | Monthly Annualized Volatility for Gas, Power, and Coal in 2019 IRP



Correlation

The monthly correlation of forward prices is another input in PowerSimm for developing stochastic forward price ranges. The only correlation entered was for power and natural gas. The role of natural gas as a marginal fuel has long been observed, and as a result there has historically been a high correlation between natural gas prices and power prices on a monthly and daily basis.

IPL expects natural gas units to continue to drive the marginal price of power as more coal is retired, and therefore we included a high correlation (90%) for monthly power and natural gas prices. This correlation input only affects simulation of monthly forward power and gas prices – there is still separation of these commodities in the daily and hourly spot price simulations. The daily and hourly relationship between power and natural gas is preserved in the PowerSimm simulation framework.

In the 2018 State of the Market Report, the MISO Independent Market Monitor (IMM) describes the price-setting nature of natural gas and produced Figure 7.18 also presented in the report:

> *Price-Setting Shares.* Coal resources set system-wide prices in 46 percent of hours, down from 55 percent in 2017. Although natural gas units produce a modest share of the energy in MISO, they play a pivotal role in setting energy prices. Gas-fired units set the system-wide price in more than half of all intervals for the year, including almost all peak hours when prices are highest. In addition, congestion often causes gas-fired units to set prices in local areas when lower-cost units are setting the system-wide price. This is why they set local LMPs in 87 percent of intervals and why they are a key driver of energy prices.

Figure 7.18 | 2018 MISO State of the Market: Price-Setting by Fuel Type

	Unforced Capacity				Energy Output		Price Setting			
	Total (MW)		Share (%)		Share (%)		SMP (%)		LMP (%)	
	2017	2018	2017	2018	2017	2018	2017	2018	2017	2018
Nuclear	12,420	12,225	10%	10%	16%	16%	0%	0%	0%	0%
Coal	50,843	48,775	39%	38%	47%	46%	55%	46%	84%	78%
Natural Gas	55,794	55,240	43%	43%	23%	27%	44%	53%	85%	87%
Oil	1,904	1,691	1%	1%	0%	0%	0%	0%	0%	0%
Hydro	3,929	3,966	3%	3%	1%	1%	0%	1%	1%	1%
Wind	2,610	3,005	2%	2%	8%	8%	0%	0%	30%	31%
Other	2,273	2,678	2%	2%	4%	2%	0%	0%	4%	2%
Total	**129,773**	**127,580**								

Other studies also indicate a continued strong correlation between power and natural gas prices. The NREL *2018 Standard Scenarios Report*[26] evaluated the relationship between power and natural gas which led them to provide the following key insight:

> **Marginal electricity prices continue to be impacted primarily by natural gas prices.** The modeled scenarios showed a linear relationship between natural gas prices and marginal electricity prices across most scenarios. Scenarios with higher or lower renewable energy

[26] https://www.nrel.gov/analysis/standard-scenarios.html

deployment tended to impact the electricity prices by changing the demand for natural gas, which in turn impacts the price.

No correlation was included for forward coal prices. In the short- to mid-term (1-5 years), there is low correlation between coal and natural gas prices as coal markets do not typically respond as quickly to changes in gas prices. Over the long term there could be correlation between coal and natural gas, but it has not been a consistent historical trend and therefore was not included.

7.3.5 Capacity Expansion Setup and Constraints

The capacity expansion optimization was set up to find the lowest cost resources subject to meeting IPL's annual reserve margin constraint using the base load forecast. While load was simulated stochastically, this did not affect the reserve margin target.

Figure 7.19 contains modeled constraints for new supply-side resources. Constraints on the first year available and number of projects per year are based on expected timeline for construction and/or procurement of projects under development, including the time for regulatory approval.

Figure 7.19 | Supply-Side Resource Capacity Expansion Constraints

	Gas CC	Gas CT - Frame	Gas CT - Aero	Gas Recip	Wind	Utility Solar	4-Hour Battery Storage
First Year Available	2023	2023	2023	2023	2022 (2021 pricing)	2023	2023
Generic Project Size (ICAP MW)	325	100	126	108	50	25	20
Number of Projects Allowed Per Year	4	5	1	1	10 in 2022 4 in 2023+	20	20
MW Allowed Per Year	1,300	500	126	108	500 in 2022 200 in 2023+	500	400
Number of Total Projects Allowed	8	10	5	5	30	60	100
Total MW Allowed	2,600	1,000	630	540	1,500	1,500	2,000

Several factors were taken into consideration for constraints on new wind:

1. Timing: the first year new wind was available was January 1, 2022. The PowerSimm model operates on a calendar year basis, which means that new build decisions will occur on January 1st. Because of the expected contracting and construction lead time required for new wind, it is expected that the in-service date for new wind in 2021 would be at the end of the calendar year. Therefore, the first year new wind is available is 2022, but the cost of the new wind is based on 2021 in-service with 80% PTC.
2. Number of projects per year: IPL allowed up to 500 MW of wind to be built in 2022 and 200 MW per year for every year after that. Wind pricing with 80% PTC eligibility provides a significant cost advantage, and because IPL is in net long position, the model was limited in capacity additions for 2022. Beyond 2022, IPL limited annual wind build to 200 MW due to concerns over the availability of wind projects after the phaseout of the PTC. As shown in Figure 7.20, the amount of wind in Indiana in the MISO Generation Interconnection Queue decreases significantly after 2020 as many developers are shifting focus to meeting solar ITC safe harbor deadlines.

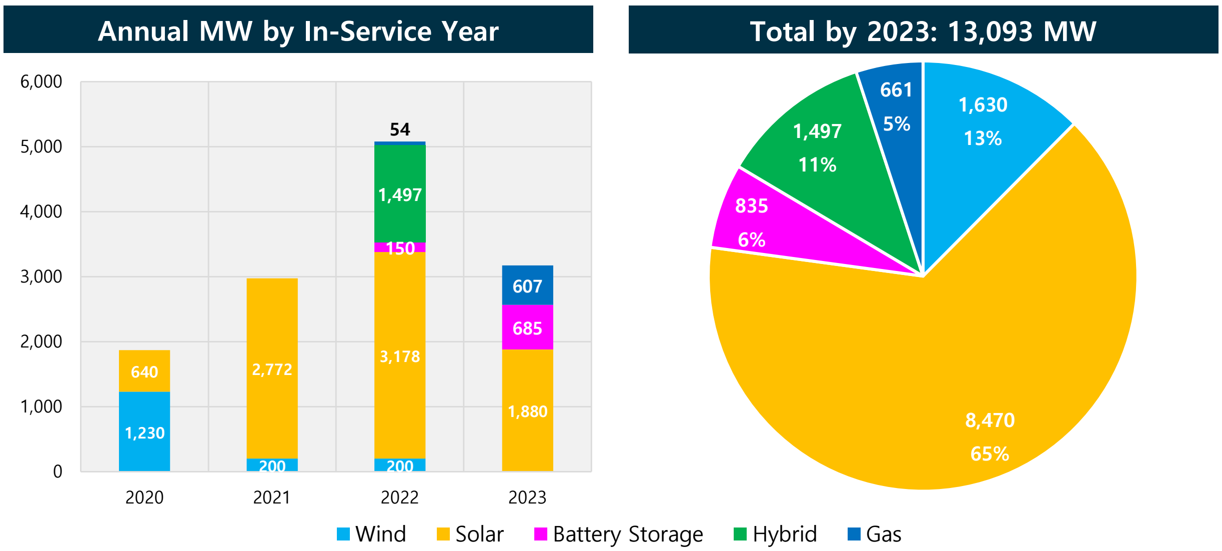
NREL's *2018 Standard Scenarios Report*[27] confirms the overall trend in lower expectations for wind development after the PTC expires. In their analysis of national wind installations over time, NREL concluded:

> Following the expiration of the PTC, most scenarios show little to no growth in wind capacity for several years (see Figure 29). Some scenarios show wind capacity stagnant or even declining for many years. Drivers of this slow wind growth are as expected, with low natural gas prices, high wind costs, and low demand, which all push demand for new wind downward.

IPL will continue to closely monitor market developments, MISO queue positions (Figure 7.20), and other factors through time and will adjust wind availability in the model accordingly.

[27] https://www.nrel.gov/analysis/standard-scenarios.html

Figure 7.20 | MISO Generation Interconnection Queue[28] for Indiana Projects



Source Data: MISO Generation Inteconnection Queue as of 11/10/2019

7.3.6 Financial Assumptions

Figure 7.21 and Figure 7.22 contain assumptions on IPL's capital structure, the discount rate used in the model, and other relevant financial assumptions used in the revenue requirement financial model.

Figure 7.21 | Capital Structure and Discount Rate in 2019 IRP

	Cap. Mix	Cost of Capital	WACC	Discount Rate
Debt	54.73%	4.98%	2.726%	2.048%
Preferred	1.82%	5.37%	0.098%	0.098%
Equity	43.45%	9.99%	4.341%	4.341%
Total	100.00%		7.164%	6.486%
			Actual	Effective
		State Tax	4.90%	4.90%
		Federal Tax	21.00%	19.97%
		Effective Tax Rate		24.87%

[28] https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/

Figure 7.22 | Financial Model Assumptions

	2020
Property Tax Rate (%)	1.30%
Working Capital Factor ($M/MW)	0.0023
Gross Revenue Conversion Factor (Bad Debt and Expense)	1.02
Gross Revenue Conversion Factor (Capital)	1.23
Inflation	2.00%

7.4 Sensitivity Analysis

A sensitivity measures how a candidate resource portfolio performs across a range of possibilities for a specific risk or variable. IPL used both deterministic and probabilistic sensitivities to examine risks of the portfolios.

IPL identified four key drivers of uncertainty impacting candidate resource portfolios:

1. Future projections of wind, solar, and storage costs
2. MISO capacity prices
3. Modeled wind capacity factors
4. Wind LMP Basis and Captured Revenue

These sensitivities did not require additional production cost model runs because the sensitivity analysis is conducted in the financial revenue requirement model.

7.4.1 Capital Cost Sensitivities

IPL conducted a thorough research process to develop a base set of capital cost assumptions for alternative resources. This included a wide range of forecasts benchmarked to recent pricing seen in Indiana. However, there is still uncertainty for capital cost projections for wind, solar, and storage, especially past the 5-year window. NREL and other vendors use a variety of methods to estimate learning curves and cost trajectories for those technologies, but as recent history has shown, long term cost estimates for these technologies have been off the mark.

Therefore, IPL developed a set of sensitives around the capital costs and applied them to all five portfolios for the Reference Case and Carbon Tax Case. Cost adjustment curves were applied to capital costs for wind, solar, and storage. Adjustments were made to all three technologies together – this means that for a specific sensitivity, capital costs for wind, solar, and storage were moved by the same percentage and applied to the new build in each candidate resource portfolio.

For this exercise, IPL assumed that uncertainty increases through time. For example, we have more certainty about the cost of solar in Year 3 than we do in Year 15, so the range of costs should be greater in the later part of the study. Figure 7.23, Figure 7.24 and Figure 7.25 illustrate the range of capital costs for wind, solar and storage analyzed through the study period for this sensitivity analysis.

Figure 7.23 | Wind Capital Cost Sensitivity Range (2018$/kW; includes PTC)

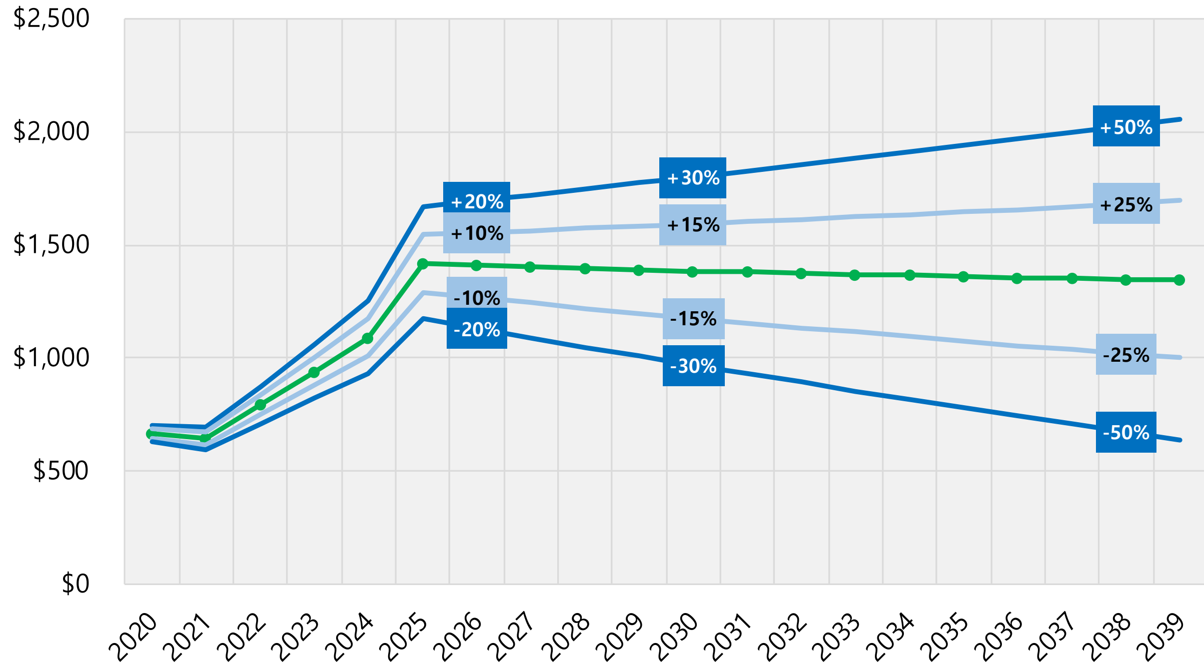


Figure 7.24 | Solar Capital Cost Sensitivity Range (2018$/kW$_{AC}$; includes ITC)

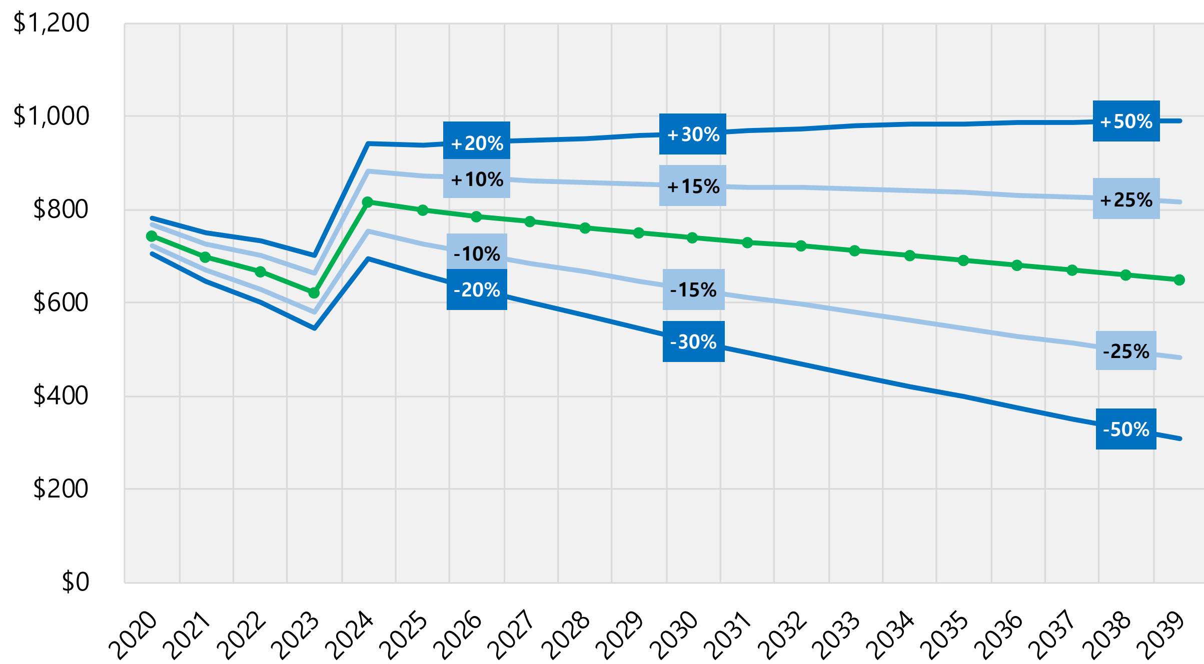
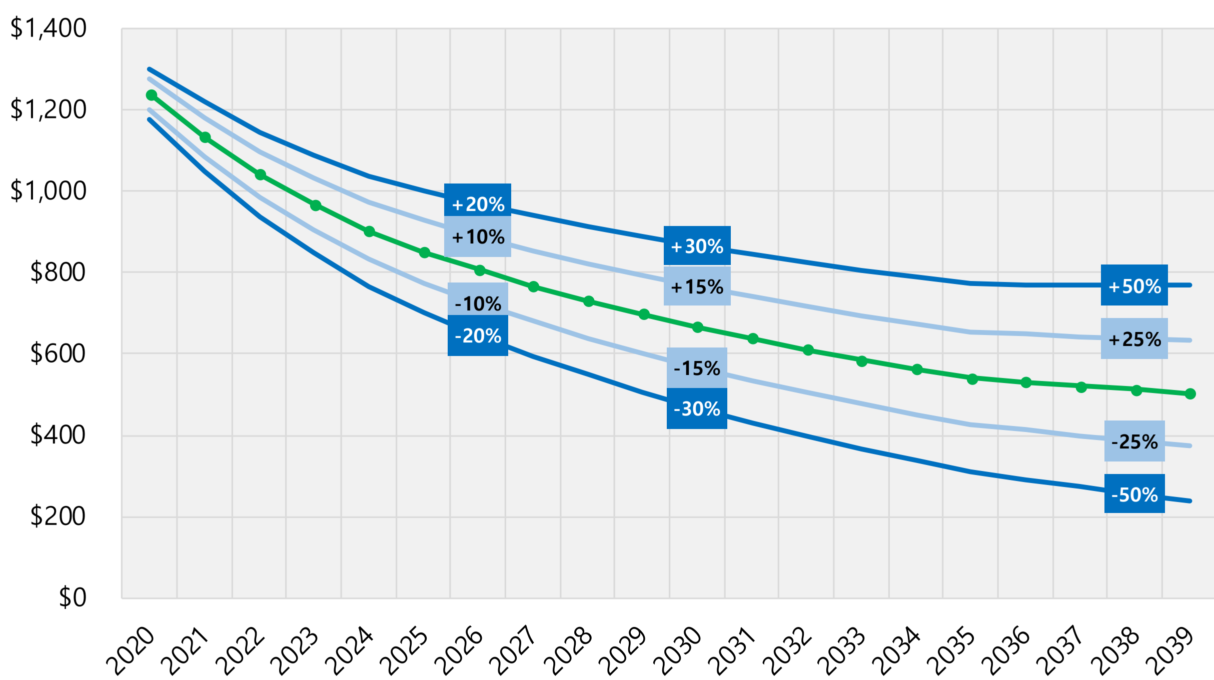


Figure 7.25 | Storage Capital Cost Sensitivity Range (2018$/kW)



7.4.2 Capacity Price Sensitivity

Capacity prices were simulated using a triangular distribution in PowerSimm for production cost runs as described in Section 7.3.3. IPL also conducted a deterministic sensitivity analysis to evaluate the impact of capacity prices on portfolio cost for the Reference Case and the Carbon Tax Case (Scenario A). The capacity position (MW) was fixed for each candidate resource portfolio and was the same for both scenarios, and annual capacity prices were applied to the capacity length to generate a set of PVRRs for comparison.

7.4.3 Wind Capacity Factor Sensitivity

As described in Section 5.3.1, IPL utilized the NREL Wind Toolkit to develop wind production profiles for generic new wind projects. IPL selected a midpoint 42% net capacity factor for simulated wind sites in Benton County, IN. Wind capacity factors are a function of the strength of the wind resource in a region, turbine size and technology, hub height, and other factors such as localized congestion and curtailment patterns. Additionally, while newer wind projects in the Midwest have achieved capacity factors greater than 40%, most projects installed in the Great Lakes region in the past five years have seen net capacity factors closer to 35%. The U.S. Department of Energy 2018 Wind Technologies Market Report[29] (Figure 7.26) shows 2018 calendar year capacity factors by U.S. region. The Great Lakes region, which includes Indiana, shows capacity factors in the range of about 20% to 45% with a weighted average of just over 35%.

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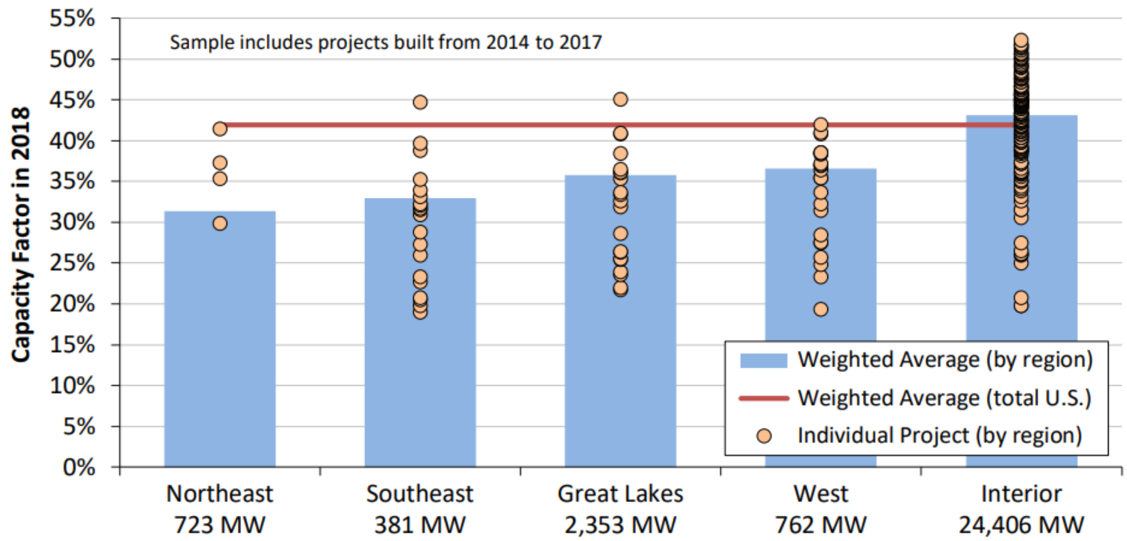
[29] U.S. Department of Energy, *2018 Wind Technologies Market Report.* Retrieved from: https://emp.lbl.gov/sites/default/files/wtmr_final_for_posting_8-9-19.pdf

Figure 7.26 | Calendar year 2018 capacity factors by region: 2014–2017 projects only



Source: Berkeley Lab

Because of the uncertainty of what a potential new Indiana wind farm could produce, IPL conducted a sensitivity on the MWh produced by the modeled generic wind project for each portfolio. Figure 7.27 shows an example of how the sensitivity was set up. The "captured revenue", which is the generation-weighted revenue in $/MWh, was fixed, but the annual MWh of wind production was varied to estimate the impact of a different capacity factor than what we modeled in the base wind asset. The result is a different revenue value received by wind in the model. It is possible that re-simulating the wind units with different capacity factors at the same location could yield a different captured revenue, but the impact would likely be insignificant and would not change the insight this sensitivity provides.

Results from this sensitivity analysis can be found in Section 8.4.3.

Figure 7.27 | Wind Capacity Factor Sensitivity: Example Setup

Annual Capacity Factor	Percent Difference from Base	Annual MWh from 50 MW Project	Portfolio 3 2022 Build: 250 MW	2022 Captured Revenue ($/MWh)	2022 Portfolio 3 Wind Revenue ($MM)
46%	9%	201,480	1,007,400	$23.29	$23.46
44%	4%	192,720	963,600	$23.29	$22.44
[Base] 42.3%	-	185,447	927,235	$23.29	$21.60
40%	-6%	175,200	876,000	$23.29	$20.40
38%	-10%	166,440	832,200	$23.29	$19.38
36%	-15%	157,680	788,400	$23.29	$18.36
34%	-20%	148,920	744,600	$23.29	$17.34
32%	-24%	140,160	700,800	$23.29	$16.32
30%	-29%	131,400	657,000	$23.29	$15.30

7.4.4 Wind LMP Basis Sensitivity

IPL assumed the LMP basis from Indiana Hub to a generic new wind farm was approximately a 20% discount to the hub. As mentioned in Section 7.3, estimating future congestion is difficult because of the myriad of factors that could impact an individual location's LMP. A sensitivity analysis on the captured revenue of wind was included to estimate the impact of an improved LMP basis for new wind build across the portfolios. In this sensitivity analysis, wind production in MWh was fixed, and the captured revenue rate ($/MWh) was changed in increments of 5% to remove the basis assumption for new wind assets in the model.

Figure 7.28 and Figure 7.29 contain the base-modeled wind-captured revenue, which includes the LMP basis discount to Indiana Hub, as well as the sensitivity range and the LCOE by year. Results from this sensitivity analysis can be found in Section 8.4.4.

Figure 7.28 | Reference Case Wind Basis/Captured Revenue Sensitivity

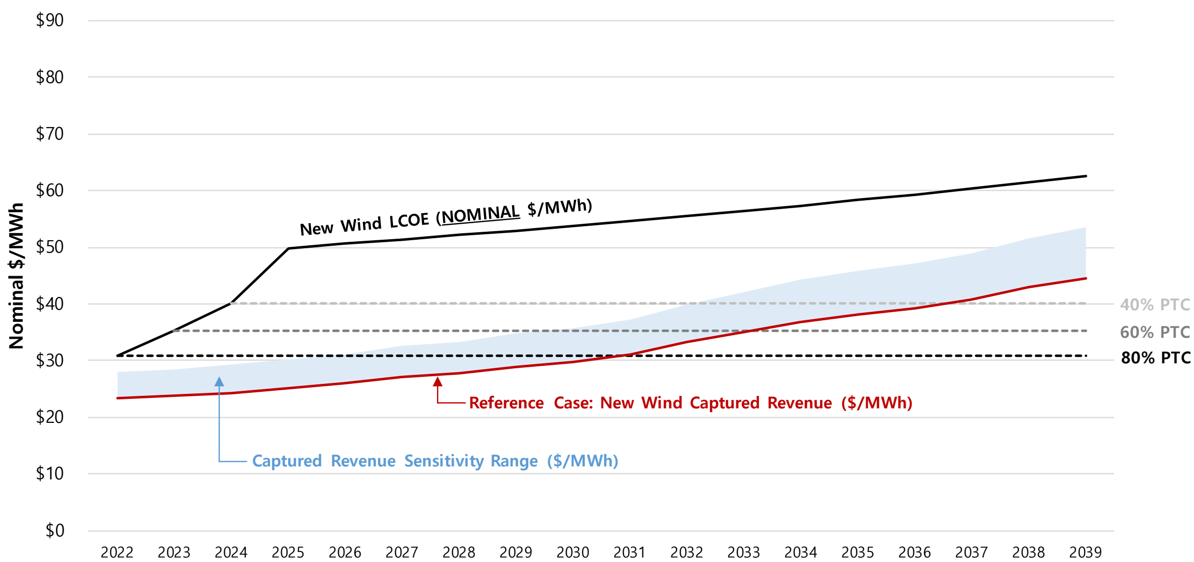
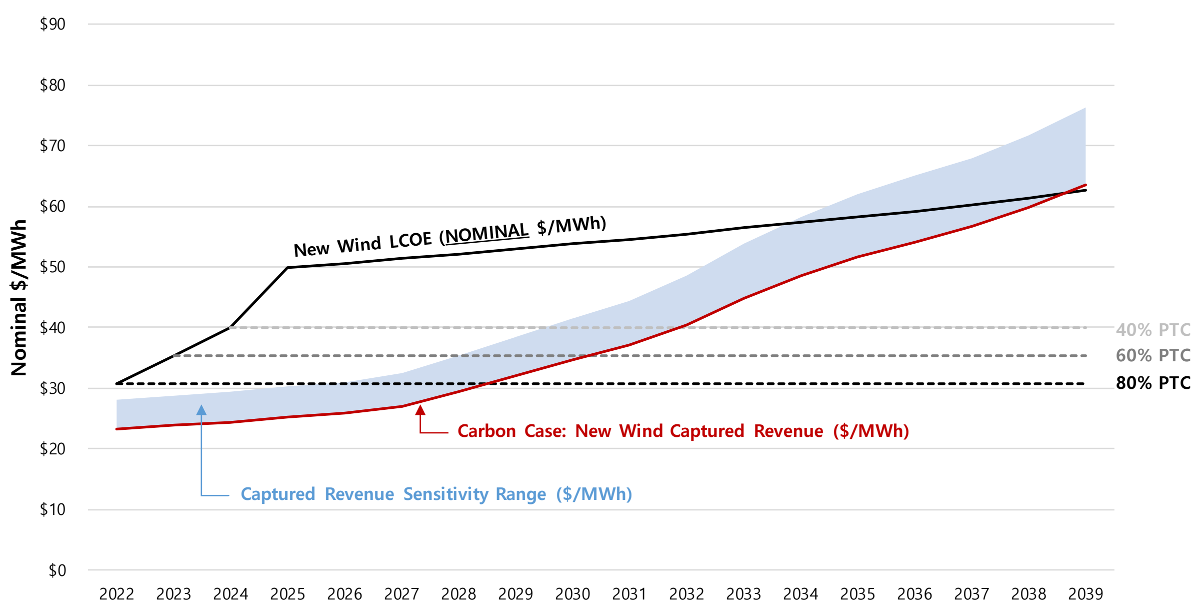


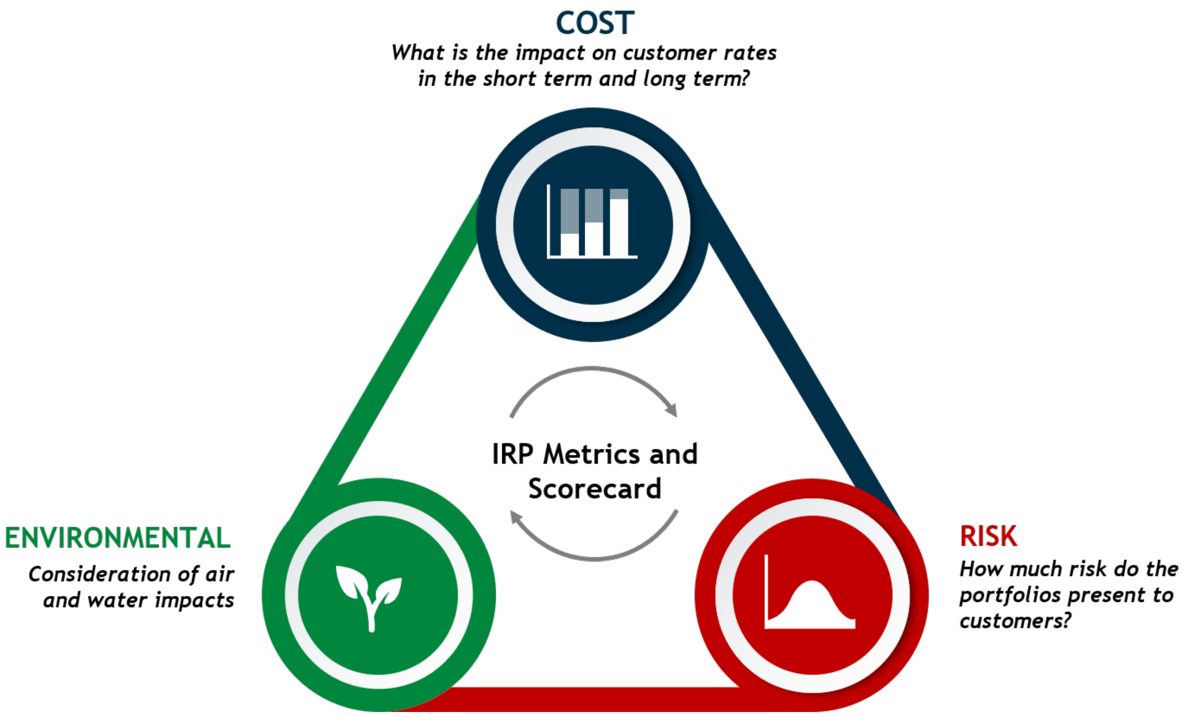
Figure 7.29 | Carbon Tax Case Wind Basis/Captured Revenue Sensitivity



7.5 Portfolio Metrics

As shown in Figure 7.30, IPL identified three primary categories of metrics for this IRP: cost, risk, and environmental. For all metrics, stochastic modeling results were used for each portfolio and scenario.

Figure 7.30 | 2019 IRP Metric Categories



7.5.1 Cost

IPL identified three primary cost metrics:

1. 20-year Present Value Revenue Requirement (PVRR)
2. Annual revenue requirement
3. Levelized $/kWh rate

PVRR is the standard portfolio metric that compares the present value cost to customers. PVRR is evaluating the incremental impact on the cost to generate and does not include transmission and distribution revenue requirement. IPL assumed that cost recovery for all approved and in-service generation does not change across portfolios or scenarios. Any change to existing depreciation schedules would be considered in a future regulatory filing, and IPL's primary objective in this IRP was to focus on the economic value of existing resources versus alternatives.

Figure 7.31 contains a table with the main components of PVRR. As described at the beginning of this section, IPL used PowerSimm for capacity expansion (PowerSimm Module #1) and hourly production cost runs (PowerSimm Module #2) and loaded that output into a financial model to calculate the revenue requirement.

Figure 7.31 | Building Blocks for Revenue Requirement

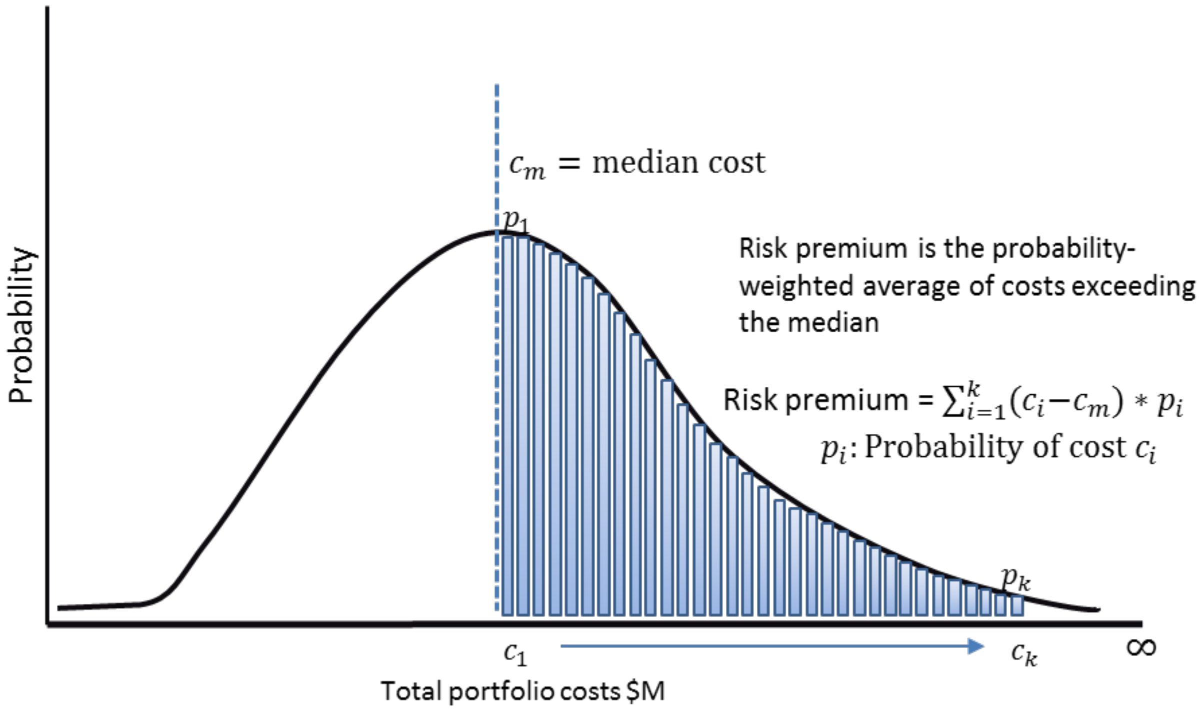
VARIABLE	DATA SOURCE	DESCRIPTION
OPERATING EXPENSES		
Energy Purchases	PowerSimm	IPL Load cost in MISO market (MW * LMP each hour)
Fuel	PowerSimm	Coal, natural gas, oil, and battery charging cost
Variable O&M	PowerSimm	Variable O&M for each technology - dependent on run time in each scenario
Fixed O&M	PowerSimm	Fixed O&M - constant across iterations and scenarios for specific portfolio
Emissions	PowerSimm	NOX, SO2, and CO2 cost - specific for each scenario
RECOVERY OF AND RETURN ON NEW CAPITAL		
Book Depreciation	Financial Model	Recovery of new capital spent; tied to capacity expansion results
Return on Rate Base	Financial Model	Rate Base * Rate of Return, grossed up for taxes
Property Taxes	Financial Model	Incremental property taxes for new capital
MARKET REVENUES		
MISO Energy Revenue	PowerSimm	MW * basis adjusted-LMP each hour for each resource, varies by scenario
Net Capacity Revenue	PowerSimm	Annual capacity length * capacity price
CALCULATION: REVENUE REQUIREMENT		
Expenses + Recovery of New Capital - Market Revenues = Revenue Requirement	PowerSimm/ Financial Model	Incremental revenue requirement for portfolio PVRR = Net present value of annual revenue requirement discounted @ IPL cost of capital

7.5.2 Risk

Not only does PowerSimm aid in the selection of the optimal energy portfolio over a wide range of future conditions, PowerSimm also identifies the risk associated with each energy portfolio option, quantifying this as the "risk premium." The risk premium is defined as the probability-weighted average of costs above the median. This concept is illustrated below in Figure 7.32.

Since different energy portfolios have different simulated cost distributions, the risk premium will be larger for wider cost distributions, or riskier portfolios, and smaller for narrower cost distributions, or less risky portfolios. After calculating the risk premium, IPL added the risk premium variable to the expected value, creating a risk-adjusted PVRR, in order to put all portfolios on the same playing field.

Figure 7.32 | Risk Premium



Risk vs Uncertainty

There are many definitions used for risk and uncertainty, but the following description from Dr. Jonathan Mun from *Modeling Risk* provides a concise summary that is relevant to how IPL is considering risk in this IRP:

> The concepts of risk and uncertainty are related but different. Uncertainty involves variables that are unknown and changing, but its uncertainty will become known and resolved through the passage of time, events, and action. Risk is something one bears and is the outcome of uncertainty. Sometimes, risk may remain constant while uncertainty increases over time.[30]

In the context of the IPL modeling framework in the IRP, uncertainty in future natural gas prices, power prices, coal prices, weather, and load are simulated in a stochastic framework across scenarios with deterministic drivers. These variables are "unknown and changing", but we will know what the actual values are as time progresses. By simulating a range of uncertainty going forward, IPL can quantify the actual impact across many possible futures, not just a base case or future of our liking. Risk in the IRP is defined as the actual cost to customers in the face of uncertainty in these key variables. IPL has chosen the risk premium metric as the way to compare all portfolios on an equal footing that incorporates risk into the decision-making process.

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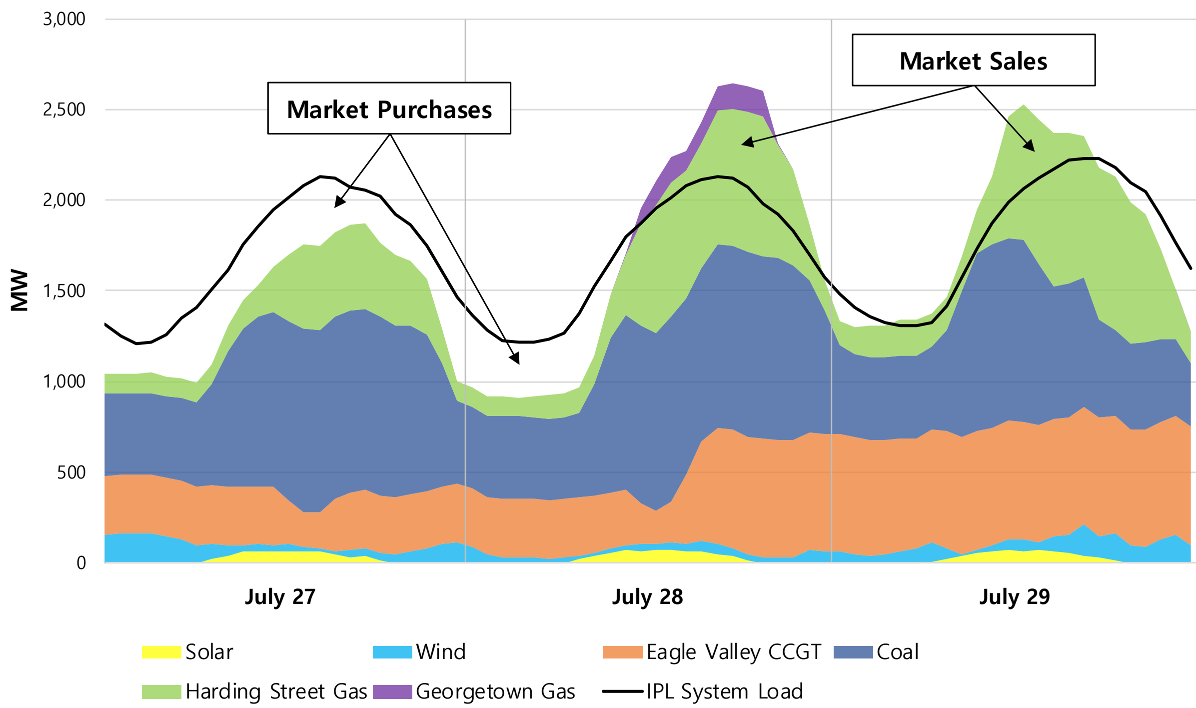
[30] Mun, J. (2006). Modeling Risk: Applying Monte Carlo Simulation, Real Options Analysis, Forecasting, and Optimization Techniques. Germany: Wiley.

The second risk metric IPL considered was a market interaction variable. This metric is based on annual market purchases and sales for each portfolio across the different scenarios. Due to hourly fluctuations in load, wholesale market prices, and unit availability, IPL can be net long or short energy throughout the year, which as a MISO market participant is characterized as market purchases and market sales. Figure 7.33 provides an example from three days in July 2019 using IPL load and generation. Across these three days, IPL was both long and short in hours as load moved, and units were committed and dispatched.

Figure 7.33 | Market Purchases and Sales Fluctuate Hourly



IPL included market interaction as a risk metric because heavy reliance on the market could introduce market price and volume risk going forward if IPL does not have a balanced portfolio. Overreliance on market purchases to serve load or overreliance on market energy sales to create value equally present risk to customers.

7.5.3 Environmental

IPL included the following environmental metrics in the 2019 IRP:

Air Emissions

- Annual CO_2 Emissions
- Annual CO_2 Intensity (tons/MWh)
- Annual SO_2 Emissions
- Annual NOx Emissions

For all air emissions, forecasted data is based on the economic dispatch of existing and new thermal units in PowerSimm across the scenarios. All metrics are based on the stochastic mean air emission output data for each portfolio and scenario.

Non-Air Emissions (Water):

IPL estimated water intake and discharge at Petersburg for the portfolios. Precise forecasts for water usage at the plant is difficult because there is not a consistent rate that can be tied to unit MWh production. For the estimate, the IPL environmental team developed a high-level estimate for the change in water usage at Petersburg for the retirement dates established in Portfolios 1-5.

Section 8: Results

170 IAC 4-7-4(24) 170 IAC 4-7-8(c)(4) 170 IAC 4-7-8(c)(8)

8.1 Executive Summary

170 IAC 4-7-4(8)

The modeling framework in the 2019 IRP produced a set of candidate portfolios optimized stochastically over a wide range of simulated futures. Each candidate portfolio was run through stochastic production cost modeling runs for each scenario, further expanding the range of uncertainty considered. This methodology allowed IPL to see how the portfolios performed in multiple scenarios, which provides insight into the risk, benefits, and overall robustness of portfolios across time and across a range of market conditions.

To ensure that the optimal level of DSM is targeted, IPL directly tested increasing DSM decrements or bundles included in the list of candidate portfolios. This was done until the PVRR increased as an incremental decrement was added. The result was fifteen (15) distinct candidate resource portfolios optimized with increasing levels of DSM. Each portfolio was locked and then run through each scenario stochastically, yielding seventy-five (75) production cost model results simulated across a range of probabilistic futures. Figure 8.1 contains a summary of the modeling structure and the naming convention that will be used throughout this section.

The technical appendix includes confidential information, most of which is in electronic format, and is available as part of the Confidential IRP.

Figure 8.1 | Portfolio Naming Convention

Portfolio	Description	DSM Decrements 1-3	DSM Decrements 1-4	DSM Decrements 1-5
Portfolio 1	No Early Retirements	1a	1b	1c
Portfolio 2	Pete Unit 1 Retire 2021 Pete Units 2-4 Operational	2a	2b	2c
Portfolio 3	Pete 1 Retire 2021; Pete 2 Retire 2023 Pete Units 3-4 Operational	3a	3b	3c
Portfolio 4	Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete Unit 4 Operational	4a	4b	4c
Portfolio 5	Pete 1 Retire 2021; Pete 2 Retire 2023; Pete 3 Retire 2026; Pete 4 Retire 2030	5a	5b	5c

8.2 Capacity Expansion Results

8.2.1 Candidate Resource Portfolios

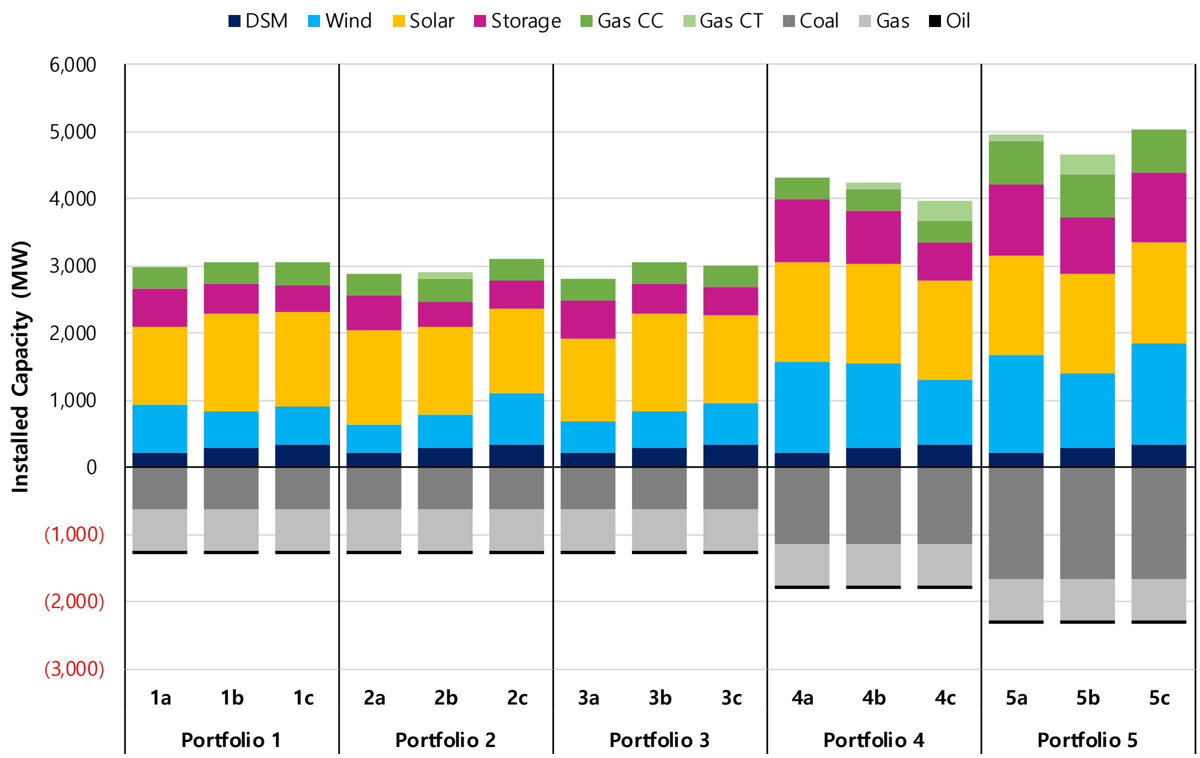
170 IAC 4-7-4(8)

Several portfolio changes are consistent across all portfolios:

- Harding Street Retirements:
  - Harding Street Oil 1-2, 40 MW, 2024
  - Harding Street Gas ST5: 100 MW, 2030
  - Harding Street Gas ST6: 98 MW, 2030
  - Harding Street Gas ST7: 420 MW, 2034
- A 1x1, 325 MW (ICAP) combined cycle was added to all portfolios in 2034 to provide firm, dispatchable capacity on the IPL 138 kV transmission system after the Harding Street steam units retire. IPL has not performed a detailed engineering or reliability study to determine if a combined cycle is the required solution. This combined cycle addition is a placeholder to represent the firm capacity needed for the IPL distribution system, a need that is currently fulfilled by a combination of natural gas units (Eagle Valley, Harding Street, Georgetown). The cost and dispatch were consistent across all portfolios, so there is no difference in PVRR attributed to the addition of this resource. The actual firm capacity need and solution will likely change through time and could be a different technology.
- Load contribution to peak and energy from electric vehicles is the same across all portfolios.
- Distributed solar was modeled as a fixed supply-side resource and was the same across all portfolios and scenarios.

Figure 8.2 contains a summary of the installed capacity changes through 2039 for all 15 candidate resource portfolios.

Figure 8.2 | Cumulative Installed Capacity Changes through 2039 (ICAP MW)



Portfolio 1 Capacity Expansion Results

Portfolio 1 is based on age-based retirement dates for all Petersburg units. No resource additions are required in this portfolio until 2033. DSM decrements were set up starting in 2021 and had to be "in-service" through the end of the study period, so additional DSM capacity was the only resource that was added before 2033 in Portfolio 1. Any incremental capacity length created from new DSM led to capacity sales at the MISO market price in the model.

Retirements in all Portfolio 1 runs were as follows:

- Petersburg Unit 1: 220 MW, 2033
- Petersburg Unit 2: 410 MW, 2035
- Harding Street Gas ST5: 100 MW, 2030
- Harding Street Gas ST6: 98 MW, 2030
- Harding Street Gas ST7: 420 MW, 2034

Figure 8.3 contains annual installed capacity additions (ICAP MW) for Portfolio 1a, 1b, and 1c and Figure 8.4 shows cumulative capacity changes (additions and retirements) through the end of the study period (2039).

Figure 8.3 | Portfolio 1 Installed Capacity Additions (MW)

Portfolio 1a: Includes Decrements 1-3

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	18	33	49	64	80	97	114	128	143	157	171	183	194	205	215	216	219	220	223
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	250	250	700
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	425	475	875	950	1,025	1,175	1,175
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	100	200	500	520	520	560	560
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

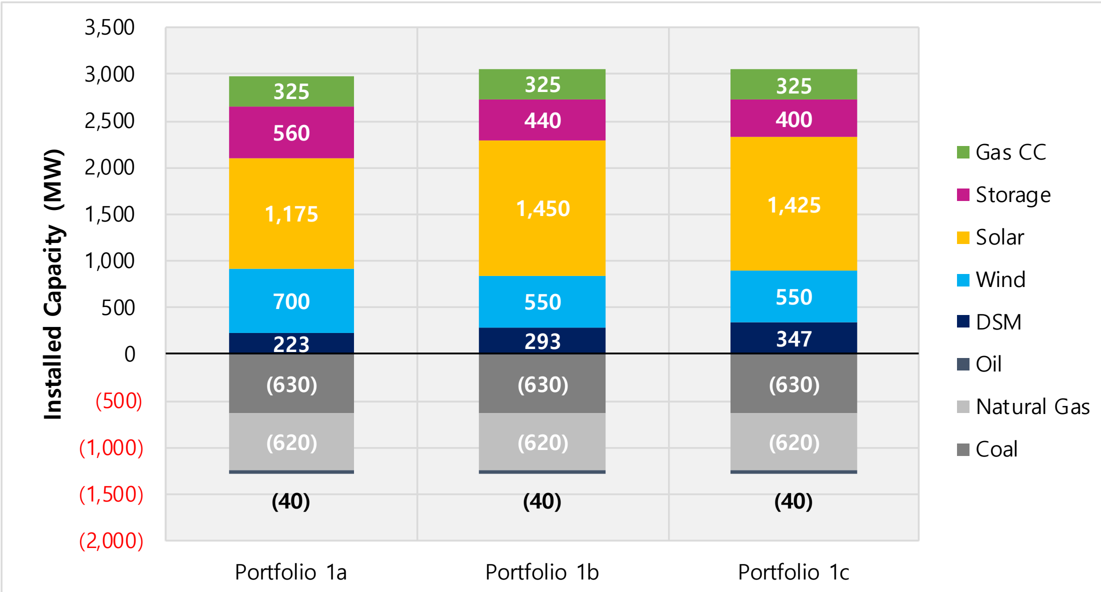
Portfolio 1b: Includes Decrements 1-4

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	150	150	550
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	500	900	1,375	1,375	1,450	1,450	1,450
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	40	40	320	360	360	440	440
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 1c: Includes Decrements 1-5

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	250	400	550
New Solar	0	0	0	0	0	0	0	0	0	0	0	0	0	500	825	1,250	1,325	1,325	1,425	1,425
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	300	320	340	380	400
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 8.4 | Portfolio 1 Cumulative Installed Capacity Changes through 2039 (MW)



Portfolio 2 Capacity Expansion Results

Portfolio 2 included early retirement of Petersburg Unit 1 in 2021. Even with the retirement of Pete 1, no capacity additions are needed until 2031 in this portfolio and DSM was the only resource added before 2031.

Retirements in all Portfolio 2 runs were as follows:

- Petersburg Unit 1: 220 MW, 2021
- Petersburg Unit 2: 410 MW, 2035
- Harding Street Gas ST5: 100 MW, 2030
- Harding Street Gas ST6: 98 MW, 2030
- Harding Street Gas ST7: 420 MW, 2034

Figure 8.5 contains annual installed capacity additions (ICAP MW) for Portfolio 2a, 2b, and 2c and Figure 8.6 shows cumulative capacity changes (additions and retirements) through the end of the study period (2039).

Figure 8.5 | Portfolio 2 Installed Capacity Additions (MW)

Portfolio 2a: Includes Decrements 1-3

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	18	33	49	64	80	97	114	128	143	157	171	183	194	205	215	216	219	220	223
New Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	350	400
New Solar	0	0	0	0	0	0	0	0	0	0	0	125	125	175	500	900	1,050	1,150	1,375	1,425
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	160	180	180	200	500	500	500	500	520
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

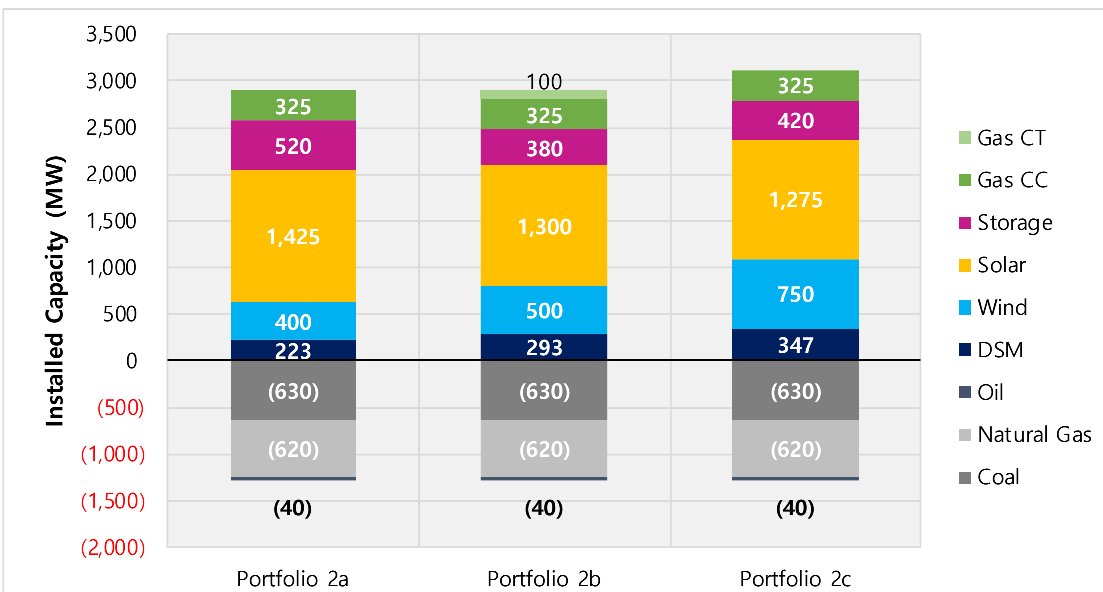
Portfolio 2b: Includes Decrements 1-4

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
New Wind	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100	100	450	500	500
New Solar	0	0	0	0	0	0	0	0	0	0	0	350	350	400	800	900	900	900	1,175	1,300
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	40	60	60	60	340	380	380	380	380
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	100	100	100	100

Portfolio 2c: Includes Decrements 1-5

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
New DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
New Wind	0	0	0	0	0	0	0	0	0	0	0	50	50	100	100	200	200	500	600	750
New Solar	0	0	0	0	0	0	0	0	0	0	0	400	450	475	800	1,150	1,150	1,175	1,200	1,275
New Battery Storage	0	0	0	0	0	0	0	0	0	0	0	0	0	0	20	320	360	360	420	420
New Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
New Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 8.6 | Portfolio 2 Cumulative Installed Capacity Changes through 2039 (ICAP MW)



Portfolio 3 Capacity Expansion Results

Portfolio 3 included the retirement of Pete 1 in 2021 and Pete 2 in 2023. Before new capacity additions, this results in a capacity shortfall starting in 2023. Even without a capacity need until 2023, DSM was made available starting in 2021 and wind in 2022.

Retirements in all Portfolio 3 runs were as follows:

- Petersburg Unit 1: 220 MW, 2021
- Petersburg Unit 2: 410 MW, 2023
- Harding Street Gas ST5: 100 MW, 2030
- Harding Street Gas ST6: 98 MW, 2030
- Harding Street Gas ST7: 420 MW, 2034

Figure 8.7 | Portfolio 3 Installed Capacity Additions (MW)

Portfolio 3a: Includes DSM Decrements 1-3

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	18	33	49	64	80	97	114	128	143	157	171	183	194	205	215	216	219	220	223
Wind	0	0	250	250	250	250	250	250	250	250	250	250	250	250	250	350	350	400	400	450
Solar	0	0	0	375	425	475	550	575	650	700	700	700	725	725	725	725	725	825	1,125	1,250
Battery Storage	0	0	0	40	80	80	80	100	100	100	120	340	360	380	500	520	560	560	560	560
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

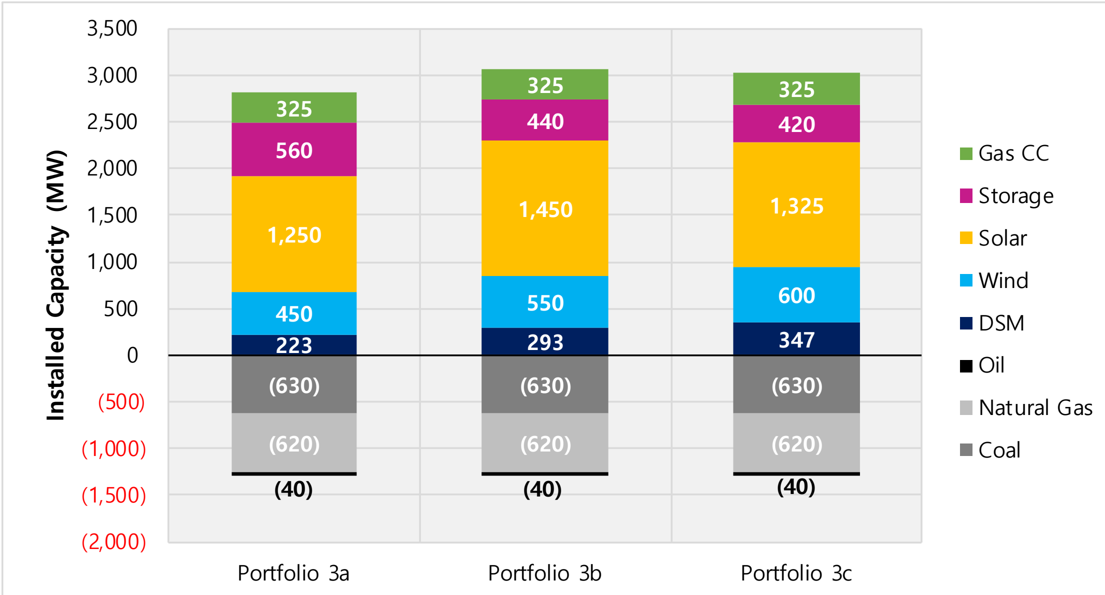
Portfolio 3b: Includes DSM Decrements 1-4

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
Wind	0	0	100	100	100	100	100	100	150	150	150	150	150	250	250	250	250	300	450	550
Solar	0	0	0	450	600	650	725	750	750	800	850	925	1,000	1,050	1,050	1,075	1,075	1,175	1,350	1,450
Battery Storage	0	0	0	0	0	0	0	20	40	40	40	240	240	240	360	380	420	420	440	440
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Portfolio 3c: Includes DSM Decrements 1-5

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
Wind	0	0	150	150	150	150	150	150	150	200	250	250	300	300	300	350	350	400	450	600
Solar	0	0	0	400	525	575	575	575	625	650	675	725	725	775	825	825	875	975	1,250	1,325
Battery Storage	0	0	0	20	20	20	40	60	60	60	60	260	280	280	380	400	420	420	420	420
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 8.8 | Portfolio 3 Cumulative Installed Capacity Changes through 2039 (MW)



Portfolio 4 Capacity Expansion Results

Portfolio 4 included the retirement of Pete 1 in 2021, Pete 2 in 2023, and Pete 3 in 2026. This results in a capacity shortfall of approximately 258 MW in 2023, 900 MW in 2026. Capacity expansion was run to allow the model to optimally fill that capacity shortfall.

Retirements in all Portfolio 4 runs were as follows:

- Petersburg Unit 1: 220 MW, 2021
- Petersburg Unit 2: 410 MW, 2023
- Petersburg Unit 3: 520 MW, 2026
- Harding Street Gas ST5: 100 MW, 2030
- Harding Street Gas ST6: 98 MW, 2030
- Harding Street Gas ST7: 420 MW, 2034

Figure 8.9 | Portfolio 4 Installed Capacity Additions (MW)

Portfolio 4a: Includes Decrements 1-3

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	18	33	49	64	80	97	114	128	143	157	171	183	194	205	215	216	219	220	223
Wind	0	0	500	500	500	500	550	600	600	600	700	800	850	900	950	950	950	1,150	1,150	1,350
Solar	0	0	0	450	600	650	1,125	1,225	1,325	1,350	1,350	1,350	1,375	1,400	1,400	1,450	1,475	1,475	1,475	1,475
Battery Storage	0	0	0	0	0	0	340	340	340	360	380	600	620	640	760	780	820	840	920	940
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

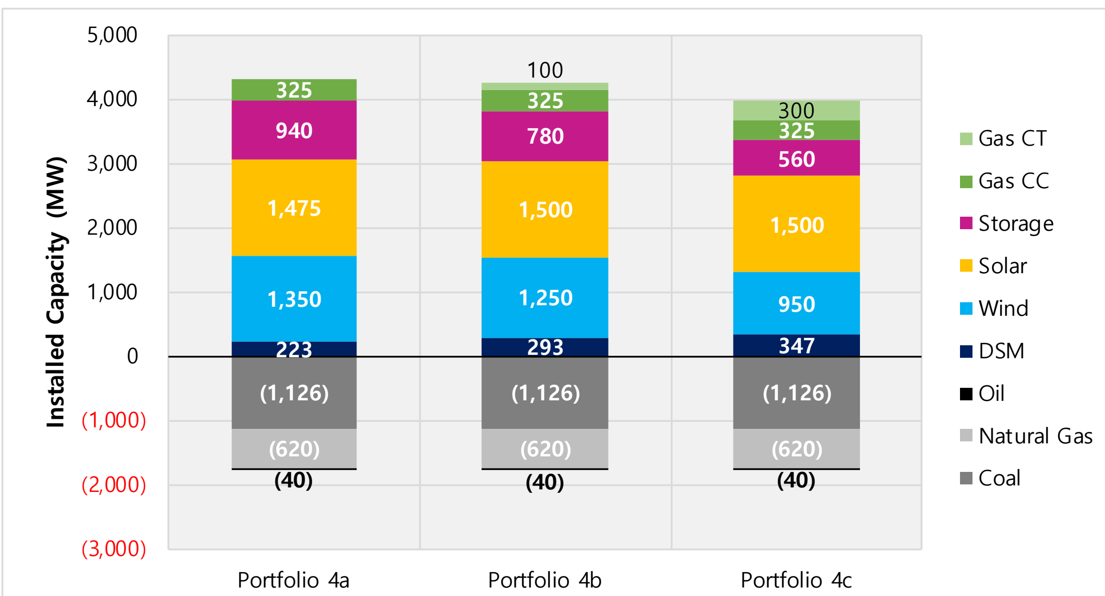
Portfolio 4b: Includes Decrements 1-4

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
Wind	0	0	400	400	400	400	400	400	550	550	600	600	700	800	800	850	950	1,100	1,250	1,250
Solar	0	0	0	425	550	600	1,100	1,200	1,250	1,325	1,325	1,350	1,350	1,350	1,350	1,375	1,425	1,425	1,450	1,500
Battery Storage	0	0	0	0	0	0	240	240	240	240	260	480	500	520	640	660	680	700	760	780
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Portfolio 4c: Includes Decrements 1-5

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
Wind	0	0	400	400	400	400	400	400	450	450	450	450	550	600	600	650	650	800	800	950
Solar	0	0	0	400	400	400	900	925	925	975	1,025	1,475	1,475	1,475	1,475	1,500	1,500	1,500	1,500	1,500
Battery Storage	0	0	0	20	80	80	200	220	240	240	240	320	340	360	380	400	440	460	540	560
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	200	200	200	200	200	200	200	200	300	300	300	300	300	300

Figure 8.10 | Portfolio 4 Cumulative Installed Capacity Changes through 2039 (MW)



Portfolio 5 Capacity Expansion Results

Portfolio 4 included the retirement of Pete 1 in 2021, Pete 2 in 2023, Pete 3 in 2026, and Pete 4 in 2030. The retirement of these units leaves IPL with a sizeable capacity shortfall with retirements:

- Capacity Shortfall before any new resources:
    - 2023: 258 MW UCAP
    - 2027: 900 MW UCAP
    - 2031: 1,700 MW UCAP

Retirements in all Portfolio 5 runs were as follows:

- Petersburg Unit 1: 220 MW, 2021
- Petersburg Unit 2: 410 MW, 2023
- Petersburg Unit 3: 520 MW, 2026
- Petersburg Unit 4: 520 MW, 2030
- Harding Street Gas ST5: 100 MW, 2030
- Harding Street Gas ST6: 98 MW, 2030
- Harding Street Gas ST7: 420 MW, 2034

Figure 8.11 | Portfolio 5 Installed Capacity Additions (MW)

Portfolio 5a: Includes Decrements 1-3

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	18	33	49	64	80	97	114	128	143	157	171	183	194	205	215	216	219	220	223
Wind	0	0	500	500	500	500	550	600	600	600	700	800	850	900	950	950	950	1,150	1,150	1,350
Solar	0	0	0	450	600	650	1,125	1,225	1,325	1,350	1,350	1,350	1,375	1,400	1,400	1,450	1,475	1,475	1,475	1,475
Battery Storage	0	0	0	0	0	0	340	340	340	360	380	600	620	640	760	780	820	840	920	940
Gas CC	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325	325	325	325	325
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

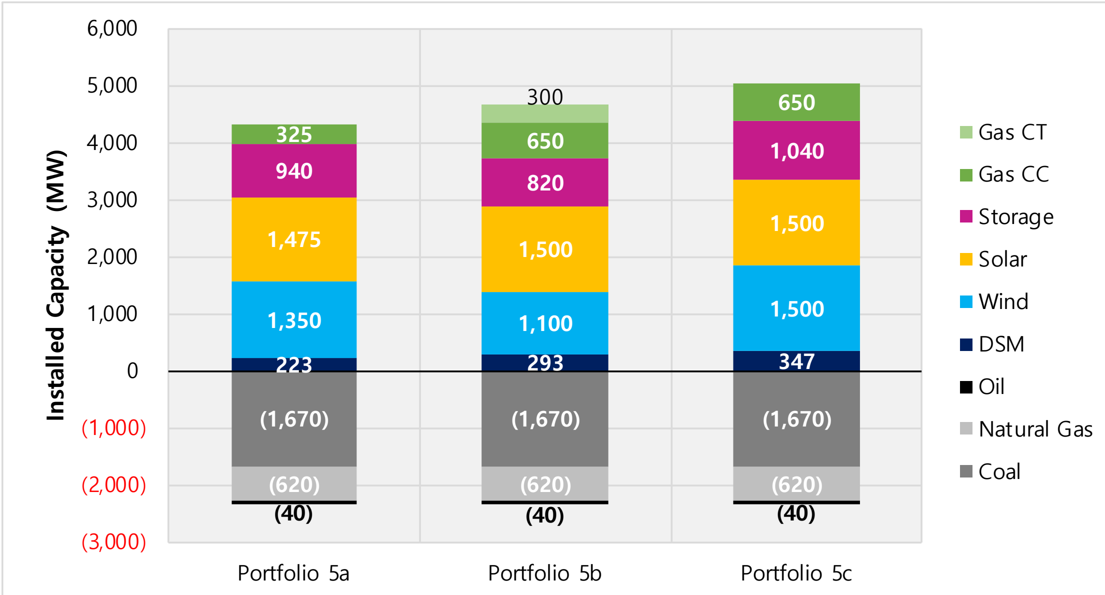
Portfolio 5b: Includes Decrements 1-4

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	23	44	63	83	103	124	143	162	181	199	215	230	244	257	271	276	282	288	293
Wind	0	0	350	350	350	350	350	350	400	450	450	450	450	550	550	600	600	800	1,000	1,100
Solar	0	0	0	425	550	600	1,100	1,200	1,275	1,275	1,325	1,350	1,375	1,375	1,450	1,475	1,475	1,475	1,475	1,500
Battery Storage	0	0	0	0	0	0	20	20	20	40	300	520	540	560	660	680	720	740	800	820
Gas CC	0	0	0	0	0	0	325	325	325	325	325	325	325	325	650	650	650	650	650	650
Gas CT	0	0	0	0	0	0	0	0	0	0	300	300	300	300	300	300	300	300	300	300

Portfolio 5c: Includes Decrements 1-5

Resource Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039
DSM	0	28	50	73	97	120	145	170	191	212	235	252	269	288	303	319	326	332	338	347
Wind	0	0	500	500	500	500	500	550	550	750	950	1,150	1,150	1,200	1,200	1,300	1,300	1,300	1,500	1,500
Solar	0	0	0	425	500	525	725	775	775	775	1,225	1,375	1,400	1,400	1,400	1,400	1,400	1,450	1,450	1,500
Battery Storage	0	0	0	0	20	20	140	140	160	160	560	720	740	760	880	900	940	960	1,020	1,040
Gas CC	0	0	0	0	0	0	325	325	325	325	325	325	325	325	650	650	650	650	650	650
Gas CT	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 8.12 | Portfolio 5 Cumulative Installed Capacity Changes through 2039 (MW)



IPL produced Annual Energy Charts (Attachment 8.1) and Load Resource Balance charts (Attachment 8.2) for all portfolios and scenarios. These show how the model selected portfolios that could meet IPL's energy requirements, as well as IPL capacity requirements to reliably serve demand throughout the study period.

Figure 8.13 contains cumulative CAPEX spending (plant entering service) for new and existing assets for each portfolio. The timing of coal unit retirements and need for replacement capacity is the largest driver of differences between portfolios. Portfolio 1 would require approximately $630 million in capital expenditures at Petersburg for environmental and maintenance capital through 2030, and most of the capital is required 2031 – 2039 with the retirement of Pete 1, Pete 2, and the Harding Street steam units. Portfolio 5 requires the largest capital expenditure, with $3-4 billion required by 2030 to replace the capacity from Petersburg Units 1-4.

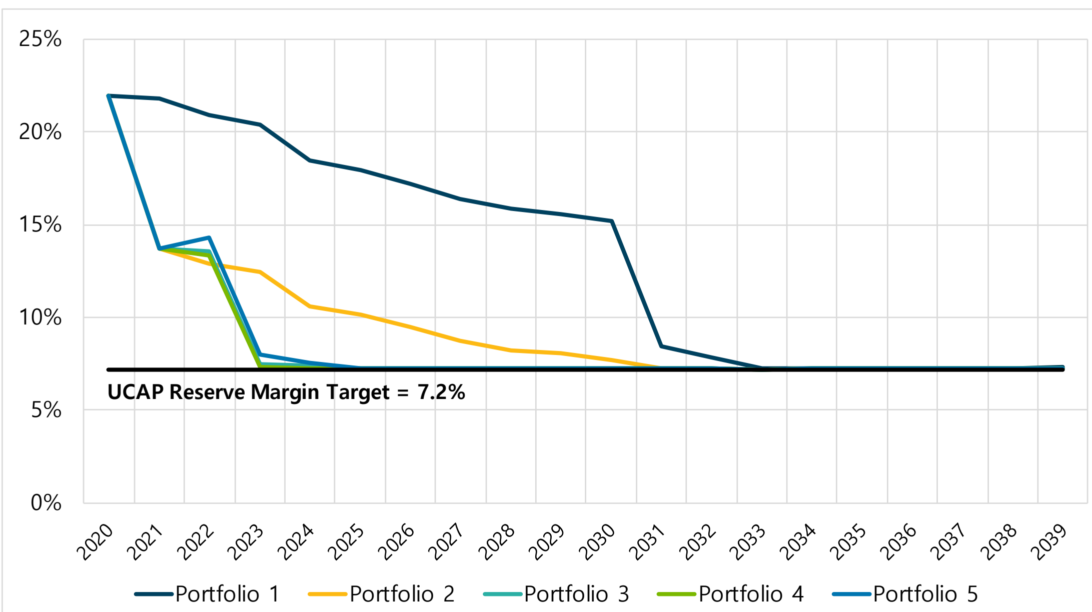
Figure 8.13 | Cumulative CAPEX Spend by Portfolio (Nominal $Billion)

		2025	2030	2035	2039
Portfolio 1	1a	$0.4	$0.6	$2.7	$4.4
	1b	$0.4	$0.6	$2.8	$4.3
	1c	$0.4	$0.6	$2.9	$4.2
Portfolio 2	2a	$0.4	$0.5	$2.4	$3.9

	2b	$0.4	$0.5	$2.6	$3.9
	2c	$0.4	$0.5	$2.9	$4.3
Portfolio 3	3a	$1.0	$1.3	$2.5	$3.3
	3b	$0.9	$1.3	$2.6	$3.7
	3c	$0.9	$1.3	$2.5	$3.7
Portfolio 4	4a	$1.2	$2.7	$4.1	$5.2
	4b	$1.1	$2.6	$4.0	$5.1
	4c	$1.0	$2.1	$3.7	$4.5
Portfolio 5	5a	$1.3	$3.6	$4.9	$5.8
	5b	$1.0	$2.9	$4.1	$5.3
	5c	$1.1	$3.5	$5.1	$5.7

Figure 8.14 shows the annual reserve margin target for each portfolio. There are small variations in reserve margins for the portfolios optimized with Decrements 1-4 and 1-5, but the changes are negligible and not shown in this figure.

Figure 8.14 | Annual Reserve Margin by Portfolio (UCAP Reserve Margin %)



8.3 Scenarios and Metrics

170 IAC 4-7-8(b)

Capacity expansion portfolios were locked and simulated stochastically through all scenarios. This allowed IPL to see how portfolios performed across many futures, not just the set of assumptions used to optimize the portfolio. Frequently stochastic modeling is used only for the "base case" or "reference case" scenario. While this analysis can be valuable, modeling each scenario stochastically effectively widens the range of uncertainty, which is particularly valuable in capturing fundamental or systemic changes to fundamental forecasts.

Figure 8.15 contains PVRR results for all seventy-five model runs. PVRRs are based on mean (average) PowerSimm model results, and portfolio builds are fixed across all scenarios. Color gradients reflect the ranking of portfolios within each specific scenario, with the lowest PVRR in white and the highest portfolio shaded the darkest color.

Figure 8.15 | Expected Value 20-Year PVRR ($MM)

	Reference Case	Scenario A: Carbon Tax Case	Scenario B: Carbon + High Gas	Scenario C: Carbon + Low Gas + Low Load	Scenario D: No Carbon + High Gas + High Load
Portfolio 1a	$7,215	$8,018	$8,427	$7,137	$7,923
Portfolio 2a	$7,132	$7,932	$8,399	$7,017	$7,900
Portfolio 3a	$7,016	$7,737	$8,211	$6,843	$7,798
Portfolio 4a	$7,295	$7,740	$8,174	$6,922	$8,070
Portfolio 5a	$7,500	$7,819	$8,329	$6,948	$8,376
Portfolio 1b	$7,176	$7,950	$8,338	$7,087	$7,864
Portfolio 2b	$7,188	$7,956	$8,398	$7,062	$7,932
Portfolio 3b	$6,976	$7,661	$8,114	$6,786	$7,739
Portfolio 4b	$7,293	$7,742	$8,191	$6,907	$8,082
Portfolio 5b	$7,400	$7,703	$8,272	$6,769	$8,259
Portfolio 1c	$7,223	$7,980	$8,355	$7,128	$7,899
Portfolio 2c	$7,191	$7,923	$8,341	$7,051	$7,912
Portfolio 3c	$7,034	$7,716	$8,165	$6,842	$7,794
Portfolio 4c	$7,269	$7,747	$8,225	$6,883	$8,086
Portfolio 5c	$7,452	$7,716	$8,202	$6,857	$8,306

8.3.1 Reference Case

170 IAC 4-7-4(25)

The Reference Case includes IPL's view of the future based on the current trajectory. This means commodity prices for power and gas reflect the base case forecasts. More importantly, the Reference Case does not include any carbon tax. Figure 8.16 shows the 20-year PVRR for each portfolio from the Reference Case.

Figure 8.16 | Reference Case 20-Year PVRR by Portfolio ($B)

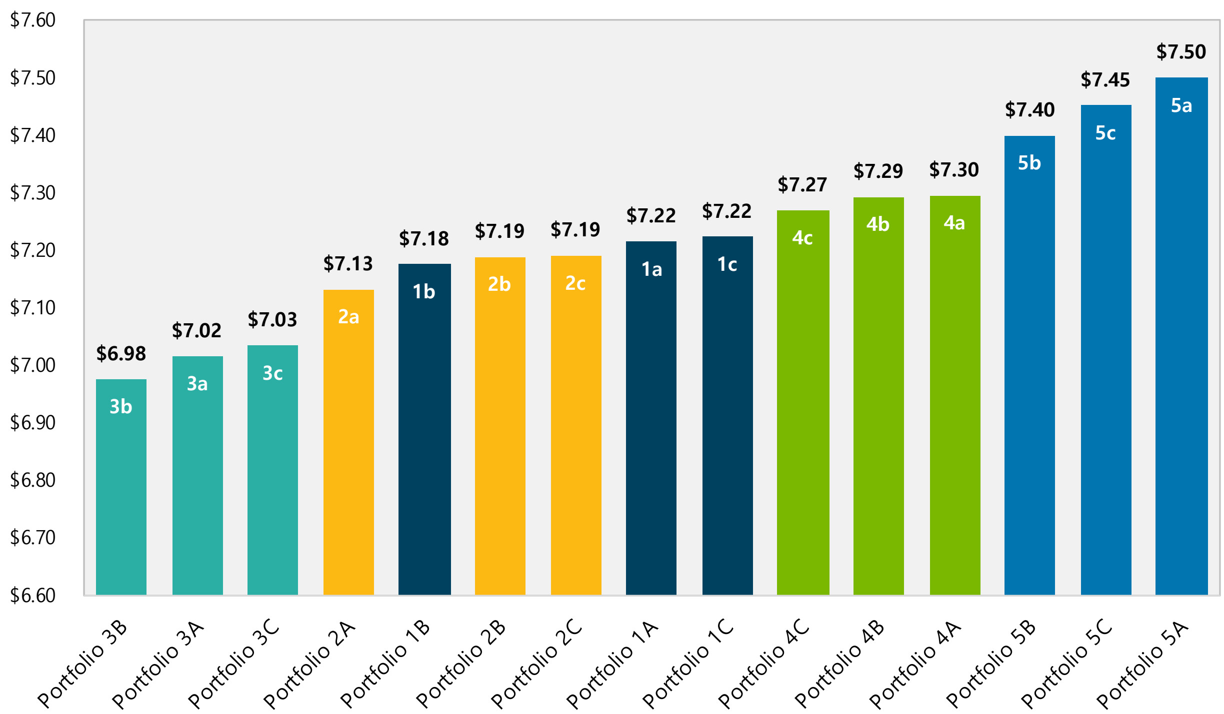
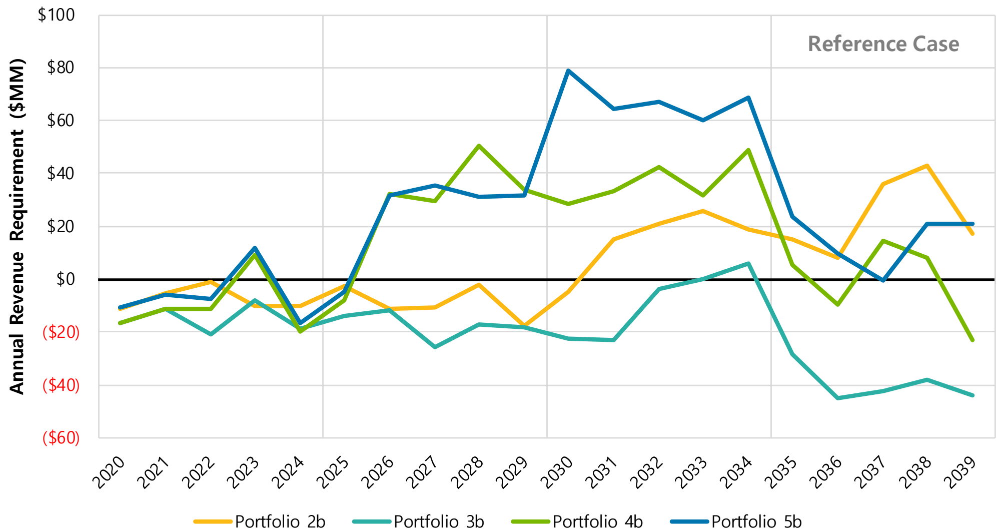


Figure 8.17 shows annual revenue requirement differences from Portfolio 1b. There are only slight differences between Portfolios a-c when looking at annual portfolio costs, so only Portfolio 2b-5b are shown. The annual revenue requirement for Portfolio 3 remains at or below Portfolio 1 for almost every year of the study, even when capacity additions are required by 2023. This is primarily because new capital spent for replacement capacity is generally offset by capex and O&M savings at Petersburg 1 and 2. Portfolios 4 and 5 require significant capital expenditures to replace all four Petersburg units, and that drives a higher revenue requirement in the 2026 – 2033 time frame.

Figure 8.17 | Annual Difference from Portfolio 1b (Nominal $MM)



8.3.2 Scenario A: Carbon Tax

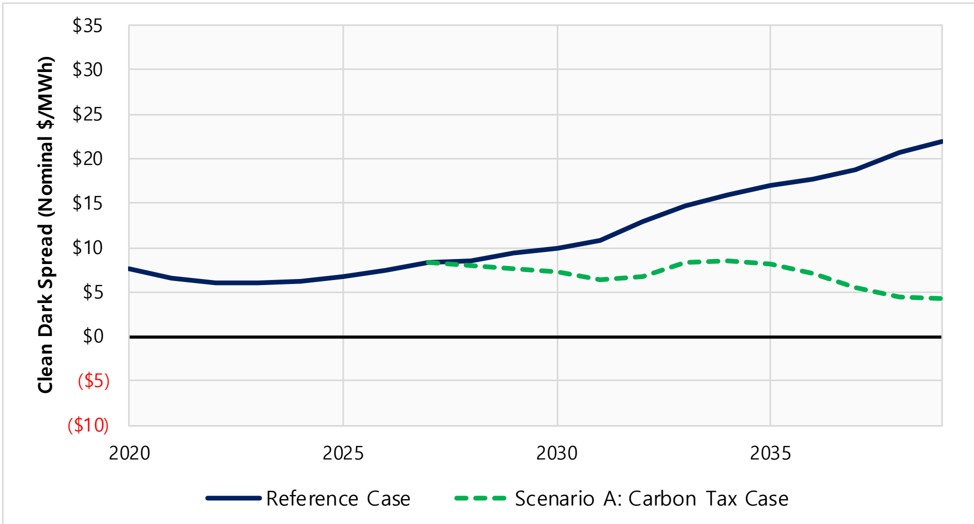
170 IAC 4-7-4(26)

Scenario A used forward curves that incorporated a federal carbon tax beginning in 2028. Portfolio costs increased for all portfolios in this scenario, as the Carbon Tax Case has higher wholesale power price and natural gas prices compared to the Reference Case when the carbon tax is implemented.

The carbon tax is a significant driver of changes in portfolio cost and performance. Portfolio 5, which aggressively transitions the portfolio away from coal by 2030, moves into the top five for PVRR ranking in this scenario, and Portfolios 1 and 2 are among the highest cost portfolios.

The carbon tax impacts portfolios in two key ways. First, clean dark spreads, which are indicative of the marginal economic value of coal units relative to other resources in MISO, shrink as the cost of carbon is added to the variable cost of production of coal. The impact on PVRR is that net margin (energy revenue less fuel, variable O&M, and emission costs) for existing coal assets decreases significantly (30-50%) in the Carbon Tax Case compared to the Reference Case. Figure 8.18 shows the comparison of 7x24 dark spreads in the Reference Case and Carbon Tax Case.

Figure 8.18 | 7x24 Clean Dark Spreads (Nominal $/MWh)



Second, because the grid is not fully decarbonized when the carbon tax is implemented and coal and natural gas units are the marginal price-setting units, wholesale power prices increase in the presence of a carbon tax. Renewable resources benefit from this as their production (MWh) are relatively fixed, but their market revenues will increase with higher prices, all other things equal. Figure 8.19 shows captured energy revenue, which is the generation-weighted average LMP received in the energy market, for the Reference Case and the Carbon Tax Case (Scenario A). The increase in energy revenue in the carbon tax case directly provides benefit to the PVRR in case where new wind and solar is built.

Figure 8.19 | Wind and Solar Captured Revenue, Reference Case vs Carbon Tax Case

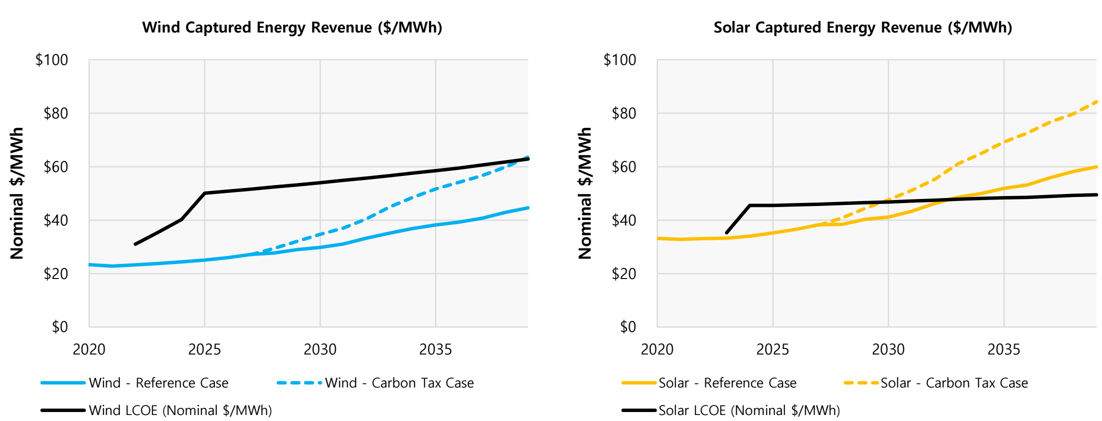


Figure 8.20 shows 20-year PVRR results for all portfolios in Scenario A. Portfolio 3b is the lowest cost portfolio and represents about a $300 million savings from Portfolio 1. Portfolios 5b and 5c, which add

about 2,000 MW of wind and solar through 2030 to replace capacity from coal retirements, benefits from the carbon tax and are in the top 5 lowest cost portfolios in this scenario.

Figure 8.20 | Scenario A PVRR Summary ($Billion)

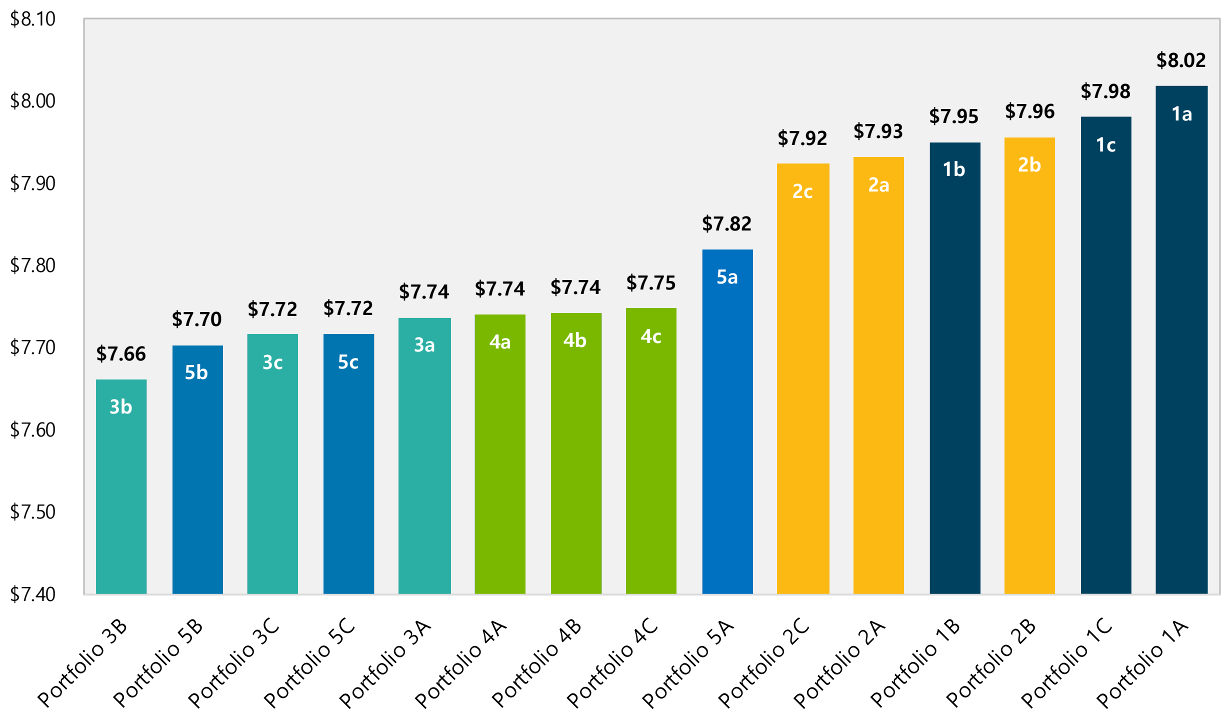
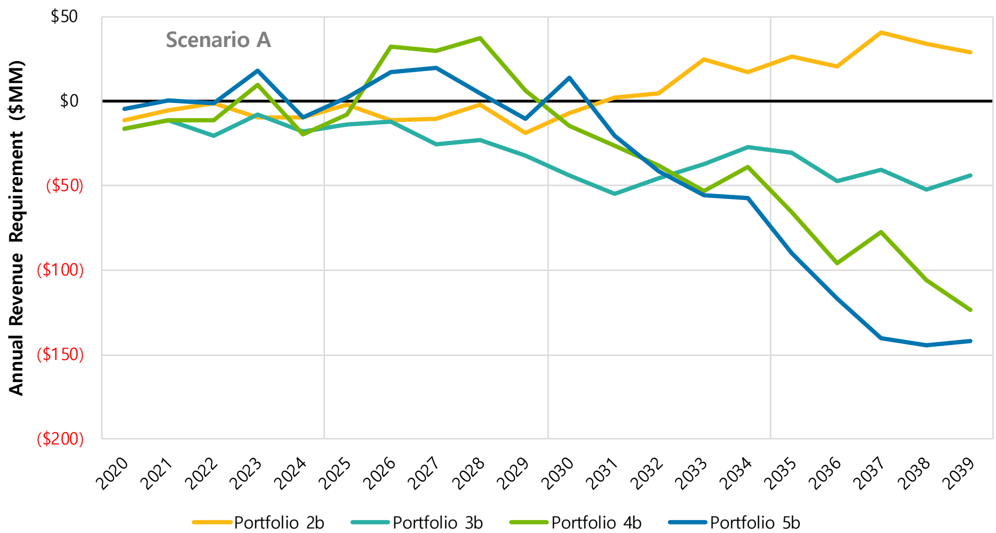


Figure 8.21 shows the annual revenue difference for Portfolios 2b-5b from Portfolio 1b. The revenue requirement increases for Portfolio 5 in the middle of the study when new capacity is added, but the large renewable build benefits from the carbon tax environment and produces annual portfolio cost savings of approximately $200 million (nominal) by the end of the study.

Figure 8.21 | Annual Difference from Portfolio 1b (Nominal $MM)



8.3.3 Scenario B: Carbon Tax + High Gas

170 IAC 4-7-4(26)

Scenario B includes a carbon tax in 2028 and stresses natural gas prices higher (+30-40% per year) starting in the first year of the study. This scenario provides a useful look at whether high natural gas prices, which improve coal net margins, are enough to offset the dispatch cost a carbon tax adds to coal units.

Figure 8.22 contains PVRR results for Scenario B. The results from this scenario show that high gas prices increase the relative cost of Portfolio 5 to other portfolios as the opportunity cost of higher dark spreads 2028 – 2035 outweighs the additional renewable captured revenue in this scenario. Portfolio 1 and 2 remain the highest cost portfolios in this scenario, which indicate that while higher dark spreads in the short term are higher, the long-term impacts of a carbon tax negatively affect a coal-heavy portfolio. Portfolio 3 remains the lowest cost portfolio, showing that portfolio diversification benefits of a mix of resources and locking in low renewable costs early in the study provide long-term benefits in a scenario with a carbon tax and high natural gas prices. Figure 8.23 contains the annual revenue requirement difference from Portfolio 1b for Portfolios 2b – 5b.

Figure 8.24 shows wind and solar captured revenue in $/MWh for the Reference Case and Scenario B. Figure 8.25 shows that dark spreads are higher in Scenario B compared to the Reference Case through 2035, when the carbon tax impact outweighs the benefit coal units see from higher natural gas prices.

Figure 8.22 | Scenario B PVRR Results ($Billion)

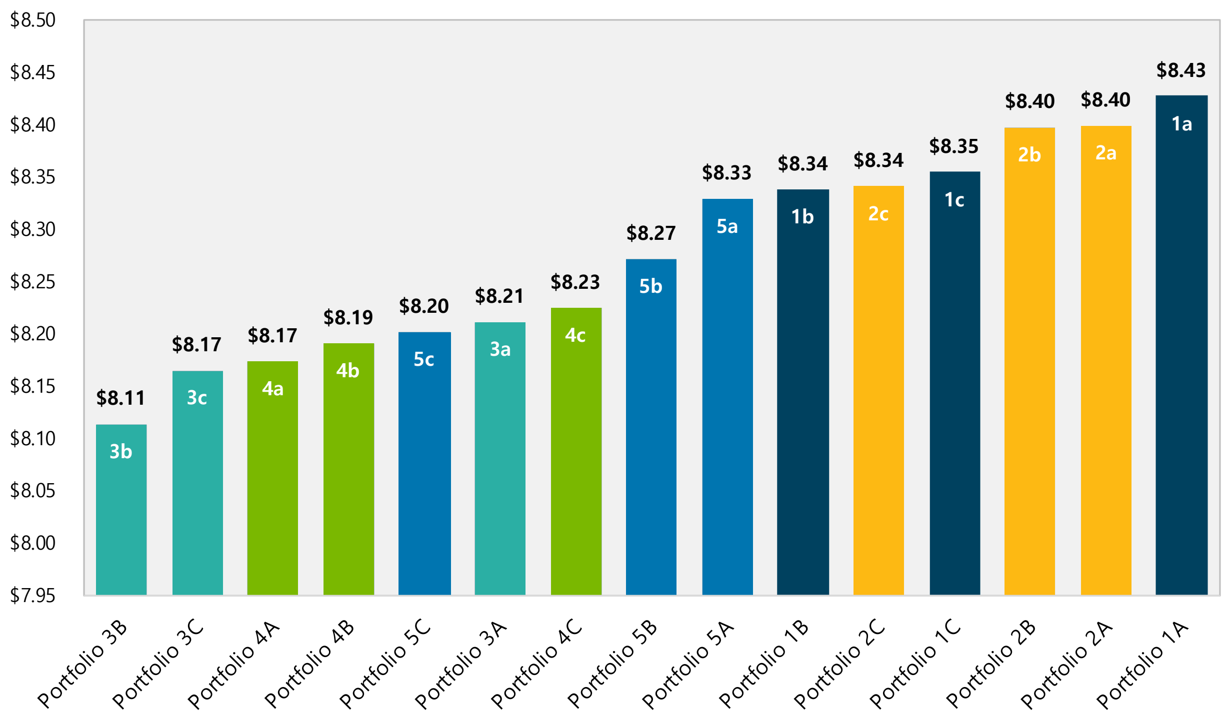


Figure 8.23 | Annual Difference from Portfolio 1b (Nominal $MM)

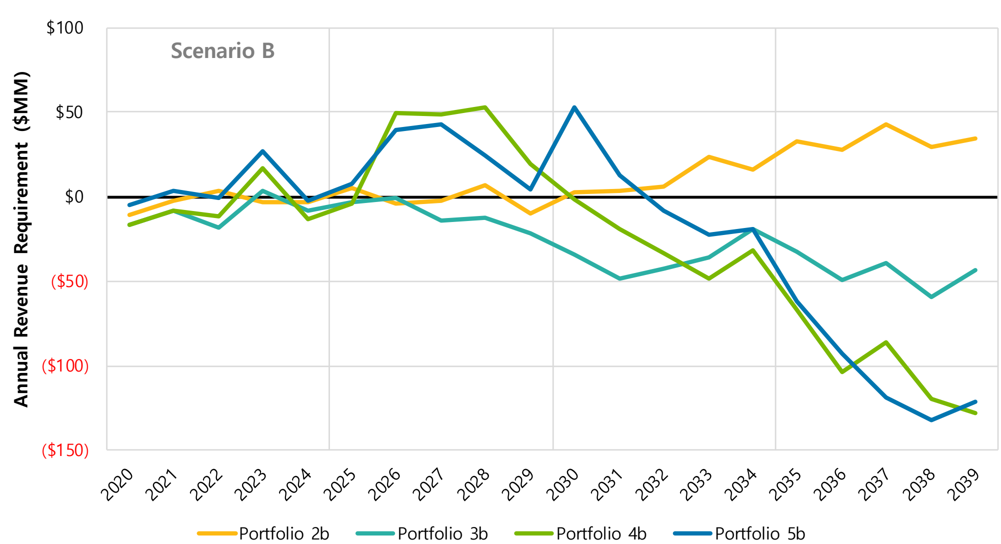


Figure 8.24 | Wind and Solar Captured Revenue, Reference Case vs Scenario B

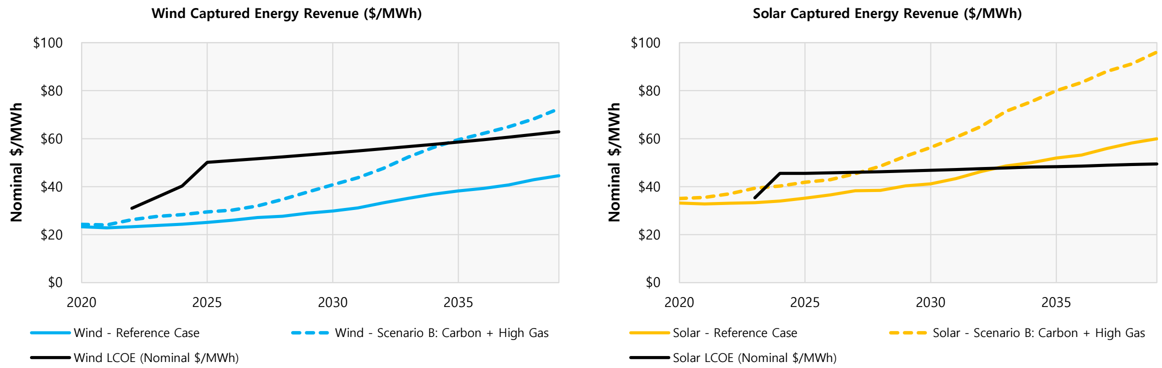
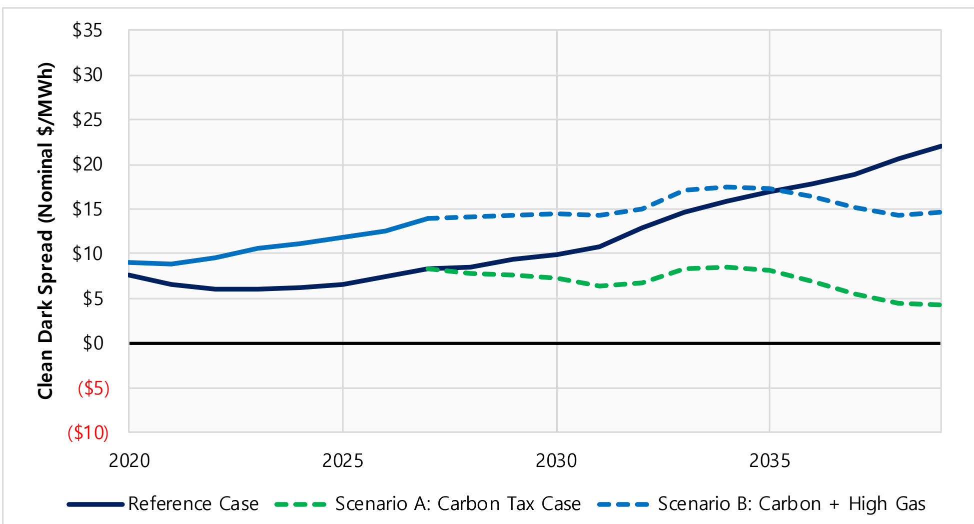


Figure 8.25 | 7x24 Clean Dark Spreads ($Nominal $/MWh)



8.3.4 Scenario C: Carbon Tax + Low Gas + Low Load

170 IAC 4-7-4(26)

Scenario C includes a carbon tax in 2028 and stresses natural gas prices lower (+30-40% per year) starting in the first year of the study. This scenario also includes a low IPL load forecast, which lowers the peak and energy load forecasts. IPL assumed that any excess capacity was sold at the MISO bilateral price estimate.

Figure 8.26 contains PVRR results for Scenario C. The combination of low load, low natural gas prices, and a carbon tax negatively impacts portfolios with coal generation and generally improves the economics of portfolios that contain a balance of natural gas and renewables. Portfolio 5b, which included a fourth DSM bundle and added a 1x1 CCGT in 2026 was the lowest cost portfolio in this scenario, followed by Portfolios 3a-3c. Figure 8.27 contains annual 7x24 clean dark spreads and shows that the combination of low natural gas prices and a carbon tax significantly reduce the economics of any coal in the candidate portfolios.

Figure 8.26 | Scenario C PVRR Summary ($Billion)

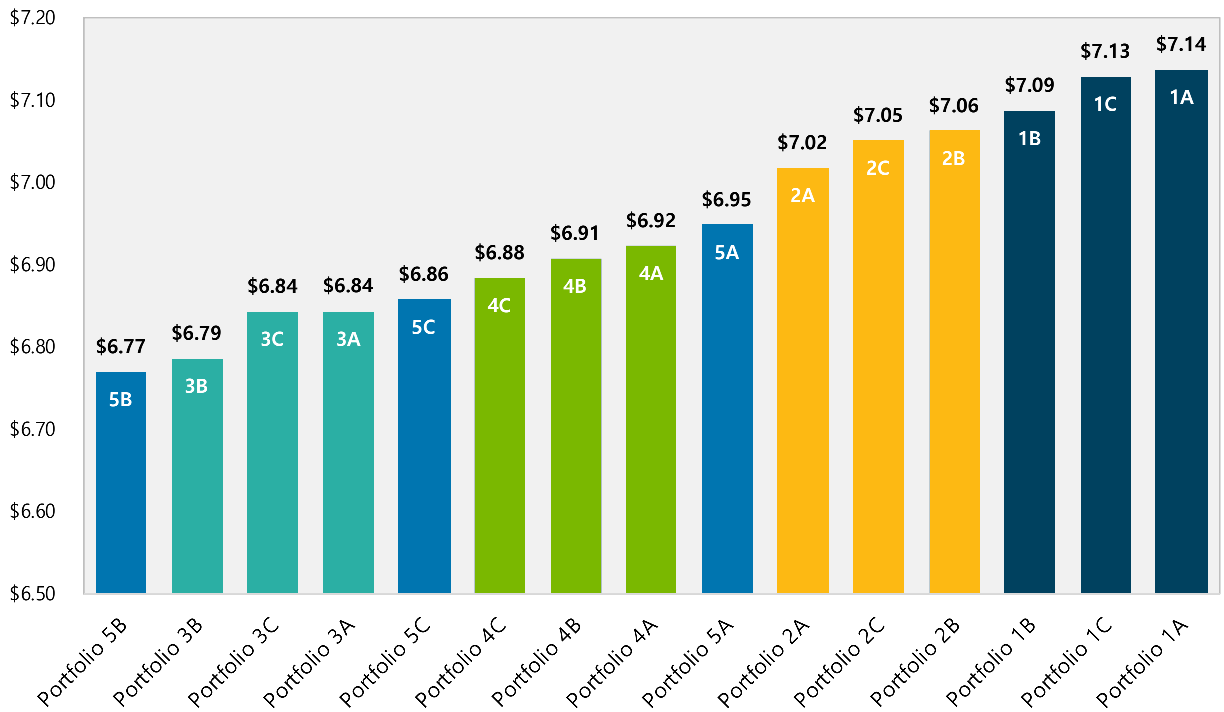
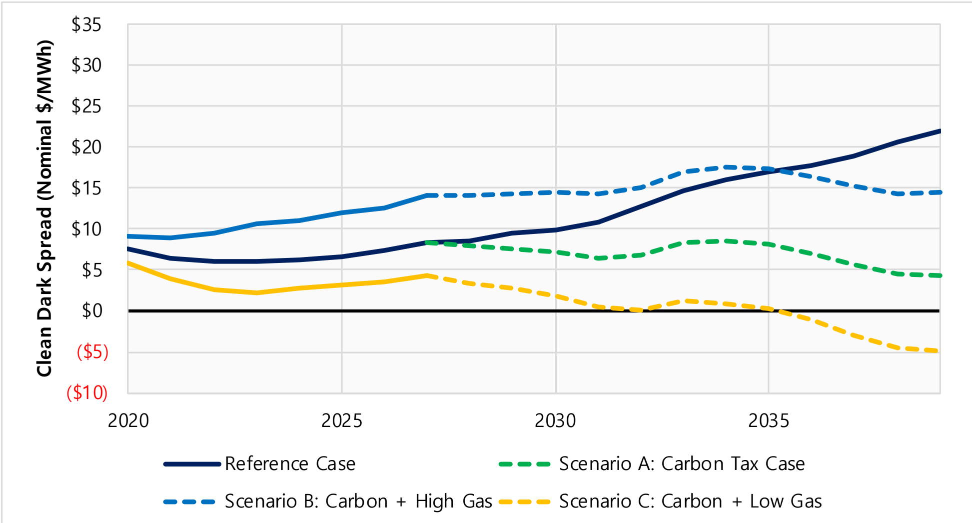


Figure 8.27 | 7x24 Clean Dark Spreads (Nominal $/MWh)



8.3.5 Scenario D: No Carbon Tax + High Gas + High Load

170 IAC 4-7-4(26)

Scenario D represents an increase of 30-40% per year in natural gas prices relative to the Reference Case but does not contain a federal carbon tax. This scenario also includes a high load forecast, which includes higher peak and energy forecasts. New build and retirement decisions were fixed, so any incremental capacity shortfall was covered with capacity market purchases when needed.

This scenario was designed to represent a bookend scenario to evaluate a best-case scenario for the future economics of IPL's coal units. Figure 8.28 contains summary PVRR data for Scenario D. While the cost gap between Portfolios 1 and 3 closes in this scenario, Portfolio 3 remains the lowest cost portfolio as it benefits from a diverse portfolio and retains some coal to hedge against high gas prices. Overall, it highlights the inability of Pete 1 and 2 to earn enough energy and capacity margin to cover operating costs over the remaining life of the assets. Figure 8.29 contains the annual revenue requirement difference from Portfolio 1b for Portfolios 2b – 5b.

Figure 8.28 | Scenario D PVRR Summary ($Billion)

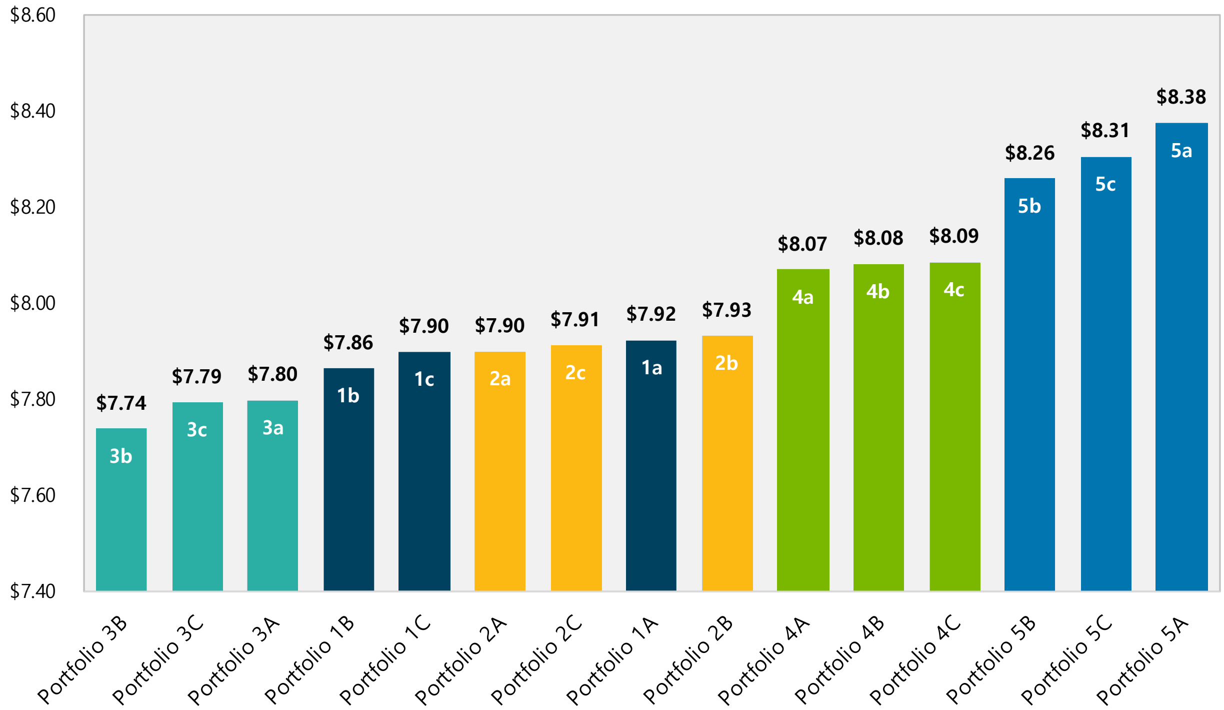


Figure 8.29 | Scenario D: Annual Difference from Portfolio 1b (Nominal $MM)

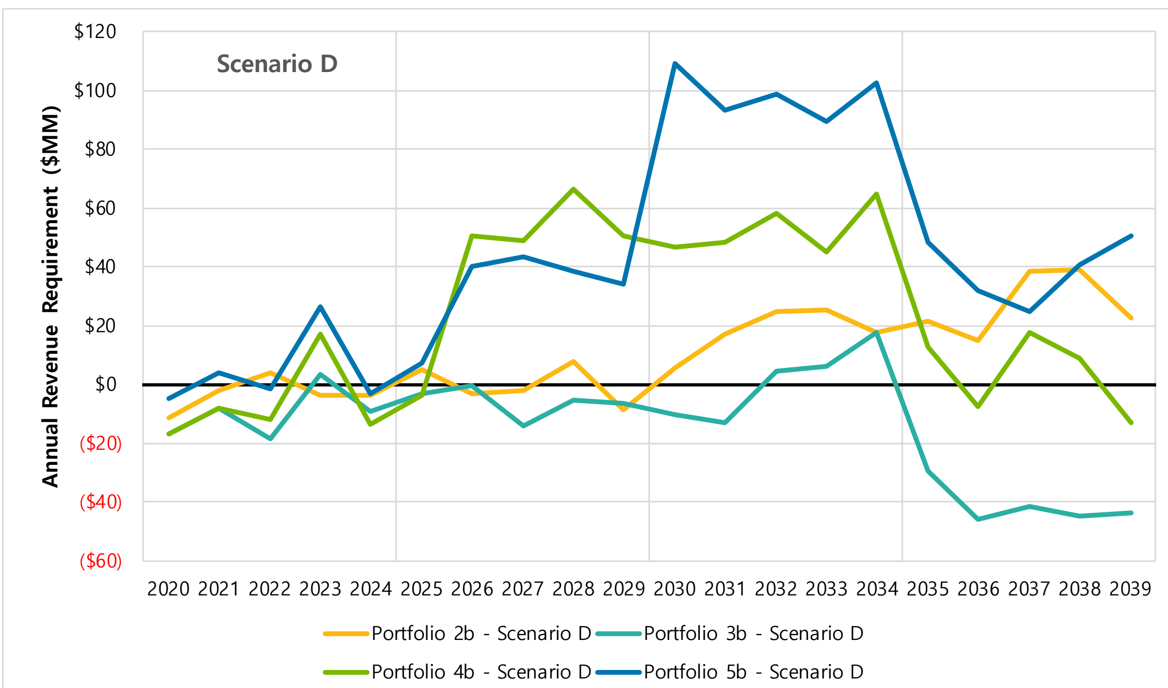


Figure 8.30 contains wind and solar captured revenue for the Reference and Scenario D. As the two charts show, all other things equal, higher natural gas prices benefit renewables with higher priced natural gas units setting the market price in most hours throughout the year. This provides a type of fuel hedge and shows how renewables can provide some level of risk mitigation for long term increases in natural gas prices.

Figure 8.30 | Wind and Solar Captured Revenue, Reference Case vs. Scenario D

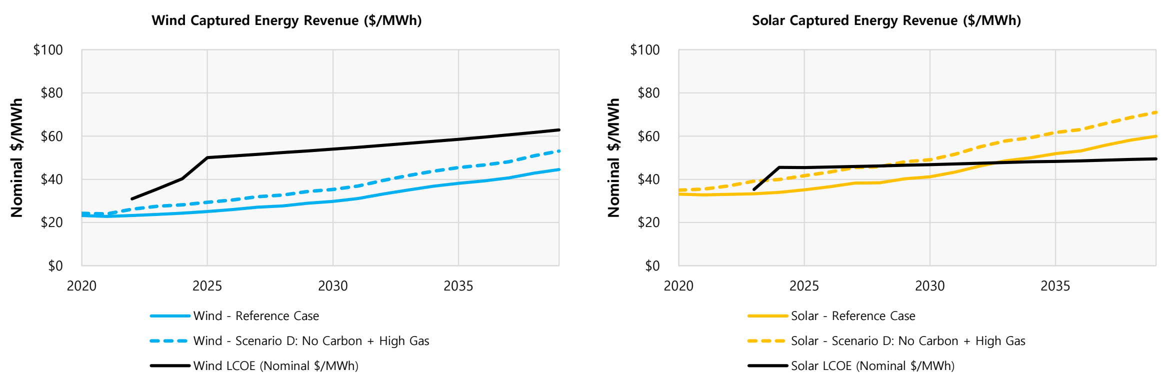
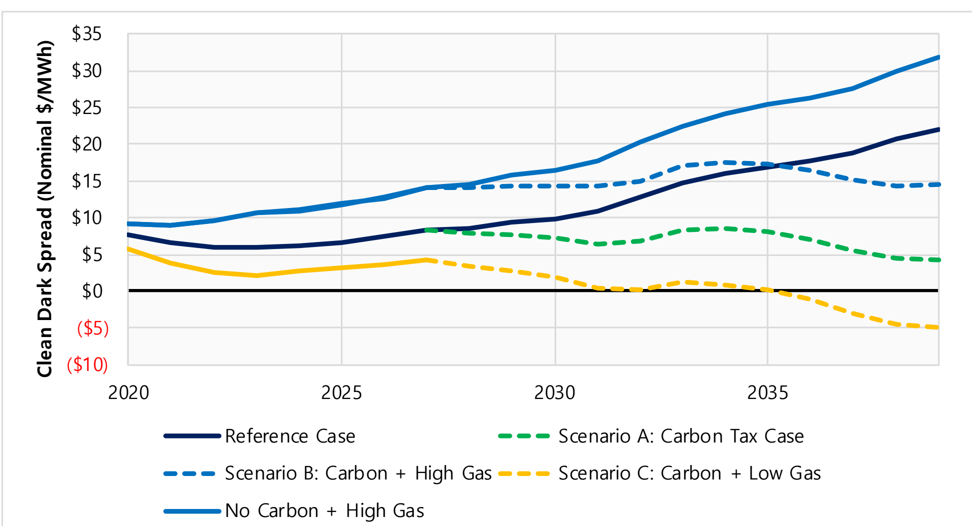


Figure 8.31 shows the 7x24 annual clean dark spreads for all scenarios modeled in this IRP. As the chart shows, Scenario D is effectively the "best case" scenario for coal as coal units are more in the money in this scenario compared to all other alternative scenarios.

Figure 8.31 | 7x24 Clean Dark Spreads



IPL had several key takeaways from analyzing PVRR for each portfolio across the scenarios:

1. **A carbon tax had the single largest impact on changes in PVRR for the portfolios.** As demonstrated from the scenario results, the assumption for a carbon tax resulted in significant changes in the ordering of portfolios on cost. The impact is due to the simultaneous impact of penalizing coal and natural gas generation and increasing the value of renewables, all other things equal. IPL believes that reducing customer exposure to future carbon legislation is an important considering for long term planning. As stated before, the timing and scale of any future carbon legislation could take many forms.

2. **The price of natural gas will continue to be a high impact variable to assess the future viability IPL coal units.** The fundamental shift downward in natural gas prices over the past 10 years due to shale production has put immediate economic pressure on coal assets in MISO and in Indiana. There are market uncertainties and policy uncertainties that play into the forecasted range of natural gas prices in this IRP.

3. **In the short- to mid-term, continuing to pursue a balanced portfolio that is not too reliant on one resource type provides value to customers.** Portfolio 3b, which continues to decrease IPL's reliance on coal, maintains existing natural gas units in the first ten years, and adds wind, renewables, storage, and DSM early performs the best across a wide range of futures and provides opportunities for continued evaluation of the market as the portfolio is implemented.

8.3.6 Cost Metrics

IPL evaluated three (3) specific cost metrics: the 20-year PVRR, Annual Revenue Requirement and a Levelized Rate. The 20 Year PVRR is presented in Figure 8.15 and the Annual Revenue Requirements as compared to Portfolio 1 are shown for each Scenario's result sections (Sections 8.3.1 – 8.3.5). Annual rate impacts for each of the portfolios are driven by the change in annual costs as shown for each of the scenarios above in the annual revenue requirement graphs. The cumulative 20-year rate impact for each portfolio and scenario is summarized in Figure 8.32.

Figure 8.32 | Levelized Rate Impact at 6.486% Discount Rate ($/kWh)

	Reference Case	Scenario A: Carbon Tax Case	Scenario B: Carbon + High Gas	Scenario C: Carbon + Low Gas	Scenario D: No Carbon + High Gas
Portfolio 1a	$0.046	$0.051	$0.053	$0.047	$0.048
Portfolio 2a	$0.045	$0.050	$0.053	$0.046	$0.048
Portfolio 3a	$0.044	$0.049	$0.052	$0.045	$0.047
Portfolio 4a	$0.046	$0.049	$0.052	$0.045	$0.049
Portfolio 5a	$0.047	$0.049	$0.053	$0.045	$0.051
Portfolio 1b	$0.046	$0.051	$0.053	$0.047	$0.048
Portfolio 2b	$0.046	$0.051	$0.054	$0.047	$0.049
Portfolio 3b	$0.045	$0.049	$0.052	$0.045	$0.047
Portfolio 4b	$0.047	$0.049	$0.052	$0.046	$0.049
Portfolio 5b	$0.047	$0.049	$0.053	$0.045	$0.051
Portfolio 1c	$0.047	$0.052	$0.054	$0.048	$0.049
Portfolio 2c	$0.046	$0.051	$0.054	$0.047	$0.049
Portfolio 3c	$0.045	$0.050	$0.053	$0.046	$0.048
Portfolio 4c	$0.047	$0.050	$0.053	$0.046	$0.050
Portfolio 5c	$0.048	$0.050	$0.053	$0.046	$0.051

8.3.7 Risk Metrics

The risk premium metric evaluates the probability weighted average of high cost outcomes less the median. This is an indicator of tail risk for each portfolio. The risk premium was calculated for each production cost run and is summarized in Figure 8.33.

The risk premium trends higher as coal is retired, which can be attributed to several factors. First, coal prices are relatively stable compared to power and natural gas prices, so coal can potentially reduce overall portfolio risk. Second, coal units are dispatchable units and will increase output during high price times and reduce output during low price hours.

Figure 8.33 | Net Present Value of Annual Risk Premium ($MM)

	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
Portfolio 1A	$329	$383	$406	$353	$400
Portfolio 2A	$370	$425	$465	$384	$452
Portfolio 3A	$367	$419	$464	$370	$448
Portfolio 4A	$466	$537	$611	$466	$554
Portfolio 5A	$441	$498	$574	$431	$539
Portfolio 1B	$358	$420	$447	$385	$430
Portfolio 2B	$354	$407	$442	$363	$431
Portfolio 3B	$408	$468	$532	$415	$495
Portfolio 4B	$461	$534	$609	$467	$554
Portfolio 5B	$493	$565	$649	$481	$595
Portfolio 1C	$348	$406	$430	$374	$416
Portfolio 2C	$360	$412	$449	$368	$438
Portfolio 3C	$372	$424	$476	$378	$448
Portfolio 4C	$457	$534	$612	$464	$554
Portfolio 5C	$442	$507	$584	$448	$543

Figure 8.34 contains risk-adjusted PVRRs, which means that the risk premium in Figure 8.33 was added to the mean expected value PVRR. Adding the risk premium puts all portfolios on equal footing and allows IPL to directly incorporate risk into the decision-making process. When adjusted for risk, Portfolio 3 is the lowest cost option on a risk-adjusted basis.

Figure 8.34 | Risk-Adjusted PVRR: Expected Value (Mean) + Risk Premium ($MM)

	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
Portfolio 1A	$7,544	$8,401	$8,833	$7,489	$8,324
Portfolio 2A	$7,502	$8,356	$8,865	$7,401	$8,351
Portfolio 3A	$7,383	$8,156	$8,676	$7,213	$8,246
Portfolio 4A	$7,761	$8,278	$8,784	$7,388	$8,623
Portfolio 5A	$7,941	$8,317	$8,904	$7,379	$8,915
Portfolio 1B	$7,533	$8,370	$8,785	$7,472	$8,294
Portfolio 2B	$7,542	$8,363	$8,840	$7,425	$8,363
Portfolio 3B	$7,384	$8,129	$8,646	$7,201	$8,234
Portfolio 4B	$7,754	$8,277	$8,800	$7,374	$8,636
Portfolio 5B	$7,892	$8,268	$8,921	$7,250	$8,854
Portfolio 1C	$7,571	$8,387	$8,785	$7,502	$8,315
Portfolio 2C	$7,551	$8,335	$8,791	$7,418	$8,350
Portfolio 3C	$7,407	$8,139	$8,642	$7,221	$8,242
Portfolio 4C	$7,726	$8,281	$8,837	$7,347	$8,640
Portfolio 5C	$7,893	$8,223	$8,786	$7,305	$8,849

IPL evaluated "potential downside", which represents the median minus the probability-weighted average of outcomes below the median (left side of distribution), along with high cost tail risk across all scenarios. Figure 8.35 to Figure 8.39 contain the expected value (mean/average) PVRR, the risk premium, and the downside potential. Considering the full distribution of outcomes provides a balanced view of the variability of PVRR results across scenarios.

Figure 8.35 | PVRR Range: Reference Case ($MM)

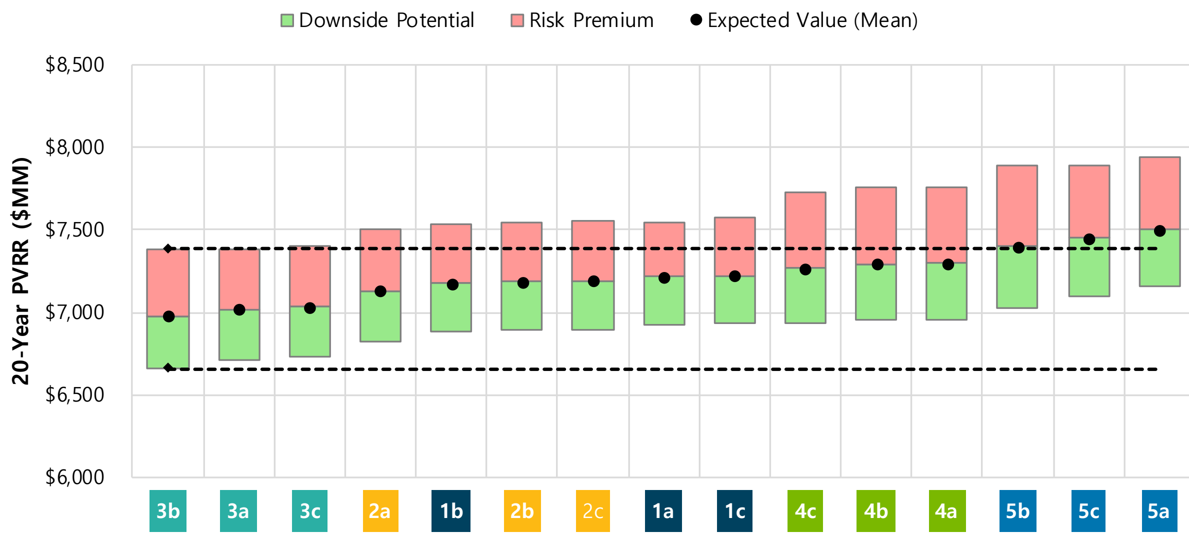


Figure 8.36 | PVRR Range, Scenario A: Carbon Tax Case ($MM)

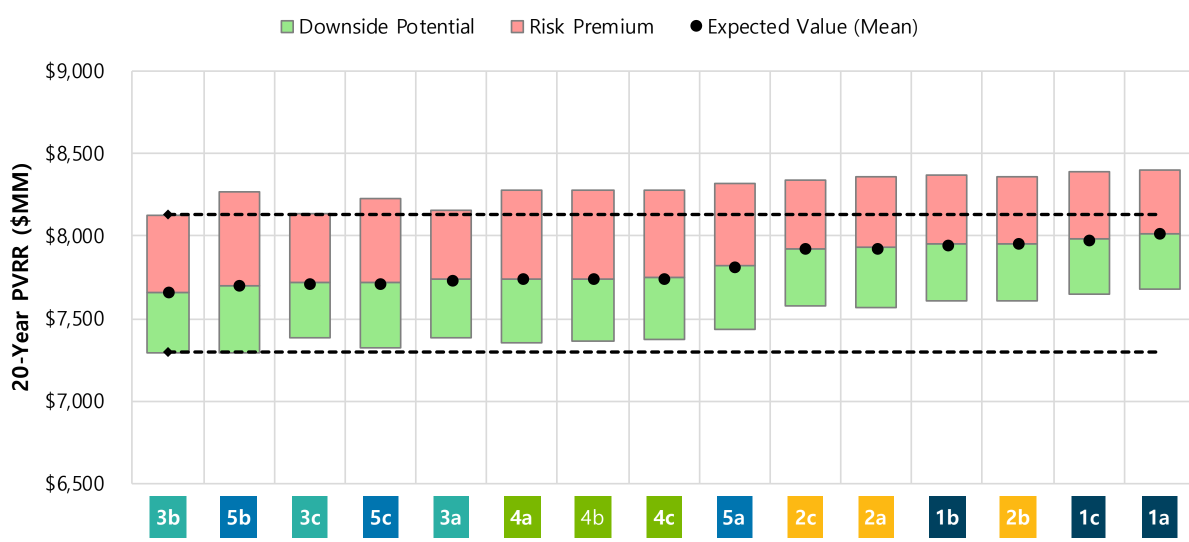


Figure 8.37 | PVRR Range, Scenario B: Carbon Tax + High Gas ($MM)

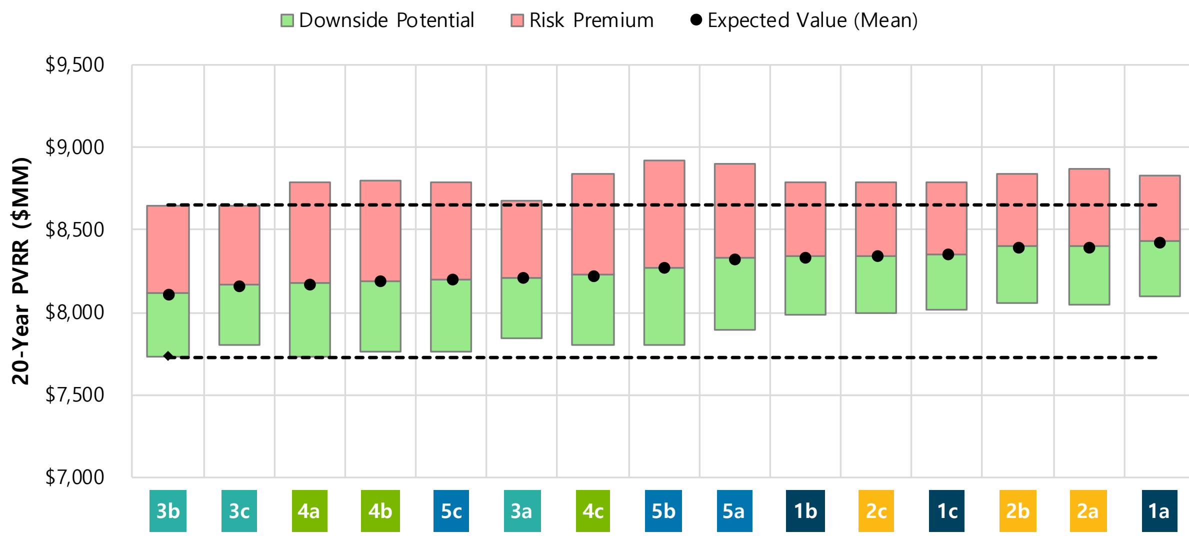


Figure 8.38 | PVRR Range, Scenario C: Carbon Tax + Low Gas + Low Load ($MM)

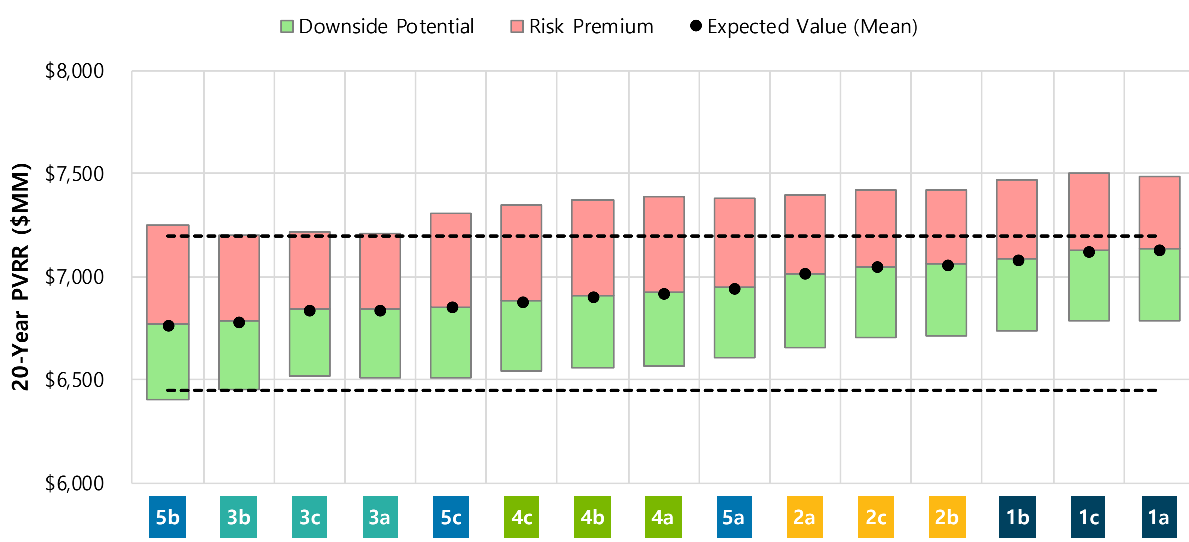
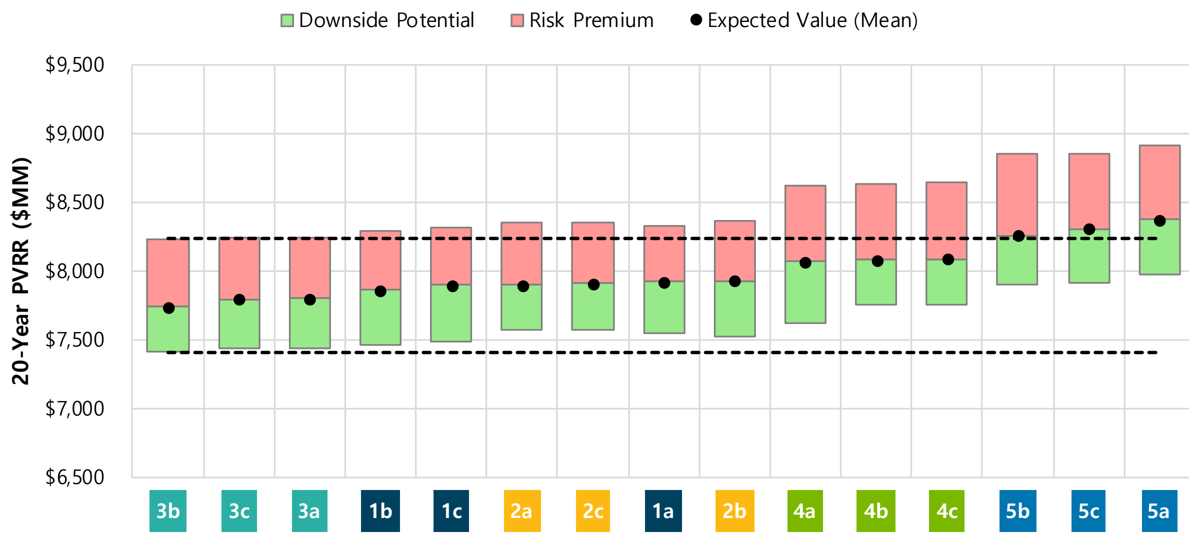
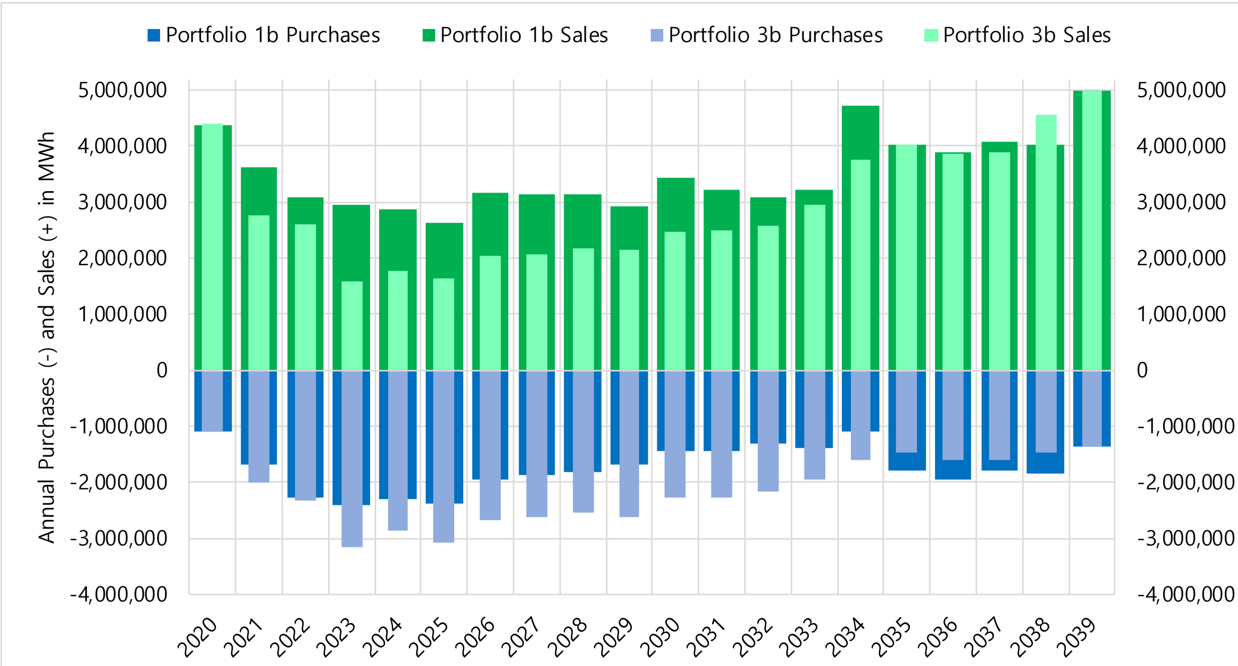


Figure 8.39 | PVRR Range, Scenario D: No Carbon Tax + High Gas + High Load ($MM)



Looking at market purchases and sales, or total market interaction, provides another perspective on risk exposure. While there is not a "correct" level of market interaction, this is a useful metric to compare the relative risk of portfolios and the ability to serve hourly load and not simply produce enough energy on an annual basis. Figure 8.40 is an example of hourly market interactions summed up annually. It compares Portfolio 3b to Portfolio 1b in the Reference Case. The portfolios are identical in the first year, but by 2021 Portfolio 3b has slightly more energy purchases and notably less energy sales due to the early retirement of Pete 1. Similar market interactions charts for each portfolio and scenario can be found in Attachment 8.3.

Figure 8.40 | Annual Market Interaction of Portfolio 3b Compared to Portfolio 1b for the Reference Case



Averaging the annual purchases and sales and summing the absolute value of those averages provides a simplified single number representing market interaction that can be used for comparison between portfolios. Figure 8.41 displays this metric for each portfolio and highlights the lowest risk portfolio in each group for each scenario. Less market interaction implies less risk. Portfolios 2 and 3 have the least market interaction, and Portfolios 1 or 5 tend to the have most market interaction.

Figure 8.41 | Average Market Interaction by Portfolio and Scenario

	Market Interaction in Millions of MWh, |Purchases| + |Sales|				
	20-Year Average (2020 - 2039)				
	Reference Case	Scenario A	Scenario B	Scenario C	Scenario D
Portfolio 1a	5.1	5.4	4.7	5.8	4.4
Portfolio 2a	4.8	5.4	4.6	5.7	4.3
Portfolio 3a	4.7	5.1	4.6	5.1	4.4
Portfolio 4a	5.4	5.5	5.3	5.5	5.3
Portfolio 5a	5.4	5.4	5.3	5.6	5.4
Portfolio 1b	5.2	5.7	5.0	5.9	4.6
Portfolio 2b	4.9	5.3	4.6	5.5	4.4
Portfolio 3b	5.0	5.4	4.9	5.4	4.7
Portfolio 4b	5.5	5.4	5.2	5.5	5.3
Portfolio 5b	5.6	5.6	5.5	5.6	5.7
Portfolio 1c	5.4	5.7	5.0	5.9	4.6
Portfolio 2c	5.1	5.4	4.8	5.5	4.5
Portfolio 3c	4.9	5.1	4.7	5.1	4.6
Portfolio 4c	5.4	5.5	5.2	5.4	5.2
Portfolio 5c	5.7	5.7	5.5	5.9	5.5

8.3.8 Environmental Metrics

170 IAC 4-7-6(b)(3)(C)

Air Emissions

Figure 8.42 contains a comparison of metrics for air emissions for all portfolios in the Reference Case. Metrics for all portfolios are shown as 20-year averages for the study period (2020 – 2039). Coal generation produces the most emissions in IPL's fleet, so average emissions decrease from Portfolios 1 to 5 as more coal units are retired and replaced with renewables, storage, and gas. Each portfolio, including Portfolio 1 with age-based retirements, shows a significant reduction in all air emissions compared to the historic baseline.

Figure 8.42 | Portfolio Air Emissions from Reference Case Scenario

	CO_2 (million short-tons)	CO_2 Intensity (short-tons/MWh)	NO_x (short-tons)	SO_2 (short-tons)
2010 - 2012 Baseline (3-year average)	**16.1**	**1.05**	**14,255**	**53,107**
	20-Year Average (2020 - 2039)			
Portfolio 1a	11.9	0.75	8,028	10,972
Portfolio 2a	11.0	0.73	7,120	10,477
Portfolio 3a	9.5	0.64	6,371	9,577
Portfolio 4a	7.0	0.46	5,152	6,038
Portfolio 5a	5.6	0.38	2,991	3,582
Portfolio 1b	11.9	0.74	8,028	10,972
Portfolio 2b	11.1	0.72	7,124	10,477
Portfolio 3b	9.5	0.63	6,371	9,577
Portfolio 4b	7.0	0.47	5,164	6,039
Portfolio 5b	5.8	0.41	3,014	3,583
Portfolio 1c	11.9	0.74	8,028	10,972
Portfolio 2c	11.0	0.71	7,120	10,477
Portfolio 3c	9.5	0.64	6,371	9,577
Portfolio 4c	7.1	0.49	5,182	6,039
Portfolio 5c	5.7	0.38	2,988	3,583

Figure 8.43 shows the air emissions of the portfolios in Scenario A, the Carbon Case. A carbon tax results in lower coal capacity factors which further reduces air emissions relative to the Reference Case.

Figure 8.43 | Portfolio Air Emissions from Scenario A: Carbon Case

	CO_2 (million short-tons)	CO_2 Intensity (short-tons/MWh)	NO_x (short-tons)	SO_2 (short-tons)
2010 - 2012 Baseline (3-year average)	**16.1**	**1.05**	**14,255**	**53,107**
Portfolio 1a	10.0	0.71	6,547	8,653
Portfolio 2a	9.3	0.69	5,722	8,203
Portfolio 3a	8.0	0.59	5,085	7,438
Portfolio 4a	6.3	0.43	4,265	5,059
Portfolio 5a	5.6	0.38	2,952	3,552
Portfolio 1b	10.0	0.70	6,547	8,653
Portfolio 2b	9.3	0.68	5,726	8,203
Portfolio 3b	8.0	0.58	5,085	7,438
Portfolio 4b	6.3	0.44	4,277	5,059
Portfolio 5b	5.8	0.41	2,974	3,553
Portfolio 1c	10.0	0.70	6,547	8,653
Portfolio 2c	9.3	0.67	5,722	8,203
Portfolio 3c	8.0	0.59	5,085	7,438
Portfolio 4c	6.4	0.46	4,294	5,060
Portfolio 5c	5.7	0.38	2,950	3,552

Non-Air Impacts (Water)

Retiring Pete Units 1 and 2 reduces the actual intake flow of water more than 67%. Retiring all four Pete Units results in the elimination of 354 million gallons per day ("MGD") of water withdrawal from the river (100% reduction).

8.4 Sensitivities

8.4.1 Capital Cost Sensitivity

The capital cost sensitivity analysis was designed to evaluate the impact of changing costs for renewables and storage for each portfolio relative to the base set of cost estimates. The deterministic sensitivity uses the financial revenue requirement model to provide insight into how portfolio costs change if resource decisions are made and if the actual cost is higher or lower than expected.

This analysis can help answer two questions:

1. How low would capital costs need to be to make Portfolio 5, the most aggressive transition case, the lowest cost portfolio in the Reference Case and Carbon Tax Case (Scenario A)?
2. For the lowest cost portfolio, would higher than expected renewable and storage costs cause that portfolio to be higher cost than Portfolio 1 with no economic retirements of coal units?

Figure 8.44 shows that even with a significant decrease in capital costs for renewables and storage, Portfolio 5 is not the lowest cost portfolio in the Reference Case. The figure also shows that even with a significant increase in capital costs, the PVRR for Portfolio 3 is lower than or equal to the PVRR of the mean PVRR for Portfolio 1 using base cost assumptions. Figure 8.45 shows the detailed PVRR results for the sensitivity analysis for the Reference Case scenario.

Figure 8.44 | Capital Cost Sensitivity, Reference Case PVRR Range ($MM)

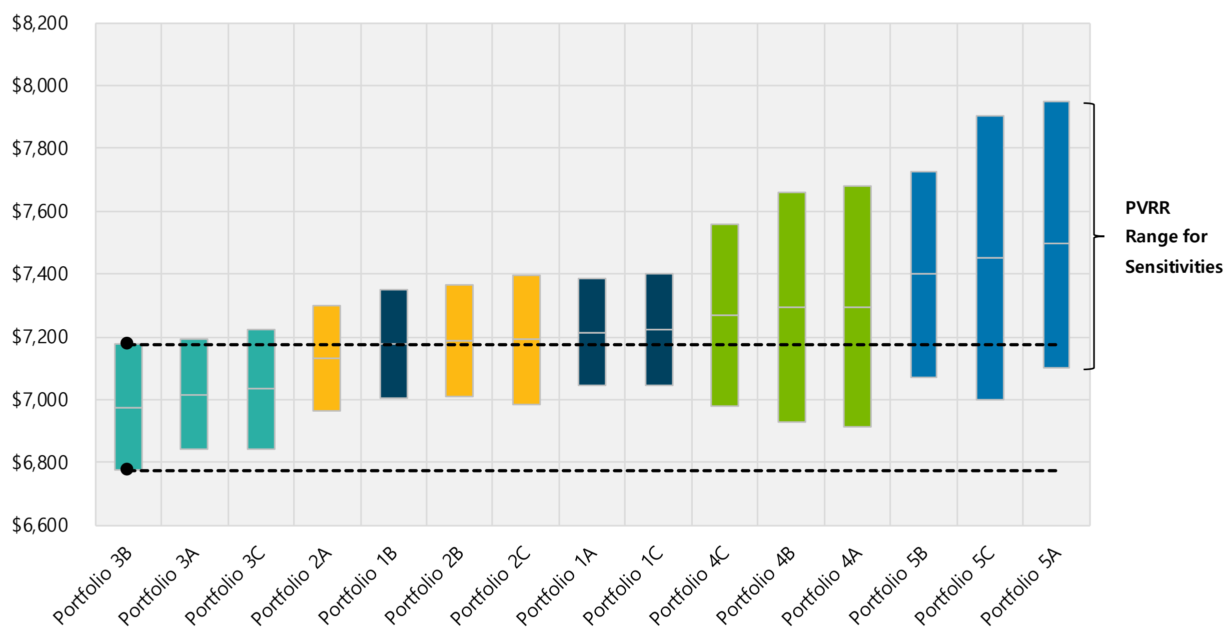


Figure 8.45 | Capital Cost Sensitivity, Reference Case PVRR Summary ($MM)

	Percent Change by 2030		PVRR w/ Base Capital Costs ↓	Percent Change by 2030	
	-30%	**-15%**		**+15%**	**+30%**
Portfolio 3b	$6,775	$6,874	$6,976	$7,077	**$7,177**
Portfolio 3a	$6,841	$6,927	$7,016	$7,105	$7,191
Portfolio 3c	$6,843	$6,938	$7,034	$7,131	$7,225
Portfolio 2a	$6,965	$7,049	$7,132	$7,214	$7,298
Portfolio 1b	$7,004	$7,091	$7,176	$7,261	$7,348
Portfolio 2b	$7,010	$7,100	$7,188	$7,276	$7,366
Portfolio 2c	$6,986	$7,089	$7,191	$7,292	$7,396
Portfolio 1a	$7,043	$7,130	$7,215	$7,300	$7,387
Portfolio 1c	$7,043	$7,134	$7,223	$7,312	$7,403
Portfolio 4c	$6,978	$7,121	$7,269	$7,417	$7,560
Portfolio 4b	$6,928	$7,107	$7,293	$7,478	$7,658
Portfolio 4a	$6,912	$7,100	$7,295	$7,490	$7,678
Portfolio 5b	$7,073	$7,234	$7,400	$7,565	$7,726
Portfolio 5c	$7,001	$7,224	$7,452	$7,679	$7,902
Portfolio 5a	**$7,100**	$7,309	$7,500	$7,741	$7,950

Figure 8.46 shows results of the sensitivity analysis for Scenario A, which is the Carbon Tax Case. The results from this scenario indicate two important takeaways. First, the results show that decreases in capital costs relative to base forecasts show that even small decreases in capital costs would make Portfolios 4 and 5 the lowest cost portfolios in this scenario. This combination of scenario analysis and sensitivity analysis effectively identifies market indicators or "sign posts" that IPL can monitor to see how portfolio strategies could change through time. A federal tax on carbon combined with capital costs beating expectations could cause IPL to move retirement dates for Pete 3 and 4 forward. Figure 8.46 also shows the robustness of Portfolio 3 compared to Portfolios 1 and 2, as the upper end of the PVRR range for Portfolio 3 is still lower than the expected PVRR for Portfolios 1 and 2. Figure 8.47 contains the detailed PVRR results from this analysis.

Figure 8.46 | Capital Cost Sensitivity, Scenario A (Carbon Case) PVRR Range ($MM)

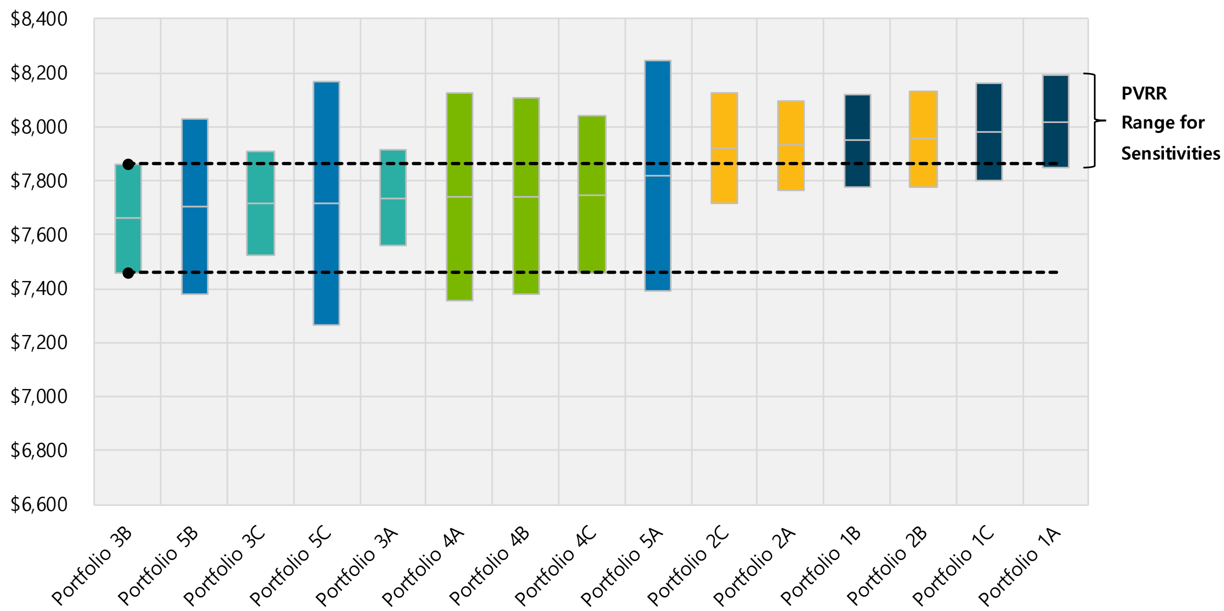


Figure 8.47 | Capital Cost Sensitivity, Scenario A (Carbon Case) PVRR Summary ($MM)

	Percent Change by 2030 -30%	Percent Change by 2030 -15%	PVRR w/ Base Capital Costs ↓	Percent Change by 2030 +15%	Percent Change by 2030 +30%
Portfolio 3b	$7,460	$7,560	$7,661	$7,763	$7,862
Portfolio 5b	**$7,377**	**$7,538**	$7,703	$7,869	$8,030
Portfolio 3c	$7,524	$7,619	$7,716	$7,812	$7,907
Portfolio 5c	$7,266	$7,489	$7,716	$7,944	$8,166
Portfolio 3a	$7,562	$7,648	$7,737	$7,826	$7,912
Portfolio 4a	$7,357	$7,546	$7,740	$7,935	$8,123
Portfolio 4b	$7,377	$7,538	$7,742	$7,928	$8,107
Portfolio 4c	$7,456	$7,599	$7,747	$7,896	$8,039
Portfolio 5a	$7,394	$7,603	$7,819	$8,035	$8,244
Portfolio 2c	$7,719	$7,822	$7,923	$8,025	$8,128
Portfolio 2a	$7,765	$7,849	$7,932	$8,014	$8,098
Portfolio 1b	$7,778	$7,865	$7,950	$8,035	$8,122
Portfolio 2b	$7,778	$7,868	$7,956	$8,044	$8,134
Portfolio 1c	$7,800	$7,891	$7,980	$8,069	$8,160
Portfolio 1a	$7,846	$7,933	$8,018	$8,103	$8,190

8.4.2 MISO Capacity Price Sensitivity

In addition to capturing uncertainty in future MISO capacity prices via stochastic simulation, IPL also ran a deterministic sensitivity analysis on capacity prices with predefined price curves against the fixed net capacity position for each portfolio.

This sensitivity analysis can assess two kinds of risk:

(1) If IPL does not retire units early and maintains a net long position through 2031, what is the risk to customers that bilateral and MISO auction clearing prices for capacity remain low?

(2) If IPL does retire units early and capacity prices increase significantly due to market rule changes, accelerated retirements in Indiana by multiple utilities, or other factors, what opportunity cost for capacity market sales is the company giving up by retiring units? And does this risk result in Portfolio 1 being the lowest cost portfolio?

Figure 8.48 contains results of the analysis for Portfolios 1a-3a from the Reference Case. The results show that even if IPL values the excess capacity position in Portfolio 1 at CONE for a new CT, Portfolio 3 is still the lower cost portfolio. Additionally, a low capacity price forecast adds an additional $45 million to the PVRR of Portfolio 1.

Overall, the results indicate that even at a very high valuation of excess capacity, Portfolio 1 remains a higher cost portfolio compared to Portfolio 3.

Figure 8.48 | Reference Case PVRR with Capacity Price Sensitivities (PVRR, $MM)

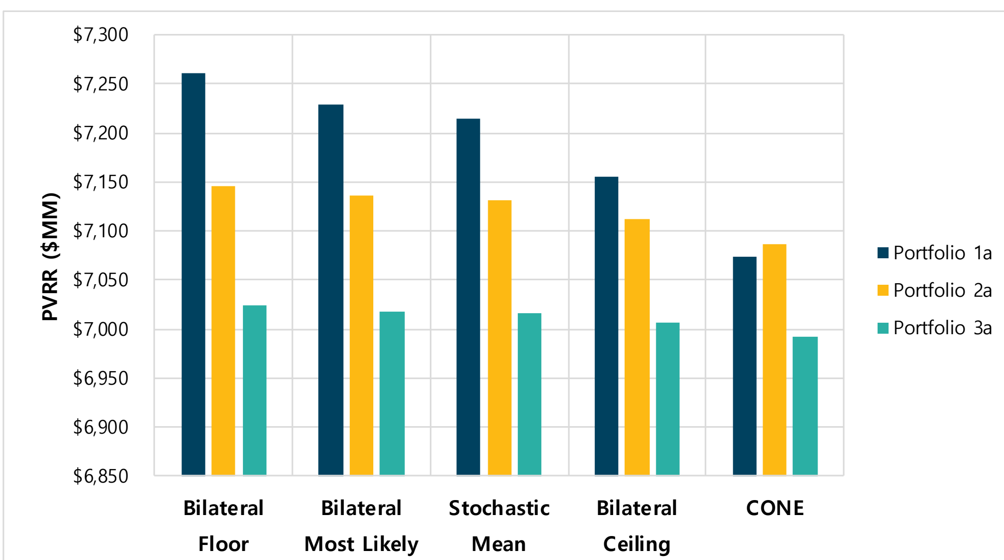


Figure 8.49 | Capacity Price Sensitivity, Reference Case (PVRR, $MM)

	Bilateral Floor	Bilateral Most Likely	[Base] Stochastic Mean	Bilateral Ceiling	CONE
Portfolio 1a	$7,260	$7,229	$7,215	$7,156	$7,074
Portfolio 2a	$7,146	$7,136	$7,132	$7,113	$7,087
Portfolio 3a	$7,024	$7,018	$7,016	$7,006	$6,993
Portfolio 4a	$7,304	$7,298	$7,295	$7,284	$7,269
Portfolio 5a	$7,508	$7,503	$7,500	$7,489	$7,475
Portfolio 1b	$7,221	$7,190	$7,176	$7,116	$7,035
Portfolio 2b	$7,203	$7,193	$7,188	$7,169	$7,144
Portfolio 3b	$6,983	$6,978	$6,976	$6,966	$6,953
Portfolio 4b	$7,301	$7,295	$7,293	$7,281	$7,267
Portfolio 5b	$7,408	$7,402	$7,400	$7,389	$7,375
Portfolio 1c	$7,223	$7,223	$7,223	$7,223	$7,223
Portfolio 2c	$7,191	$7,191	$7,191	$7,191	$7,191
Portfolio 3c	$7,034	$7,034	$7,034	$7,034	$7,034
Portfolio 4c	$7,269	$7,269	$7,269	$7,269	$7,269
Portfolio 5c	$7,452	$7,452	$7,452	$7,452	$7,452

Figure 8.50 | Carbon Tax Case PVRR with Capacity Price Sensitivities (PVRR, $MM)

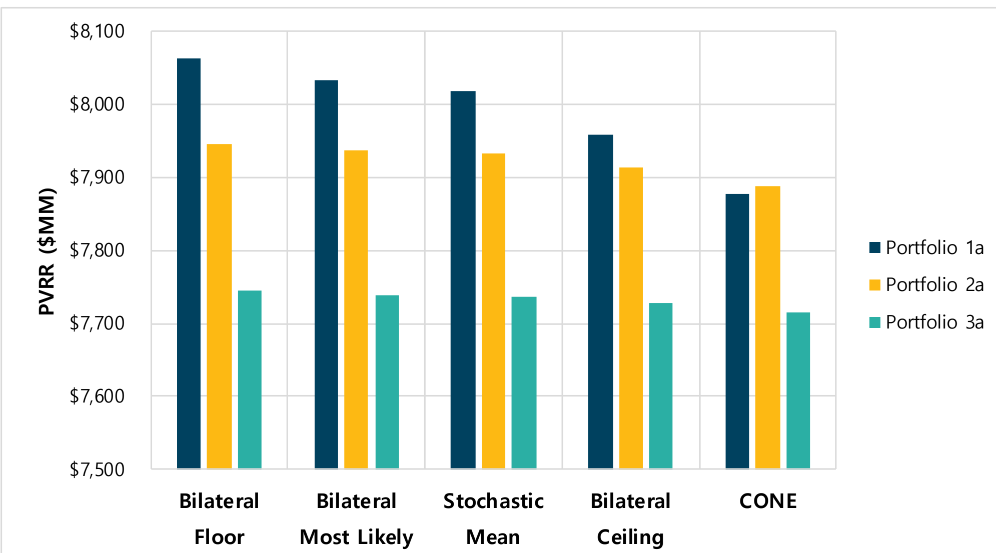


Figure 8.51 | Capacity Price Sensitivity, Carbon Tax Case (PVRR, $MM)

	Bilateral Floor	Bilateral Most Likely	[Base] Stochastic Mean	Bilateral Ceiling	CONE
Portfolio 1a	$8,063	$8,032	$8,018	$7,959	$7,877
Portfolio 2a	$7,946	$7,936	$7,932	$7,913	$7,887
Portfolio 3a	$7,745	$7,739	$7,737	$7,727	$7,714
Portfolio 4a	$7,749	$7,743	$7,740	$7,729	$7,715
Portfolio 5a	$7,828	$7,822	$7,819	$7,809	$7,795
Portfolio 1b	$7,995	$7,964	$7,950	$7,891	$7,809
Portfolio 2b	$7,970	$7,960	$7,956	$7,937	$7,911
Portfolio 3b	$7,669	$7,664	$7,661	$7,651	$7,638
Portfolio 4b	$7,751	$7,745	$7,742	$7,731	$7,717
Portfolio 5b	$7,712	$7,706	$7,703	$7,693	$7,679
Portfolio 1c	$7,980	$7,980	$7,980	$7,980	$7,980
Portfolio 2c	$7,923	$7,923	$7,923	$7,923	$7,923
Portfolio 3c	$7,716	$7,716	$7,716	$7,716	$7,716
Portfolio 4c	$7,747	$7,747	$7,747	$7,747	$7,747
Portfolio 5c	$7,716	$7,716	$7,716	$7,716	$7,716

8.4.3 Wind Capacity Factor Sensitivity

The wind capacity factor sensitivity analysis fixed the captured revenue rate ($/MWh from model results) and changed the volume based on a change to the assumed annual capacity factor. The goal is to evaluate the impact of lower production from actual wind farms relative to modeled wind in this IRP. Total energy market revenues from new wind impacts PVRR and is a significant source of uncertainty for any intermittent resource.

Figure 8.52 shows PVRR results from the Reference Case scenario. Results show that even if new wind was assumed to only have a 30% annual capacity factor, Portfolio 3 is still a lower cost portfolio compared to Portfolio 1. Because Portfolios 4 and 5 add up to 500 MW of wind starting in 2022, the PVRR is more sensitive to changes in capacity factor. Every 2% decrease in the annual wind capacity factor increases the PVRR by approximately $40-50 million for these portfolios.

Figure 8.52 | Wind Capacity Factor Sensitivity, Reference Case (PVRR, $MM)

	Wind Annual Capacity Factor →								
	46%	44%	Base (42%) ↓	40%	38%	36%	34%	32%	30%
Portfolio 3b	$6,959	$6,968	$6,976	$6,987	$6,996	$7,005	$7,014	$7,024	$7,033
Portfolio 3a	$6,991	$7,004	$7,016	$7,032	$7,046	$7,059	$7,073	$7,087	$7,101
Portfolio 3c	$7,012	$7,024	$7,034	$7,049	$7,061	$7,073	$7,086	$7,098	$7,110
Portfolio 2a	$7,128	$7,130	$7,132	$7,134	$7,136	$7,138	$7,140	$7,142	$7,144
Portfolio 1b	$7,172	$7,174	$7,176	$7,178	$7,180	$7,182	$7,184	$7,186	$7,187
Portfolio 2b	$7,179	$7,184	$7,188	$7,194	$7,199	$7,203	$7,208	$7,213	$7,218
Portfolio 2c	$7,180	$7,186	$7,191	$7,198	$7,204	$7,210	$7,215	$7,221	$7,227
Portfolio 1a	$7,208	$7,212	$7,215	$7,219	$7,223	$7,227	$7,230	$7,234	$7,238
Portfolio 1c	$7,217	$7,221	$7,223	$7,227	$7,230	$7,233	$7,237	$7,240	$7,243
Portfolio 4c	$7,222	$7,248	$7,269	$7,299	$7,325	$7,350	$7,376	$7,401	$7,427
Portfolio 4b	$7,234	$7,266	$7,293	$7,330	$7,362	$7,394	$7,426	$7,458	$7,489
Portfolio 4a	$7,228	$7,265	$7,295	$7,338	$7,375	$7,411	$7,448	$7,484	$7,521
Portfolio 5b	$7,355	$7,379	$7,400	$7,428	$7,453	$7,477	$7,502	$7,526	$7,551
Portfolio 5c	$7,372	$7,416	$7,452	$7,503	$7,546	$7,589	$7,633	$7,676	$7,720
Portfolio 5a	$7,417	$7,461	$7,500	$7,549	$7,593	$7,638	$7,682	$7,726	$7,770

Figure 8.53 contains results for Scenario A: Carbon Tax Case. The portfolio ordering on cost does not change significantly in this scenario. Portfolios 4 and 5, which add 600-1000 MW of wind by 2030, are impacted the most by changes in the assumption for wind production. This analysis helps identify inflection points that change the unit economics for wind through time. IPL will continuously monitor trends in wind technology performance through time as future IRPs are developed.

Figure 8.53 | Wind Capacity Factor Sensitivity, Carbon Tax Case (PVRR, $MM)

	Wind Annual Capacity Factor →								
	46%	44%	Base (42%) ↓	40%	38%	36%	34%	32%	30%
Portfolio 3b	$7,640	$7,652	$7,661	$7,675	$7,686	$7,698	$7,709	$7,721	$7,733
Portfolio 5b	$7,649	$7,679	$7,703	$7,739	$7,769	$7,798	$7,828	$7,858	$7,888
Portfolio 3c	$7,688	$7,703	$7,716	$7,733	$7,748	$7,764	$7,779	$7,794	$7,809
Portfolio 5c	$7,619	$7,672	$7,716	$7,779	$7,832	$7,886	$7,939	$7,993	$8,046
Portfolio 3a	$7,707	$7,723	$7,737	$7,756	$7,772	$7,789	$7,805	$7,822	$7,838
Portfolio 4a	$7,659	$7,704	$7,740	$7,793	$7,837	$7,881	$7,926	$7,970	$8,015
Portfolio 4b	$7,671	$7,710	$7,742	$7,788	$7,827	$7,867	$7,906	$7,945	$7,984
Portfolio 4c	$7,691	$7,722	$7,747	$7,784	$7,815	$7,845	$7,876	$7,907	$7,938
Portfolio 5a	$7,718	$7,772	$7,819	$7,879	$7,933	$7,986	$8,040	$8,094	$8,148
Portfolio 2c	$7,909	$7,917	$7,923	$7,933	$7,941	$7,949	$7,958	$7,966	$7,974
Portfolio 2a	$7,927	$7,929	$7,932	$7,935	$7,937	$7,940	$7,943	$7,946	$7,948
Portfolio 1b	$7,945	$7,948	$7,950	$7,953	$7,956	$7,959	$7,961	$7,964	$7,967
Portfolio 2b	$7,944	$7,950	$7,956	$7,964	$7,970	$7,977	$7,983	$7,990	$7,996
Portfolio 1c	$7,972	$7,977	$7,980	$7,985	$7,990	$7,994	$7,999	$8,003	$8,008
Portfolio 1a	$8,009	$8,014	$8,018	$8,024	$8,029	$8,034	$8,039	$8,044	$8,050

8.4.4 Wind LMP Basis Sensitivity

IPL modeled new wind assets with a 20% basis adjustment to the LMP at the project, which means that the assumed LMP is 20% lower than the modeled MISO Indiana Hub price on average. This adjustment was made to account for the fact that wind is typically located in areas not near a load center and often see congestion putting downward pressure on LMPs. Forecasting congestion is difficult due to the myriad of factors that affect it, but the basis adjustment is an estimate to more accurately model the revenues that an actual wind project could receive.

IPL conducted a sensitivity analysis to evaluate the impact on PVRR if the basis adjustment was gradually removed. This informs the preferred portfolio selection by highlighting and quantifying a key risk variable when considering new wind projects.

This analysis was conducted for all 15 candidate portfolios for the Reference Case and Scenario A (Carbon Tax Case). Figure 8.54 contains the results for the Reference Case. In the Refence Case, changing the LMP basis assumption does not change the PVRR ranking of portfolios. Portfolios 4 and 5, which add 500 MW of wind starting in 2022, benefit the most from the wind revenue increase as each 5% increase in the wind captured revenue lowers the PVRR by $40-50M. However, the improved PVRR is not enough to close the gap between Portfolio 3 and Portfolios 4 and 5.

Figure 8.55 contains results for the Carbon Tax Case are in. The PVRR ranking for portfolios does change with just a 5% improvement in the basis assumption. Portfolio 5c is the lowest cost portfolio in the Carbon Tax Case with a 10% increase in wind captured revenue. This highlights the importance of future wind farm siting and congestion analysis to inform any new wind projects.

Figure 8.54 | Wind LMP Basis Sensitivity, Reference Case (PVRR, $MM)

	Base	Revenue +5%	Revenue +10%	Revenue +15%	Revenue +20%
Portfolio 3b	$6,976	$6,966	$6,956	$6,946	$6,937
Portfolio 3a	$7,016	$7,001	$6,987	$6,972	$6,958
Portfolio 3c	$7,034	$7,021	$7,008	$6,995	$6,982
Portfolio 2a	$7,132	$7,130	$7,128	$7,126	$7,124
Portfolio 1b	$7,176	$7,174	$7,172	$7,170	$7,168
Portfolio 2b	$7,188	$7,183	$7,178	$7,173	$7,168
Portfolio 2c	$7,191	$7,185	$7,178	$7,172	$7,166
Portfolio 1a	$7,215	$7,211	$7,207	$7,203	$7,199
Portfolio 1c	$7,223	$7,220	$7,216	$7,213	$7,210
Portfolio 4c	$7,269	$7,242	$7,215	$7,188	$7,161
Portfolio 4b	$7,293	$7,259	$7,225	$7,191	$7,158
Portfolio 4a	$7,295	$7,256	$7,218	$7,179	$7,140
Portfolio 5b	$7,400	$7,374	$7,348	$7,322	$7,296
Portfolio 5c	$7,452	$7,406	$7,360	$7,314	$7,268
Portfolio 5a	$7,500	$7,453	$7,407	$7,360	$7,314

Figure 8.55 | Wind LMP Basis Sensitivity, Carbon Tax Case (PVRR, $MM)

	Base	Revenue +5%	Revenue +10%	Revenue +15%	Revenue +20%
Portfolio 3b	$7,661	$7,649	$7,637	$7,625	$7,612
Portfolio 5b	$7,703	$7,672	$7,640	$7,608	$7,576
Portfolio 3c	$7,716	$7,699	$7,683	$7,667	$7,651
Portfolio 5c	$7,716	$7,660	$7,603	$7,547	$7,490
Portfolio 3a	$7,737	$7,720	$7,702	$7,685	$7,668
Portfolio 4a	$7,740	$7,693	$7,646	$7,599	$7,552
Portfolio 4b	$7,742	$7,701	$7,659	$7,618	$7,576
Portfolio 4c	$7,747	$7,715	$7,682	$7,649	$7,616
Portfolio 5a	$7,819	$7,763	$7,706	$7,649	$7,593
Portfolio 2c	$7,923	$7,915	$7,906	$7,898	$7,889
Portfolio 2a	$7,932	$7,929	$7,926	$7,923	$7,920
Portfolio 1b	$7,950	$7,947	$7,944	$7,941	$7,939
Portfolio 2b	$7,956	$7,949	$7,942	$7,935	$7,928
Portfolio 1c	$7,980	$7,976	$7,971	$7,966	$7,961
Portfolio 1a	$8,018	$8,013	$8,007	$8,002	$7,996

This sensitivity highlights the importance of wind farm siting as it pertains to transmission interconnection, localized congestion trends, and the overall robustness of the regional transmission grid. A detailed nodal, security-constrained production cost study would need to be conducted to further evaluate any specific project that IPL would consider in the future.

8.5 Preferred Resource Portfolio

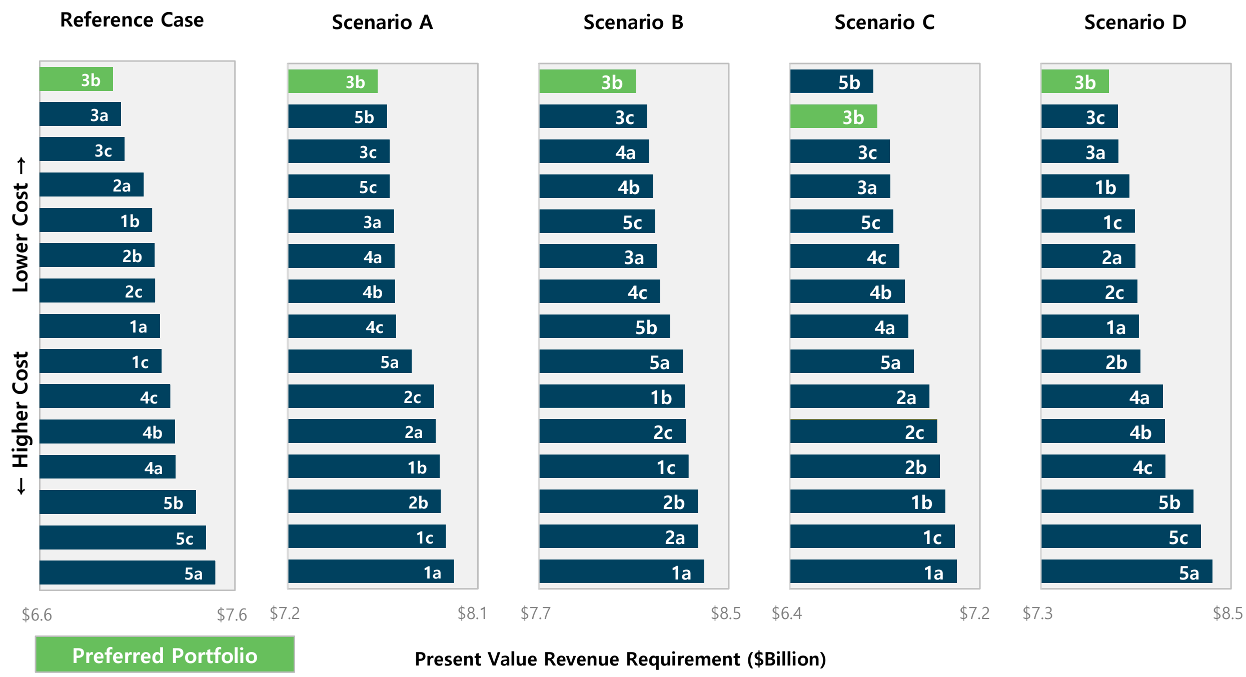
170 IAC 4-7-4(9) 170 IAC 4-7-6(a)(2) 170 IAC 4-7-8(c)(1) 170 IAC 4-7-8(c)(2) 170 IAC 4-7-8(c)(3)

1. **COST**

Portfolio 3b is the lowest-cost portfolio on a risk-adjusted basis across the widest range of futures. Short term costs are limited due to O&M and capital savings when Pete 1 and 2 retire, and IPL's net long position reduces the amount of firm capacity needed.

Pete 1 and 2 are the smallest, oldest units at Petersburg, and the model results strongly indicate that an earlier retirement date is the reasonable least cost plan for customers. Pete 1 and 2 require overhaul and maintenance cost over the next decade. The economic value as forecasted across many future scenarios shows that the retirement and replacement of these two units is the lowest cost options for IPL customers.

Figure 8.56 | Portfolio 3b: Lowest Cost Portfolio Across Wide Range of Futures



2. RISK

Identifying and quantifying risk in resource planning involves comprehensive evaluation of potential outcomes and testing different portfolios to see how robust they are if the world is different than expected. Portfolio 3b is the lowest cost portfolio on a risk-adjusted basis, provided a well-balanced portfolio in the short term while retaining flexibility to react to future market changes.

3. ENVIRONMENTAL

Portfolio 3b allows IPL to prudently and cost-effectively continue to decarbonize our portfolio over the next 5 years. Portfolio 3 would yield a reduction in carbon intensity of 50% compared to 2014 and 25% compared to Portfolio 1 that retains all coal units. In addition to a significant reduction in air emissions, the retirement of Petersburg Units 1 and 2 would decrease IPL's water intake at the plant by over 67%.

8.5.1 Financial Impact of Preferred Resource Portfolio

170 IAC 4-7-8(c)(7)(A) 170 IAC 4-7-8(c)(7)(B) 170 IAC 4-7-8(c)(7)(C) 170 IAC 4-7-8(c)(7)(D)

Figure 8.57 contains a breakdown of the portfolio cost for Portfolio 3b, the Preferred Resource Portfolio, compared to Portfolio 1b, which is the status quo portfolio with no change in retirement dates. Annual operating expenses are forecasted to decrease by approximately $104 million per year on average for the first ten years of the study, with most of those savings coming from fuel and O&M savings resulting from unit retirements. Recovery of and return on new capital expenditures, which includes the addition of new capacity to fill the expected capacity shortfall, is forecasted to increase $30-60 million per year from 2023 to 2029 for the Preferred Portfolio compared to the status quo. Because of the change in resource mix, annual energy market revenue and net capacity revenue is expected to decrease.

Figure 8.57 | 10-Year Portfolio Cost Difference: Preferred Portfolio vs. Status Quo

10-Year PVRR Breakdown (Nominal $MM) — **Portfolio 3b vs. Portfolio 1b, Reference Case**

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
OPERATING EXPENSES	Positive = more cost = ↑ PVRR				Negative = less cost = ↓ PVRR					
Energy Purchases	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fuel	$0	($25)	($20)	($77)	($76)	($80)	($89)	($90)	($92)	($98)
Variable O&M	$0	($3)	($2)	($8)	($8)	($9)	($10)	($10)	($10)	($10)
Fixed O&M	($13)	($16)	($22)	($25)	($44)	($38)	($34)	($46)	($36)	($36)
Emissions	$0	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)	($0)
Expense Gross Up	($0)	($1)	($1)	($2)	($2)	($2)	($2)	($2)	($2)	($2)
Subtotal: Operating Expenses	($13)	($44)	($45)	($113)	($130)	($129)	($134)	($148)	($141)	($147)
RECOVERY OF AND RETURN ON NEW CAPITAL	Positive = more cost = ↑ PVRR				Negative = less cost = ↓ PVRR					
Book Depreciation (New Capital)	($1)	($2)	$1	$13	$18	$19	$22	$23	$27	$28
Property Taxes	($0)	($0)	$0	$3	$3	$2	$1	$0	$0	$0
Return on Rate Base	($1)	($3)	($1)	$14	$29	$32	$32	$33	$34	$35
Subtotal: New Capital	($3)	($5)	$0	$30	$49	$52	$55	$56	$61	$64
MARKET REVENUES	Positive = less revenue = ↑ PVRR				Negative = more revenue = ↓ PVRR					
Energy Revenue ($MM)	($0)	$34	$19	$64	$51	$52	$58	$57	$54	$56
Capacity Revenue ($MM)	$0	$4	$5	$11	$10	$10	$10	$10	$9	$9
Subtotal: Market Revenue	($0)	$38	$24	$75	$62	$63	$68	$66	$63	$65
Annual Revenue Requirement [Line 7+11+14]	($17)	($11)	($21)	($8)	($19)	($14)	($12)	($26)	($17)	($18)

10-Year PVRR Difference @ 6.486% Discount Rate ($115)

The IRP is modeled at a snapshot in time with assumptions regarding numerous inputs including the cost for new replacement capacity. The annual revenue requirement calculation is not intended to be a precise forecast for the impact on rates based on the preferred portfolio. Any potential rate impacts of decisions stemming from this IRP will be considered in future regulatory filings.

Overall, the Preferred Resource Portfolio provides a measured transition period that enables IPL to efficiently finance any potential new projects in a timely and cost-effective manner for customers.

Section 9: Short Term Action Plan and Conclusion

170 IAC 4-7-4(24) 170 IAC 4-7-6(b)(4)(C) 170 IAC 4-7-9

9.1 IPL Short Term Action Plan

170 IAC 4-7-4(10)

9.1.1 2019 Short Term Action Plan (2020-2022)

- Continue implementation of approved 2020 DSM Plan (part of 2018-2020 plan)
- File for regulatory approval of a 2021-2023 DSM Plan consistent with the 2019 IRP
- Review and evaluate bids from all-source RFP facilitated by third-party (Sargent & Lundy).
- File for regulatory approval for replacement resources identified from the RFP
- Retire Petersburg Unit 1 by 2021
- Continue investment in grid modernization via proposed TDSIC Plan
- Retire Petersburg Unit 2 by 2023

Importantly, the Preferred Resource Portfolio preserves optionality because the short-term action plan is the same for Portfolios 3, 4 and 5. This means that even if IPL selected Portfolio 5 as the Preferred Portfolio, the company would not do anything different in the Short Term action window because of the lead time required to retire and replace large quantities of capacity.

The Short Term Action plan covering 2020 through 2022 includes offering DSM, replacing generation and completing transmission projects.

IPL will manage project costs and schedules and include a comparison of these short term IRP goals to what transpires in future IRPs.

Demand Side Management (DSM) Programs for 2021 – 2023

IPL has Commission approval to offer DSM programs for the 2018 to 2020 period (Cause No. 44945). IPL expects to file in late Q1 or early Q2 of 2020 for Commission authority to offer DSM programs for the three-year period 2021 through 2023. The proposed 2021-2023 DSM Plan will be consistent with the results of this IRP planning process.

The eight DSM bundles included in the IRP analysis represent the Realistic Achievable Potential (RAP) level of savings from the MPS which (all eight bundles) total approximately 2% of IPL sales. It is important to note that the MPS assumes that the RAP (2%) level of savings can only be achieved at a very high delivery cost under optimal market conditions. The DSM supply curve (Figure 5.41) demonstrates this – note the cost for measure delivery continues to escalate with each 0.25% of additional energy savings until costs are high for measures in the 1.75% - 2% decrement bundle. Therefore, it is important to use the IRP process to get to a level of savings that can be delivered under typical market conditions or to define a "Program Potential" level of savings. In the IRP modeling, the Present Value of Revenue Requirements (PVRR) continues to improve for each decrement of additional DSM through the selection of Decrement 4 or roughly 1% of annual sales. Including Decrements after Decrement 4 causes the PVRR to increase. Based on IPL's experience delivering programs in our service territory, the costs and savings at this 1% level are roughly consistent with our current offerings. However, this target will not be met without challenges.

The next step in developing the proposed 2021-2023 DSM Plan will be to collaborate with DSM implementation vendors and the IPL OSB to identify DSM programs that roughly align the cost and characteristics of the DSM measures that were identified in the Preferred Resource Portfolio by the IRP modeling. IPL has already initiated this process by initially targeting the IRP Decrement 4 results. IPL will face a significant challenge with the elimination of general service LED lighting measures from the residential program offerings. These lighting measures currently make up around 40% of residential energy savings. These measures have been removed starting in 2021 due to changes in the underlying baseline assumptions (LEDs are becoming the predominant lighting source). Preliminary forecasts for the Action Plan period indicate that the level of DSM in Decrement 4 will be challenging to achieve due to the removal of this general service LED lighting. As such, IPL plans to initially target a level of DSM between Decrement 3 and Decrement 4 for the 2021 – 2023 period as detailed in Figure 9.1 (these energy savings are net of free riders). Note that general service LED lighting will continue to be available through programs to the income qualified segment of customers where measure savings are still available.

Figure 9.1 | Net MWh DSM Target for the 2021 – 2023 Action Plan

Decrements 1 - 3 (Net MWh)	92,529	92,308	93,567
Decrement 1 - 4 (Net MWh)	119,719	124,673	125,425
DSM Action Plan Target (Net MWh)	92,529 - 119,719	92,308 - 124,673	93,567 - 125,425

***DSM level in Reference Case**

New demand response was not shown to be cost effective in the IRP; however, IPL will continue to maintain and use the existing load control devices as a load modifying resource. IPL included incentive and maintenance costs for the existing device population in the IRP analysis.

IPL expects to continue to offer income qualified programs and realize the current annual level of 1,500 – 2,000 MWhs of energy savings. Since IPL plans to offer these programs as a matter of policy, they were not included as selectable in the IRP analysis. Instead, the costs, energy savings and load shapes associated with these programs were non-selectable inputs in the analysis.

Supply Side (Generation) Plan for 2020 – 2022

IPL will release a Request for Proposals ("RFP") to procure replacement generation for needed capacity from the shortfall of Petersburg Units 1 & 2 retirements. IPL will evaluate the project bids to determine the appropriate replacement capacity for the retiring Petersburg units.

Transmission Short Term Action Plan for 2020 – 2022

The IPL transmission system projects listed below have been identified though annual transmission system performance assessments to establish baseline reliability projects or through MISO assessments.

- Rockville Substation 345 kV Ring Bus – 2020

The Rockville Substation project removes the risk of potential overloads under certain contingency events. Thermal ratings of equipment are exceeded for certain outage contingencies and IPL relies upon operating guides to reconfigure the system to meet the transmission system planning performance requirements of TPL-001-4. To mitigate this, IPL will install a new 345 kV breaker at the Rockville Substation to create a ring bus configuration. Cost Estimate: $3.6M.

- Petersburg – Gibson TMEP – 2020

The Petersburg to Gibson Targeted Market Efficiency Projects ("TMEP") was identified through an Interregional MISO and PJM process. The TMEP study looked to identify low-cost, quick implementation projects to relieve historically observed Market-to-Market congestion issues. This economic study identified an economic project with a B/C ratio of 4.5. To mitigate the congestion issue, IPL will replace two 345 kV breakers, relays, switches, and bus at the Petersburg substation. Cost Estimate: $4.3M.

- Guion Substation – 2023

The Guion Substation project removes the risk of potential overloads under certain contingency events. Thermal ratings of equipment are exceeded for certain outage contingencies and IPL relies upon operating guides to reconfigure the system to meet the transmission system planning performance requirements of TPL-001-4. To address this, IPL will add a 345/138 kV transformer and modify the existing substation configuration to include a 345 kV ring bus. This requires three new 345 kV breakers and two new 138 kV breakers. Cost Estimate: $14M.

- Stout Substation 345 kV Ring Bus – 2024

The Stout Substation project removes the risk of potential overloads under certain contingency events. Thermal ratings of equipment are exceeded for certain outage contingencies and IPL relies upon operating guides to reconfigure the system to meet the transmission system planning performance requirements of TPL-001-4. To mitigate this, IPL will install a new 345 kV breaker at the Stout Substation to create a ring bus configuration. Cost Estimate: $3.4M.

Timing of future projects are subject to change. See Section 3.2 of this IRP for a brief overview of IPL's TDSIC Plan.

9.1.2 Long Term Action Plan (2023 and Beyond)

Beyond the Short Term Action plan window, IPL's modeling and analysis efforts in this IRP have highlighted several key signposts, or market indicators, to evaluate as we move forward into the 2022 IRP.

First, the modeling clearly showed the potential impact of carbon legislation on influencing the optimal mix of technologies in our resource mix. The federal election in 2020 will be a major event to watch as federal climate and energy goals are formed over the next three years.

Second, the results from IPL's all-source RFP will provide first-hand market knowledge of the types of commercially available projects that are available today. The pricing and execution of new replacement capacity will be critical to understanding how to shape long-term forecasts for wind, solar, and storage.

Third, the evolution of the MISO market, including MISO's efforts with RIIA and RAN, could influence how we approach long term planning in the face of uncertainty on RTO policy and rules.

Overall, IPL will continue to evaluate existing resources, including Petersburg units 3 and 4, as we enter the 2022 IRP planning process.

9.2 Expectations for Future Improvements

170 IAC 4-7-4(16) 170 IAC 4-7-5(a)(9) 170 IAC 4-7-8(c)(9)

IPL plans to continue its effort to improve its IRP process and has identified the following items to do so.

- **IPL plans to improve load research and load forecasting by using AMI data.** Currently, IPL's load research sampling is performed through a statistically representative sample of load research meters installed throughout the service territory. This sample has become somewhat dated due to customer's changing locations. IPL plans to work with Itron to replace the load research meters with the AMI meters for load research. The changeover to AMI meters will eliminate load research meter deployment costs and result in more robust customer samples. Additionally, IPL has plans to work with an external consultant to explore load forecasting at the customer meter level using the AMI data. These forecasts will help IPL better understand usage trends which includes identifying customer deployment of DERs and EVs.
- **Seasonal capacity assessment:** Resource capacity credit can vary by season, requiring careful consideration of a portfolio used to serve load reliably. MISO continues to evaluate the existing capacity construct that IPL participates in through a stakeholder process. Changes to the capacity construct that include seasonality as opposed to an annual consideration could have a significant impact on the capacity credit for renewables.
- **Hourly and sub-hourly modeling:** Hourly and sub-hourly modeling allows IPL to evaluate its ability to meet load for all hours. Some resources such as batteries offer exceptional flexibility. This value may be more accurately captured by sub-hourly modeling, though this currently pushes the limits of many available models. IPL will continue assess whether the value of more granular modeling justifies the increase in complexity.
- **Explore modeling DSM, EE, and DR shapes hourly and sub-hourly to assess peak reduction, load shifting value:** Hourly and sub-hourly shapes for DSM, EE, and DR allow IPL to evaluate more accurately how these resources can contribute towards meeting load obligations.
- **Dynamic wind, solar, and storage ELCC:** Wind, solar, and storage's ability to meet reserve requirements is influenced by the penetration of each resource. Therefore, allowing for a dynamic ELCC value that provides feedback based on model selections could produce a more comprehensive optimization. IPL will continue to evaluate this consideration and its feasibility in available models.
- **"Bottom up" electric vehicle and distributed solar forecast integrated with generation, transmission, and distribution planning:** Electric vehicles and solar distribution are closely tied

to IPL's transmission and distribution system. As penetration of these resources increases, the need to incorporate grid infrastructure becomes more important and IPL will continue to evaluate the feasibility of doing so.

- **Scenario planning centered around decarbonization pathways that prioritize least cost, reliability, and effectiveness:** IPL's 2019 IRP has informed the importance of a carbon tax on influencing the optimal plan for customers. IPL will continue to monitor research and policies that influence the viability of resources.

9.3 Conclusion

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

The IRP is the foundation for future regulatory requests based upon a holistic view of IPL's resource needs and portfolio options. IPL has made strides to create a fair, balanced, transparent, and stakeholder informed IRP in the 2019 IRP Planning Process. The Preferred Portfolio provides a reasonable and balanced transition pathway that provides clear off-ramps for remaining coal units. The probabilistic assessment of risk and uncertainty that was embedded in the modeling and decision process provides a data-driven framework to build upon through the passage of time. IPL will continue to build the tools and capabilities that allow us to shape our long-term resource plan in the best interest of customers.

Section 10: Attachments & Rule Reference Table

Public Attachments are available in Volumes 2 & 3 of the Public IRP Report

Confidential Attachments & the Technical Appendix are available as part of the Confidential IRP

Attachment 1.1 (IPL 2019 IRP Non-Technical Summary)

Attachment 1.2 (Public Advisory Meeting Presentations) **170 IAC 4-7-4(30)**

Attachment 3.1 (Smart Grid 2017 & 2018 Annual Reports)

Attachment 3.2 (Rate REP Projects Map)

Attachment 4.1 (Test Year July 2016 through June 2017 Hourly Loads – MW) **170 IAC 4-7-4(12) 170 IAC 4-7-4(14) 170 IAC 4-7-5(a)(1) 170 IAC 4-7-5(a)(2)**

Attachments 4.2a – g (EIA End Use Data - Indices) **170 IAC 4-7-4(12)**

Attachment 4.3 (End Use Modeling Technique) **170 IAC 4-7-4(12)**

Confidential Attachment 4.4a (Moody's Q4 2018 Base) **170 IAC 4-7-4(12)**

Confidential Attachment 4.4b (Moody's Q4 2018 Exceptionally Strong) **170 IAC 4-7-4(12)**

Confidential Attachment 4.4c (Moody's Q4 2018 Lower Trend) **170 IAC 4-7-4(12)**

Attachment 4.5 (10 Yr. Energy and Peak Forecast) **170 IAC 4-7-4(12)**

Attachment 4.6 (20 Yr. High, Base and Low Forecast) **170 IAC 4-7-4(1) 170 IAC 4-7-4(3) 170 IAC 4-7-4(12) 170 IAC 4-7-6(a)(5) 170 IAC 4-7-5(b)(1) 170 IAC 4-7-5(b)(2) 170 IAC 4-7-5(b)(3)**

Attachment 4.7a (Energy Input Data–Residential) **170 IAC 4-7-4(12) 170 IAC 4-7-5(a)(3)**

Attachment 4.7b (Energy Input Data–Small C&I) **170 IAC 4-7-4(12) 170 IAC 4-7-5(a)(3)**

Attachment 4.7c (Energy Input Data–Large C&I) **170 IAC 4-7-4(12) 170 IAC 4-7-5(a)(3)**

Attachment 4.8 (Peak–Forecast Drivers and Input Data) **170 IAC 4-7-4(12)**

Attachment 4.9 (Forecast Error Analysis) **170 IAC 4-7-4(2) 170 IAC 4-7-4(12) 170 IAC 4-7-5(a)(6)**

Attachment 5.1 (IPL 2018 DSM MPS) **170 IAC 4-7-4(15) 170 IAC 4-7-6(b)(2)(B) 170 IAC 4-7-6(b)(2)(D) 170 IAC 4-7-6(b)(2)(E)**

Attachment 5.2a (MPS Appendix B – Residential Electric Measure Detail)

Attachment 5.2b (MPS Appendix C – Commercial Electric Measure Detail)

Attachment 5.2c (MPS Appendix D – Industrial Electric Measure Detail)

Attachment 5.3 (Decrement Load Shapes Summary) **170 IAC 4-7-6(b)(2)(D) 170 IAC 4-7-6(b)(2)(E)**

Confidential Attachment 5.4 (Avoided Cost) **170 IAC 4-7-4(29) 170 IAC 4-7-8(c)(6)**

Confidential 7.1 (Wood Mackenzie H1 2018 No Federal Carbon Case Report)

Confidential 7.2 (Wood Mackenzie H1 2018 Federal Carbon Case Report)

Confidential 7.3 (Wood Mackenzie H1 2018 Federal Carbon Case Report – MISO)

Confidential Attachment 7.4 (Wood Mackenzie - H1 2018 Supply, Demand Energy, Federal Carbon Case)

Confidential Attachment 7.5 (Wood Mackenzie - H1 2018 Supply, Demand Energy, No Carbon Case)

Confidential 7.6 (Annual Generator Fuel Prices) **170 IAC 4-7-6(a)(3)**

Attachment 8.1 (Annual Energy Charts) **170 IAC 4-7-8(c)(5)**

Attachment 8.2 (Load Resource Balance by Scenario)

Attachment 8.3 (Market Purchases and Sales)

Rule Reference Table

170 IAC 4-7 (Readopted Filed Verison 4/11/19)		
Regulatory Requirement	**Rule Reference**	**Section and/or Attachment in Indianapolis Power & Light Company 2019 IRP Report**
0.5 - Purpose and applicability	-	No Response Required
1 - Definitions	-	No Response Required
2 - Integrated resource plan submission	-	-
2.1 - Confidentiality	-	-
2.2 - Public comments and director's reports	-	No Response Required
2.3 - Resource adequacy assessment report	-	No Response Required
2.4 - N/A	-	-
2.5 - Effects of integrated resource plans in docketed proceedings	-	No Response Required
2.6 - Public advisory process	170 IAC 4-7-2.6	Section 1.4 & Attachment 1.2
2.7 - Contempory issues technical conference	-	-
3 - Waiver or variance requests	-	No Response Required
4 - Integrated resource plan contents		
(1) Twenty-year forecast	170 IAC 4-7-4(1)	Section 4.3, Attachment 4.6
(2) Analysis of historical and forecasted peak demand and energy usage	170 IAC 4-7-4(2)	Section 4.5, Attachment 4.9
(3) Alternative forecasts of peak demand and energy usage	170 IAC 4-7-4(3)	Section 4.3, Attachment 4.6
(4) Description of existing resources	170 IAC 4-7-4(4)	Section 5.1
(5) Process for selecting possible future resources	170 IAC 4-7-4(5)	Sections 7.2 & 7.3
(6) Description of possible future resources	170 IAC 4-7-4(6)	Sections 5.2, 5.3, & 5.4
(7) Screening analysis and resource summary table	170 IAC 4-7-4(7)	Section 5.2
(8) Candidate resource portfolios	170 IAC 4-7-4(8)	Sections 7.1, 8.1, & 8.2.1
(9) Preferred resource portfolio	170 IAC 4-7-4(9)	Section 8.5
(10) Short-term action plan	170 IAC 4-7-4(10)	Section 9.1
(11) Inputs, methods, and definitions used by the utility in this IRP	170 IAC 4-7-4(11)	Sections 4,5 & 7
(12) Data sets and sources	170 IAC 4-7-4(12)	Section 4 Attachments
(13) Efforts to develop a database of electricity consumption patterns	170 IAC 4-7-4(13)	Section 4.1
(14) Suggested methods for developing database in (13)	170 IAC 4-7-4(14)	Attachment 4.1
(15) Schedule for customer surveys	170 IAC 4-7-4(15)	Section 5.4.3, Attachment 5.1
(16) Usage of AMI data	170 IAC 4-7-4(16)	Sections 3.3.2, 4.1, & 9.2
(17) Contemporary issues designated	170 IAC 4-7-4(17)	Section 1.5
(18) Distributed generation	170 IAC 4-7-4(18)	Sections 3.2 & 3.4.1
(19) Model structure and applicability	170 IAC 4-7-4(19)	Section 7.2
(20) Fuel inventory and procurement planning	170 IAC 4-7-4(20)	Section 2.2
(21) Emission allowance inventory and procurement planning	170 IAC 4-7-4(21)	Section 6.2.1
(22) Generation expansion planning criteria	170 IAC 4-7-4(22)	Section 7
(23) Consideration of compliance costs	170 IAC 4-7-4(23)	Section 6
(24) Resource planning objectives	170 IAC 4-7-4(24)	Executive Summary and Sections 1.1, 8 & 9
(25) Base case scenario	170 IAC 4-7-4(25)	Section 8.3.1
(26) Alternative scenarios	170 IAC 4-7-4(26)	Sections 7.3.2, 8.3.2, 8.3.3, 8.3.4 & 8.3.5
(27) Description of power flow models and transmission planning criteria	170 IAC 4-7-4(27)	Sections 2.3.2 & 2.3.3
(28) List and description of methods	170 IAC 4-7-4(28)	Sections 4.3 & 7.2
(29) Avoided cost calculation	170 IAC 4-7-4(29)	Section 5.4.5 & Confidential Attachment 5.4
(30) Summary of public advisory process	170 IAC 4-7-4(30)	Section 1.4 & Attachment 1.2
(31) Assessment of resources considered	170 IAC 4-7-4(31)	Sections 5.2, 5.3 & 5.4
5 - Energy and demand forecasts		
(a)(1) Historical load shapes	170 IAC 4-7-5(a)(1)	Attachment 4.1
(a)(2) Disaggregation of data	170 IAC 4-7-5(a)(2)	Attachment 4.1
(a)(3) Actual and weather-normalized levels	170 IAC 4-7-5(a)(3)	Attachment 4.7 a-c
(a)(4) Methods to weather-normalize	170 IAC 4-7-5(a)(4)	Section 4.3
(a)(5) 20-year energy and demand forecasts	170 IAC 4-7-5(a)(5)	Attachment 4.6
(a)(6) 10-year historical analysis	170 IAC 4-7-5(a)(6)	Attachment 4.9
(a)(7) Impact of historical DSM programs on load forecast	170 IAC 4-7-5(a)(7)	Section 4.3
(a)(8) Justification for forecast methodology	170 IAC 4-7-5(a)(8)	Section 4.3
(a)(9) Potential improvements for forecasting	170 IAC 4-7-5(a)(9)	Section 9.2
(a)(10) Data sources for historical analysis	170 IAC 4-7-5(a)(10)	Section 4.5
(b)(1) Alternative forecasts - high	170 IAC 4-7-5(b)(1)	Attachment 4.6
(b)(2) Alternative forecasts - low	170 IAC 4-7-5(b)(2)	Attachment 4.6
(b)(3) Alternative forecasts - most probable	170 IAC 4-7-5(b)(3)	Attachment 4.6
(c) Suggested inputs for most probable forecast	-	No Response Required

6 - Description of available resources		
(a)(1) Net and gross dependable generating capacity	170 IAC 4-7-6(a)(1)	Section 5.1.1
(a)(2) Expected changes to existing capacity	170 IAC 4-7-6(a)(2)	Sections 5.1.1 & 8.5
(a)(3) Fuel price forecasts by existing generating unit	170 IAC 4-7-6(a)(3)	Confidential Attachment 7.1
(a)(4) Environmental effects at existing fossil generating units	170 IAC 4-7-6(a)(4)	Section 6
(a)(5) Analysis of existing transmission system	170 IAC 4-7-6(a)(5)	Section 2
(a)(6) Discussion of demand-side resources	170 IAC 4-7-6(a)(6)	Sections 4.3 & 5.4
(b)(1) Rate design as a resource	170 IAC 4-7-6(b)(1)	Section 5.4.5
(b)(2)(A) Description of potential DSM resources	170 IAC 4-7-6(b)(2)(A)	Section 5.4
(b)(2)(B) Methods by which DSM resource characteristics are determined	170 IAC 4-7-6(b)(2)(B)	Section 5.4.3 & Attachment 5.1
(b)(2)(C) Customer class affected by potential DSM resources	170 IAC 4-7-6(b)(2)(C)	Sections 5.4.2 & 5.4.3
(b)(2)(D) Annual and lifetime energy and savings for potential DSM resources	170 IAC 4-7-6(b)(2)(D)	Attachments 5.1 & 5.3
(b)(2)(E) Impact of potential DSM on load, capacity and T&D requirements	170 IAC 4-7-6(b)(2)(E)	Attachments 5.1 & 5.3
(b)(2)(F) Ability of all ratepayers to participate in DSM	170 IAC 4-7-6(b)(2)(F)	Section 5.4.1
(b)(3)(A) Description of supply-side resources considered	170 IAC 4-7-6(b)(3)(A)	Sections 5.2 & 5.3
(b)(3)(B) Description of efforts to coordinate planning with other utilities	170 IAC 4-7-6(b)(3)(B)	Section 2.3
(b)(3)(C) Environmental effects of supply-side resources considered	170 IAC 4-7-6(b)(3)(C)	Section 8.3.8
(b)(4)(A) Transmission resources considered	170 IAC 4-7-6(b)(4)(A)	Section 2.3
(b)(4)(B) For transmission resources, timing, types, and alternatives considered	170 IAC 4-7-6(b)(4)(B)	Section 2.3
(b)(4)(C) Cost of expected transmission projects	170 IAC 4-7-6(b)(4)(C)	Section 9.1
(b)(4)(D) Value of transmission upgrades	170 IAC 4-7-6(b)(4)(D)	Section 2
(b)(4)(E) How IRP affects RTO planning and RTO planning affects IRP	170 IAC 4-7-6(b)(4)(E)	Section 2
7 - Selection of resources		
8 - Resource portfolios		
(a) Process for selecting candidate portfolios	170 IAC 4-7-8(a)	Section 7
(b) Candidate portfolio performance across scenarios	170 IAC 4-7-8(b)	Section 8.3
(c)(1) Preferred resource portfolio	170 IAC 4-7-8(c)(1)	Section 8.5
(c)(2) Standards of reliability	170 IAC 4-7-8(c)(2)	Section 8.5
(c)(3) Assumptions having greatest effect on preferred resource portfolio	170 IAC 4-7-8(c)(3)	Section 8.5
(c)(4) Analysis showing that supply-side and DSM have been considered on a consistent basis	170 IAC 4-7-8(c)(4)	Sections 7 & 8
(c)(5) Analysis showing that portfolio meets demand	170 IAC 4-7-8(c)(5)	Attachment 8.1
(c)(6) Analysis of DSM deferring T&D investment	170 IAC 4-7-8(c)(6)	Confidential Attachment 5.4
(c)(7)(A) Operating and capital cost of preferred portfolio	170 IAC 4-7-8(c)(7)(A)	Section 8.5.1
(c)(7)(B) Avg. cost/kWh of future resources	170 IAC 4-7-8(c)(7)(B)	Section 8.5.1
(c)(7)(C) Avoided cost in each year for preferred portfolio	170 IAC 4-7-8(c)(7)(C)	Section 8.5.1
(c)(7)(D) Ability to finance preferred portfolio	170 IAC 4-7-8(c)(7)(D)	Section 8.5.1
(c)(8) How preferred portfolio balances cost, reliability, risk	170 IAC 4-7-8(c)(8)	Section 8
(c)(9) Discussion of potential improvements	170 IAC 4-7-8(c)(9)	Section 9.2
(c)(10) Strategy for adapting to change in assumptions	170 IAC 4-7-8(c)(10)	Section 9.3
9 - Short term action plan	170 IAC 4-7-9	Section 9
10 - IRP updates	-	-